MARATHON OIL CORP
Form 10-K
February 25, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2015
Commission file number 1-5153
Marathon Oil Corporation
(Exact name of registrant as specified in its charter)

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

5555 San Felipe Street, Houston, TX 77056-2723
(Address of principal executive offices)
(713) 629-6600
(Registrant’s telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes R 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 R
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 R 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 R No £
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. £
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer R 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 R
The aggregate market value of Common Stock held by non-affiliates as of June 30, 2015: $17,916 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 676,886,641 shares of Marathon Oil Corporation Common Stock outstanding as of February 15, 2016.
Documents Incorporated By Reference:
Portions of the registrant’s proxy statement relating to its 2016 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.

AMPCO – Atlantic Methanol Production Company LLC, a company located in Equatorial Guinea in which we own a 45% 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% non-operated working interest.

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

bcf – Billion cubic feet.

boe – Barrels of oil equivalent.

btu – British thermal unit, an energy equivalence measure.

Capital Program – Includes capital expenditures, cash investments in equity method investees and other investments, exploration costs that are expensed as incurred rather than capitalized, such as geological and geophysical costs and certain staff costs, and other miscellaneous investment expenditures.

DD&A – Depreciation, depletion and amortization.

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 on June 30, 2011 and treated as discontinued operations.

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, a liquefied natural gas production company located in E.G. in which we own a 60% equity interest.

EIA – United States Energy Information Agency.

EPA – United States Environmental Protection Agency.

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

FASB – Financial Accounting Standards Board.

FPSO - Floating production, storage and offloading vessel.

Henry Hub price - a natural gas benchmark price quoted at settlement date average.

IRS – United States Internal Revenue Service.

LNG – Liquefied natural gas.

LPG – Liquefied petroleum gas.

Liquid hydrocarbons or liquids – Collectively, crude oil, synthetic crude oil, condensate and natural gas liquids.

LLS – Louisiana Light Sweet crude oil, an oil index benchmark price as per Bloomberg Finance LLP: LLS St. James.

Marathon Oil – Marathon Oil Corporation and its consolidated subsidiaries: the company as it exists following the June 30, 2011 spin-off of the downstream business.

mbbld – Thousand barrels per day.

mboed – Thousand barrels of 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.
mmta – Million metric tonnes per annum.
MPC - Marathon Petroleum Corporation – The separate independent company which now owns and operates the downstream business.
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.
NYMEX - New York Mercantile Exchange.
OECD – Organization for Economic Cooperation and Development.
OPEC – Organization of Petroleum Exporting Countries.
Operational availability – A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time, after consideration of internal losses.
Productive well – A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.
Proved developed reserves – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Proved reserves – Proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves are those quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
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 or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
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 liquid hydrocarbons and natural 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.
SCOOP – South Central Oklahoma Oil Province.
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).
STACK – Sooner Trend, Anadarko (basin), Canadian (and) Kingfisher (counties).

TD - Total depth or the bottom of a drilled hole.
Total proved reserves – The summation of proved developed reserves and proved undeveloped reserves.
U.K. – United Kingdom.
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 with monthly pricing based upon average WTI adjusted for differentials unique to western Canada.
Working interest – 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 sometimes burdened by overriding royalty interest or other interests.
WTI – West Texas Intermediate crude oil, an oil index benchmark price as quoted by NYMEX.

Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: our operational, financial and growth strategies, including drilling plans and projects, planned wells, rig count, inventory, seismic, exploration plans, maintenance activities, drilling and completion improvements, workforce reductions and expected savings, cost reductions, non-core asset sales, and financial flexibility; our ability to successfully effect those strategies and the expected timing and results thereof; our 2016 Capital Program and the planned allocation thereof; planned capital expenditures and the impact thereof; expectations regarding future economic and market conditions and their effects on us; our ability and strategies to manage through the lower commodity price cycle; our financial and operational outlook, and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources, and the benefits thereof; resource and asset potential; reserve estimates; growth expectations; and future production and sales expectations, and the drivers thereof. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as “anticipates,” “believes,” “estimates,” “expects,” “targets,” “plans,” “projects,” “could,” “may,” “should,” “would” or similar words indicating that futur are uncertain. While we believe that our assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including pricing and supply/demand levels for crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- changes in expected reserve or production levels;
- changes in political or economic conditions in key operating markets, including international markets;
- capital available for exploration and development;
- well production timing;
- availability of drilling rigs, materials and labor;
- difficulty in obtaining necessary approvals and permits;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- cyber-attacks;
- changes in safety, health, environmental and other regulations;
- other geological, operating and economic considerations; and
- other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we assume no duty to revise or update any forward-looking statements whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I
Item 1. Business
General
Marathon Oil Corporation is an independent global exploration and production company based in Houston, Texas, with operations in North America, Europe and Africa. Our corporate headquarters are located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our telephone number is (713) 629-6600. Each of our three reportable operating segments is organized based upon both geographic location and the nature of the products and services it offers.

- North America E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining – 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.

We were incorporated in 2001. On June 30, 2011, we completed the spin-off of our downstream business, creating two independent energy companies: Marathon Oil and MPC.

Strategy and Results Summary

Marathon Oil's strategy is to safely and sustainably deliver value by investing in low cost, liquids-rich projects with a focus on risk-adjusted rates of return. We are focused in the high quality core of three premier unconventional resource plays in the U.S.: the Eagle Ford, Bakken and Oklahoma Resource Basins. Our strategy for our operated conventional producing assets in E.G., the U.K. and the U.S. is to maximize value and cash flow to provide flexibility to invest in the shorter cycle opportunities in the U.S. resource plays. Our conventional exploration program is currently limited to existing commitments in the Gulf of Mexico and Gabon. Our strategy is guided by the following seven strategic imperatives ("SI^7"):

1. Living Our Values
2. Investing in Our People
3. Continuous Improvement in Operational and Capital Efficiency
4. Driving Profitable and Sustainable Growth
5. Rigorous Portfolio Management
6. Quality and Material Resource Capture
7. Delivering Long-Term Shareholder Value

Commodity prices are the most significant factor impacting our revenues, profitability, operating cash flows and the amount of capital available to reinvest into our business. The low pricing environment has presented several challenges for us and our industry. We responded to the lower commodity prices in a number of ways:

- Reduced our 2015 Capital Program by approximately 50% from the prior year, down to $3 billion
- Established our 2016 Capital Program at $1.4 billion
- Exercised cost discipline, significantly reducing drilling and completion, production and general and administrative costs
- Drove sustainable operational efficiency gains in the U.S. unconventional resource plays
- Scaled back our conventional exploration program to focus on our U.S. unconventional resources plays
- Increased our target for non-core asset sales, now $750 million to $1 billion, up from our previous goal of $500 million
  - Closed over $300 million of non-core asset sales (excluding closing adjustments)
- Protected our liquidity and capital structure:
  - Issued $2 billion aggregate principal amount of unsecured senior notes ($1 billion of which was used to repay the 0.90% senior notes that matured in November 2015)
  - Increased the capacity of the revolving credit facility from $2.5 billion to $3.0 billion while also extending the maturity date an additional year to May 2020

Decreased our quarterly dividend from $0.21 to $0.05 per share, saving approximately $425 million of cash on an annualized basis

In 2015, we continued to focus on the U.S. unconventional resource plays. We progressed co-development in the Eagle Ford, further delineated Austin Chalk in the Eagle Ford along with SCOOP/STACK in the Oklahoma Resource Basins and improved overall competitiveness in the Bakken with cost reductions and enhanced completions. Our U.S. operations added 73 mmboe proved reserves in 2015, excluding acquisitions, dispositions and production, amounting to an increase of 107% over the prior year's ending balance.

Net sales volumes from continuing operations increased by 6% to 438 mboed in 2015 from 415 mboed in 2014. Volumes from our three U.S. resource plays totaled 218 mboed, an increase of 20% from 181 mboed in 2014. For the total company, we ended 2015 with proved reserves of approximately 2,163 mmboe as compared to 2,198 mmboe at the end of 2014.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Outlook, for a more detailed discussion of our operating results, cash flows and outlook, including the 2016 Capital Program.

The map below shows 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 7 to the consolidated financial statements.

In the following discussion regarding our North America E&P, International E&P and Oil Sands Mining segments, references to net wells, acres, sales or investment indicate our ownership interest or share, as the context requires.

North America E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in the U.S. and Canada. Our primary focus in the North America E&P segment is concentrated within our unconventional resource plays. The following tables provide additional detail regarding net sales volumes, sales mix and operated drilling activity:

Net Sales Volumes	2015	Increase (Decrease)	2014	Increase (Decrease)	2013
Equivalent Barrels (mboed)					
Eagle Ford	134	20 %	112	38 %	81
Oklahoma Resource Basins	25	39 %	18	29 %	14
Bakken	59	16 %	51	31 %	39
Other North America [(a)]	51	(11)%	57	(15)%	67
Total North America E&P (mboed)	269	13 %	238	18 %	201

(a) Includes Gulf of Mexico and other conventional onshore U.S. production

Sales Mix - U.S. Resource Plays - 2015	Eagle Ford	Oklahoma Resource Basins	Bakken
Crude oil and condensate	60 %	19 %	87 %
Natural gas liquids	19 %	28 %	7 %
Natural gas	21 %	53 %	6 %

Drilling Activity - U.S. Resource Plays	2015	2014	2013
Gross Operated			
Eagle Ford:			
Wells drilled to total depth	251	360	299
Wells brought to sales	276	310	307
Oklahoma Resource Basins:			
Wells drilled to total depth	20	19	10
Wells brought to sales	21	18	9
Bakken:			
Wells drilled to total depth	35	83	76
Wells brought to sales	56	69	77

Eagle Ford - As of December 31, 2015, we had approximately 153,000 net acres in the Eagle Ford in south Texas and 1,236 gross (911 net) operated producing wells, where we have been operating since 2011.

Of the 276 gross wells brought to sales in 2015, 56 were in the Austin Chalk, 28 were in the Upper Eagle Ford and 192 were in the Lower Eagle Ford. Of the 310 gross wells brought to sales in 2014, 22 were in the Austin Chalk and four were in the Upper Eagle Ford. Our 2015 average spud-to-TD time was 11 days compared to 13 days in 2014. Our high-density pad drilling continues to average approximately four wells per pad in 2015. The continued focus on stimulation design has contributed to incremental improvements in well performance across our area of activity.

During 2015, we continued evaluation of the Austin Chalk formation and began delineation of Upper Eagle Ford across our acreage position in south Texas, with a total of 22,000 Austin Chalk acres and 16,500 Upper Eagle Ford acres now delineated. The mix of crude oil and condensate, NGLs and natural gas from the Austin Chalk wells is similar to Eagle Ford condensate wells. Co-development of the Austin Chalk, Upper and Lower Eagle Ford horizons will leverage the infrastructure investments we have made to support production growth across the Eagle Ford operating area.

We operate approximately 800 miles of gathering pipeline in the Eagle Ford area. We now have 32 central gathering and treating facilities, with aggregate capacity of more than 475 mboed. 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.

In late 2015, we connected to a newly constructed third-party liquids pipeline, which allowed us to increase the amount of our Eagle Ford production transported by pipeline to 90% at year-end, up from an average of 70% during 2014. The ability to transport more barrels by pipeline enables us to improve/optimize price realizations, reduce costs, improve reliability and lessen our environmental footprint.

Approximately 42% of our 2016 Capital Program, $600 million, is allocated to the Eagle Ford. We expect drilling activity to average five rigs in 2016. Our drilling plans for 2016 include drilling 91 - 96 net wells (150 - 160 gross, of which we will operate 134 - 141). We anticipate bringing 124 - 132 gross operated wells to sales during 2016.

Oklahoma Resource Basins – Our primary focus in 2016 will be in the SCOOP and STACK areas. In the SCOOP and STACK areas we hold approximately 265,000 net acres with rights to the Woodford, Springer, Meramec, Granite Wash and other Pennsylvanian and Mississippian plays. This includes 8,000 net acres added in the Oklahoma Resource Basins, primarily in the STACK Meramec play during 2015.

Approximately 90% of our SCOOP acreage is held by production. In the SCOOP Woodford, we delineated over 70% of our acreage. We estimate the SCOOP Springer has a high oil yield that is about 85% liquids. We believe about 80% of our acreage in STACK has the potential for co-development of multiple horizons. About 67,000 STACK Woodford acres are delineated while approximately 42,000 acres of STACK Meramec acreage is delineated.

Approximately 14% of our 2016 Capital Program, $204 million, is allocated to the Oklahoma Resource Basins, which will support two rigs and lease retention in the STACK and delineation of the SCOOP Springer and Meramec. Our drilling plans for the Oklahoma Resource Basins in 2016 call for drilling and completing 23 - 28 net wells (65 - 75 gross, of which 24 - 27 are company operated wells). We anticipate bringing 20 - 22 gross operated wells to sales during 2016.

Bakken – We hold approximately 277,000 net acres in the Bakken shale oil play in North Dakota and eastern Montana, where we have been operating since 2006. We continue to see improvement in efficiency and well performance through optimizing completion techniques. We successfully completed a 55-well enhanced completion trial program that began in late 2014 and continued through 2015. We will continue executing and evaluating enhanced completion designs, including increased stage counts, high proppant volumes and fluid types as opportunities arise in 2016. Our large scale water gathering system is currently handling over 50% of our produced water. With a second phase expected to be fully operational in the second half of 2016, we anticipate this system will manage 80% of produced water by year end.

Our time to drill a well averaged 15 days spud-to-TD in 2015 compared to 17 days in 2014. We recompleted 11 wells during 2015. In efforts to optimize price realizations, we sell our production in local North Dakota markets and to select purchasers who may elect to transport outside the state.

Approximately 13% of our 2016 Capital Program, $193 million, is allocated to the Bakken, which will support one rig in 2016. Our 2016 Bakken program includes plans to drill 10 - 12 net wells (45 - 55 gross, of which we will operate 8 - 10). We anticipate bringing 13 - 15 gross operated wells to sales during 2016.

Other North America

During 2015, we further emphasized our focus on the U.S. unconventional resource plays, continued to maximize cash generation from our conventional assets and continued to dispose of non-core assets. In August 2015, we closed the sale of our East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets. In December 2015, we closed the sale of our operated producing properties in the greater Ewing Bank area and non-operated producing interests in the Petronius field in the Gulf of Mexico. In February 2016, we closed the sale of our non-operated producing interests in the Neptune field in the Gulf of Mexico. These assets collectively produced approximately 14 mboed in 2015.

Other North America consists primarily of onshore production operations in Wyoming and development activities in the Gulf of Mexico. In the Gulf, development work continues in the Gunflint field located on Mississippi Canyon Blocks 948, 949, 992 (N/2) and 993 (N/2). The development wells were completed in 2015. First oil is expected in mid-2016 after the completion of work at the third-party Gulfstar 1 host facility. We hold an 18% non-operated working interest in the Gunflint field.

A deepwater oil discovery on the Shenandoah prospect, located on Walker Ridge Block 51, was drilled in 2009. We own a 10% non-operated working interest in this prospect. The first appraisal well on the Shenandoah prospect reached total depth in 2013 and was successful. The operator drilled a second appraisal well in 2014, which was unsuccessful. A third appraisal well was spud in 2015, and was successfully sidetracked, logged and cored, finding more than 620 feet of net oil pay. A fourth appraisal well is expected to be spud in the first quarter of 2016.

Wyoming - We have ongoing waterflood and enhanced oil recovery projects in the mature Big Horn and Wind River Basins. Marathon is the third largest oil producer in the state of Wyoming. We also have conventional natural gas operations in the Greater Green River Basin.

Our Wyoming net sales averaged 17 mbbld of liquid hydrocarbons and 4 mmcfd of natural gas, or 17 mboed, during 2015 compared to 18 mboed in 2014. In addition, Marathon owns the 420-mile Red Butte Pipeline which connects oil fields in the Big Horn Basin to both the Silvertip Station on the Montana/Wyoming state line and to alternate outlets in Casper, Wyoming.

North America E&P--Exploration

In September 2015, we announced our intention to scale back our conventional exploration program. Our 2016 Capital Program includes $15 million for conventional exploration. No conventional exploration wells are planned in 2016. Our Capital Program is limited to existing commitments in the Gulf of Mexico. We continue to evaluate options for utilization of our remaining commitments on the Maersk Valiant drillship. The rig is currently being operated by our rig share partner, and we anticipate the rig to be available for our use in early 2017.

The Solomon exploration prospect located on Walker Ridge Block 225 was spud during the second quarter of 2015 and reached total depth in the fourth quarter. The well did encounter the lower tertiary target interval. The well was plugged and abandoned, with well costs charged to dry well expense, and the rig was released with no further activity planned on the block. We hold a 58% operated working interest in this prospect.

We hold interests in both operated and non-operated exploration stage oil sand leases in Alberta, Canada, which could be developed using in-situ methods of extraction. These leases cover approximately 142,000 gross (54,000 net) acres in four project areas: Namur, in which we hold a 70% operated interest; Birchwood, in which we hold a 100% operated interest; Ells River, in which we hold a 20% non-operated interest; and Saleski in which we hold a 33% non-operated interest. During 2015, in connection with our decision to scale back our conventional exploration program, and also after further evaluation of the estimated recoverable resources and our development plans at Birchwood, Ells River and Namur, we impaired the remaining net book values of these in-situ properties.

International E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in E.G., Gabon, the Kurdistan Region of Iraq, Libya and the U.K. We include the results of our natural gas liquefaction operations and methanol production operations in E.G. in our International E&P segment. The following table provides net sales volumes for our significant operational areas within this segment:

Net Sales Volumes	2015	Increase (Decrease)	2014	Increase (Decrease)	2013
Equivalent Barrels (mboed)					
Equatorial Guinea	97	(7)%	104	(3)%	107
United Kingdom [(a)]	19	19%	16	(20)%	20
Libya	—	(100)%	7	(75)%	28
Total International E&P (mboed)	116	(9)%	127	(18)%	155
Net Sales Volumes of Equity Method Investees					
LNG (mtd)	5,884	(10)%	6,535	—%	6,548
Methanol (mtd)	937	(14)%	1,092	(13)%	1,249

[(a)] Includes natural gas acquired for injection and subsequent resale of 8 mmcfd, 6 mmcfd and 7 mmcfd for 2015, 2014, and 2013.

Africa

Equatorial Guinea – Production – We own a 63% operated working interest under a PSC in the Alba field which is offshore E.G. Operational availability from our company-operated facilities averaged approximately 97% in 2015. In the third quarter of 2015, production was increased as the Alba C21 development well came online with higher than expected liquid yields, in combination with a successful well intervention program on five existing Alba wells. In January 2016, we completed the installation of an offshore compression platform which is expected to start up mid-2016 following completion of hookup and commissioning activities. The compression project was designed to maintain the production plateau two additional years and extend field life up to eight years.

Equatorial Guinea – Gas Processing – We own a 52% 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 remaining dry natural gas in its operations.

We also own 60% of EGHoldings and 45% of AMPCO, both of which are accounted for as equity method investments. EGHoldings operates an LNG production facility and AMPCO operates a methanol plant, both located on Bioko Island. These facilities allow us to monetize natural gas reserves from the Alba field.

EGHoldings' 3.7 mmta LNG production facility sells LNG under a 3.4 mmta, or 460 mmcfd, sales and purchase agreement through 2023. The purchaser under the agreement takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index. Gross sales of LNG from this production facility totaled 3.6 mmta in 2015.

AMPCO had gross sales totaling 760 mt in 2015. Production from the plant is used to supply customers in Europe and the U.S.

Libya – We hold a 16% non-operated working interest in the Waha concessions, which encompass almost 13 million gross acres located in the Sirte Basin of eastern Libya, where civil and political unrest continues to interrupt our production operations. Operations were interrupted in mid-2013 as a result of the shutdown of the Es Sider crude oil terminal, and although temporarily re-opened during the second half of 2014, production remains shut-in through early 2016. Considerable uncertainty remains around the timing of future production and sales levels. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. See Item 8. Financial Statements and Supplementary Data – Note 12 to the consolidated financial statements for additional information about our Libya operations.

Other International

United Kingdom – 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% working interest in the South, Central, North and West Brae fields and a 39% 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 platforms, respectively. The East Brae platform also hosts the nearby Braemar field in which we have a 28% working interest. During the second quarter of 2015, we completed the final three wells of a five-well Brae infill drilling program that began in 2014.

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 31 third-party fields are contracted to use the Brae system and 72 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 working interest owners of the Brae area producing assets collectively own a 50% non-operated interest in the 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 0.3 bcf per day of third-party natural gas.

We own non-operated working interests in the Foinaven area complex, consisting of a 28% working interest in the main Foinaven field, a 47% working interest in East Foinaven and a 20% working interest in the T35 and T25 fields. The export of Foinaven liquid hydrocarbons is via shuttle tanker from an FPSO to market. All natural gas sales are to the non-operated Magnus platform for use as injection gas.

Kurdistan Region of Iraq – In aggregate, we have approximately 109,000 net acres in the Kurdistan Region of Iraq. We have a 45% operated working interest in the Harir block located northeast of Erbil. We also have non-operated interests in two blocks located north-northwest of Erbil: Atrush with 15% working interest and Sarsang with 20% working interest.

On the non-operated Atrush block, following the successful appraisal program and a declaration of commerciality, the Kurdistan Ministry of Natural Resources approved a plan for field development in September 2013. The development project consists of drilling four production wells and constructing a central processing facility in Phase 1 which provides for a 25-year production period. We expect first production in late 2016 with estimated initial gross production of approximately 30 mbbld of oil. Subject to further drilling and testing results, and partner and government approvals, a potential Phase 2 development could add an additional gross 30 mbbld facility.

On the non-operated Sarsang block, the Swara Tika discovery was declared commercial in May 2014 and a field development plan was filed in June 2014. The plan was approved by the Kurdistan Ministry of Natural Resources in the fourth quarter of 2015. The first producing well came online in 2014 and the second producing well came online in December 2015. In 2016, an additional well is planned to come on-line. As the development plan progresses, we expect to increase production after 2016.

International E&P Exploration

In September 2015, we announced our intention to scale back our conventional exploration program. Our 2016 Capital Program includes $16 million for conventional exploration. No conventional exploration wells are planned in 2016. Our Capital Program is limited to existing commitments in Gabon.

Equatorial Guinea – Exploration – We hold a 63% operated working interest in the Deep Luba discovery on the Alba Block and an 80% operated working interest in the Corona well on Block D. We plan to develop Block D through a unitization with the Alba field. Negotiations have been substantially completed and approval is expected in 2016. We also have an 80% operated working interest in exploratory Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field.

Gabon – Exploration – We hold a 21.25% non-operated working interest in the Diaba License G4-223 and its related permit offshore Gabon, which covers approximately 2.2 million gross (477,000 net) acres. Multiple additional pre-salt prospects have been identified on this License.

In August 2014, we signed an exploration and production sharing contract for Gabon offshore Block G13, which was subsequently re-named Tchicuate. The block, which is located in the pre-salt play offshore Gabon, encompasses 277,000 acres. The seismic program was completed during 2015 and processing will occur through 2016. We hold a 100% participating interest and operatorship in the block. In the event of development, the Republic of Gabon will assume a 20% financed interest in the contract upon commencement of production. The State holds additional rights to participate in the block in the future as a co-investor.

Kurdistan Region of Iraq – During 2015, in connection with our decision to scale back our conventional exploration program, we impaired our investment in the operated Harir block.

International E&P Disposition

In the third quarter of 2015, we entered into an agreement to sell our East Africa exploration acreage in Ethiopia and Kenya. The Kenya transaction closed in February 2016 and the Ethiopia transaction is expected to close during the first quarter of 2016. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for additional information about this disposition.

Oil Sands Mining Segment

We hold a 20% non-operated interest in the AOSP, an oil sands mining and upgrading joint venture located in Alberta, Canada. Other JV partners include Shell Canada Limited with a 60% ownership interest and Chevron Canada Limited with a 20% ownership interest. Shell Canada Limited operates the joint venture, which produces bitumen from oil sands deposits in the Athabasca region utilizing mining techniques and upgrades the bitumen into 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) barrels of bitumen per day. The 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 a series of primary crushers and rotary breakers for particle size reduction. The particles are combined with hot water to create slurry. The slurry is hydro-transported to a primary separation vessel 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 AOSP's Scotford upgrader is located at Fort Saskatchewan, northeast of Edmonton, Alberta. 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 oils 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.

As of December 31, 2015, we own or have rights to participate in developed and undeveloped surface mineable leases totaling approximately 159,000 gross (32,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta. Synthetic crude oil sales volumes for 2015 averaged 53 mbbld and net-of-royalty production was 45 mbbld.

The operating cost structure of our Oil Sands Mining 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. As average price realizations are typically at a discount to WTI, the fixed operating cost structure for Oil Sands Mining will not fully track the price realization. Significant cost improvement efforts were employed in 2015 resulting in a material reduction to the production cost structure. See Item 7. Consolidated Results of Operations: 2015 compared to 2014 for additional detail on production expenses.

The governments of Alberta and Canada agreed to partially fund Quest CCS. Construction began in 2012 and was completed in February 2015. Government funding commenced in 2012 and continued as milestones were achieved during the development, construction and operating phases of the project. Quest CCS was successfully completed and commissioned in the fourth quarter of 2015.

Productive and Drilling Wells

For our North America E&P and International E&P segments, the following table sets forth gross and net productive wells and service wells as of December 31, 2015, 2014 and 2013 and drilling wells as of December 31, 2015.

	Productive Wells[(a)]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2015								
U.S.	7,198	2,878	1,796	750	2,727	747	29	12
E.G.	—	—	17	11	2	1	—	—
Other Africa	1,071	175	7	1	94	16	4	1
Total Africa	1,071	175	24	12	96	17	4	1
Other International	59	21	39	16	24	8	1	—
Total	8,328	3,074	1,859	778	2,847	772	34	13
2014								
U.S.	7,058	2,919	2,246	1,023	2,638	760		
E.G.	—	—	16	11	2	1		
Other Africa	1,071	175	7	1	94	16		
Total Africa	1,071	175	23	12	96	17		
Other International	55	20	39	16	24	8		
Total	8,184	3,114	2,308	1,051	2,758	785		
2013								
U.S.	6,632	2,568	2,763	1,482	2,349	744		
E.G.	—	—	16	11	2	1		
Other Africa	1,064	174	7	1	94	16		
Total Africa	1,064	174	23	12	96	17		
Other International	56	21	40	16	25	9		
Total	7,752	2,763	2,826	1,510	2,470	770		

(a) Of the gross productive wells, wells with multiple completions operated by us totaled 12, 31 and 31 as of December 31, 2015, 2014 and 2013. Information on wells with multiple completions operated by others is unavailable to us.

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Drilling Activity

For our North America E&P and International E&P segments, 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				
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	Total
Year Ended December 31, 2015									
U.S.	135	36	11	182	49	48	1	98	280
E.G.	—	1	—	1	—	—	1	1	2
Other Africa	—	—	—	—	—	—	—	—	—
Total Africa	—	1	—	1	—	—	1	1	2
Other International	1	—	—	1	—	—	—	—	1
Total	136	37	11	184	49	48	2	99	283
Year Ended December 31, 2014									
U.S.	253	43	1	297	49	19	4	72	369
E.G.	—	—	—	—	—	—	1	1	1
Other Africa	1	—	—	1	—	—	—	—	1
Total Africa	1	—	—	1	—	—	1	1	2
Other International	1	—	—	1	—	—	—	—	1
Total	255	43	1	299	49	19	5	73	372
Year Ended December 31, 2013									
U.S.	237	20	—	257	73	13	3	89	346
E.G.	—	—	—	—	—	—	—	—	—
Other Africa	4	—	—	4	1	—	2	3	7
Total Africa	4	—	—	4	1	—	2	3	7
Other International	—	—	—	—	—	—	3	3	3
Total	241	20	—	261	74	13	8	95	356

Acreage

We believe we have satisfactory title to our North America E&P and International E&P 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 acreage held in our North America E&P and International E&P segments as of December 31, 2015.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,323	1,035	801	638	2,124	1,673
Canada	—	—	142	54	142	54
Total North America	1,323	1,035	943	692	2,266	1,727
E.G.	45	29	183	164	228	193
Other Africa	12,909	2,108	26,145	9,612	39,054	11,720
Total Africa	12,954	2,137	26,328	9,776	39,282	11,913
Other International	90	32	345	110	435	142
Total	14,367	3,204	27,616	10,578	41,983	13,782

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 certain of these licenses and concession areas or retain leases through operational or administrative actions; however, the majority of the undeveloped acres associated with Other Africa as listed in the table below pertains to our licenses in Ethiopia and Kenya, for which we executed agreements in 2015 to sell. The Kenya transaction closed in February 2016 and the Ethiopia transaction is expected to close in the first quarter of 2016. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for additional information about this disposition.

	Net Undeveloped Acres Expiring Year Ended December 31,		
(In thousands)	2016	2017	2018
U.S.	68	89	128
E.G.	—	92	36
Other Africa	189	4,352	854
Total Africa	189	4,444	890
Other International	—	—	—
Total	257	4,533	1,018

Reserves

Estimated Reserve Quantities

Reserves are disclosed by continent and by country if the proved reserves related to any geographic area, on an oil equivalent barrel basis, represent 15% or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent or a continent. Other International ("Other Int'l"), includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our East Texas/North Louisiana/Wilburton assets in the third quarter of 2015 and part of our Gulf of Mexico business in the fourth quarter of 2015. Additionally, we closed the sale of our Angola assets and our Norway business in 2014, and both are represented as discontinued operations ("Disc Ops") for periods presented. Approximately 77% of our proved reserves are located in OECD countries.

Our December 31, 2015 proved reserves were calculated using the unweighted average of closing prices nearest to the first day of each month within the 12-month period ("SEC pricing"). The table below provides the 2015 SEC pricing of benchmark prices as well as the unweighted average for the first two months of 2016:

	SEC Pricing 2015	2-month Average 2016
WTI Crude oil	$50.28	$34.19
Henry Hub natural gas	$2.59	$2.28
Brent crude oil	$54.25	$34.86
Natural gas liquids	$17.32	$12.87

When determining the December 31, 2015 proved reserves for each property, the 2015 SEC prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

Beginning in the second half of 2014, the crude oil and natural gas benchmarks began to decline and these declines continued through 2015 and into 2016. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves.

Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing the reserves as of the end of the year. The decline in commodity prices prompted a concerted effort to reduce the costs of developing and producing reserves. Therefore, the impact of sustained reduced commodity prices on future cash flows will be partially offset by the resulting lower costs to develop and produce reserves.

A sustained period of lower commodity prices could also result in additional decreases to our near term capital program and deferrals of investment until prices improve. A shifting of capital expenditures into future periods beyond five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. See Item 1A. Risk Factors for a further discussion of how a substantial extended decline in commodity prices could impact us.

As of December 31, 2015, total proved reserves declined 35 mmboe, primarily due to negative revisions in the U.S. totaling 173 mmboe largely a result of reductions to our capital development program which deferred proved undeveloped reserves beyond the 5-year plan, as well as routine production. This decline was partially offset by increased reserves from the drilling programs in our U.S. unconventional shale plays totaling 246 mmboe as well as a positive revision of 67 mmboe in OSM. The OSM revision was a consequence of technical reevaluation and lower royalty percentages due to lower realized prices. Royalties paid in Canada are on a sliding scale; as the sales price of our synthetic crude oil decreases, our royalty rate decreases. See Item 8. Financial Statements and Supplementary Data - Supplementary Information on Oil and Gas Producing Activities for more information.

The following tables set forth estimated quantities of our proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves based upon an SEC pricing for periods ended December 31, 2015, 2014 and 2013.

	North America			Africa						
December 31, 2015	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate (mmbbl)	327	—	327	25	173	198	16	541	—	541
Natural gas liquids (mmbbl)	92	—	92	12	—	12	—	104	—	104
Natural gas (bcf)	640	—	640	552	94	646	11	1,297	—	1,297
Synthetic crude oil (mmbbl)	—	698	698	—	—	—	—	698	—	698
Total proved developed reserves (mmboe)	526	698	1,224	129	189	318	18	1,560	—	1,560
Proved Undeveloped Reserves										
Crude oil and condensate (mmbbl)	253	—	253	27	28	55	6	314	—	314
Natural gas liquids (mmbbl)	80	—	80	16	—	16	—	96	—	96
Natural gas (bcf)	511	—	511	538	112	650	4	1,165	—	1,165
Synthetic crude oil (mmbbl)	—	—	—	—	—	—	—	—	—	—
Total proved undeveloped reserves (mmboe)	418	—	418	132	46	178	7	603	—	603
Total Proved Reserves										
Crude oil and condensate (mmbbl)	580	—	580	52	201	253	22	855	—	855
Natural gas liquids (mmbbl)	172	—	172	28	—	28	—	200	—	200
Natural gas (bcf)	1,151	—	1,151	1,090	206	1,296	15	2,462	—	2,462
Synthetic crude oil (mmbbl)	—	698	698	—	—	—	—	698	—	698
Total proved reserves (mmboe)	944	698	1,642	261	235	496	25	2,163	—	2,163

	North America			Africa						
December 31, 2014	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate (mmbbl)	294	—	294	30	175	205	19	518	—	518
Natural gas liquids (mmbbl)	68	—	68	15	—	15	—	83	—	83
Natural gas (bcf)	575	—	575	664	94	758	17	1,350	—	1,350
Synthetic crude oil (mmbbl)	—	644	644	—	—	—	—	644	—	644
Total proved developed reserves (mmboe)	458	644	1,102	155	191	346	22	1,470	—	1,470
Proved Undeveloped Reserves										
Crude oil and condensate (mmbbl)	340	—	340	27	33	60	10	410	—	410
Natural gas liquids (mmbbl)	93	—	93	15	—	15	1	109	—	109
Natural gas (bcf)	569	—	569	541	115	656	5	1,230	—	1,230
Synthetic crude oil (mmbbl)	—	4	4	—	—	—	—	4	—	4
Total proved undeveloped reserves (mmboe)	528	4	532	133	52	185	11	728	—	728
Total Proved Reserves										
Crude oil and condensate (mmbbl)	634	—	634	57	208	265	29	928	—	928
Natural gas liquids (mmbbl)	161	—	161	30	—	30	1	192	—	192
Natural gas (bcf)	1,144	—	1,144	1,205	209	1,414	22	2,580	—	2,580
Synthetic crude oil (mmbbl)	—	648	648	—	—	—	—	648	—	648
Total proved reserves (mmboe)	986	648	1,634	288	243	531	33	2,198	—	2,198

December 31, 2013	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate (mmbbl)	241	—	241	37	176	213	19	473	77	550
Natural gas liquids (mmbbl)	51	—	51	18	—	18	1	70	—	70
Natural gas (bcf)	540	—	540	823	95	918	21	1,479	20	1,499
Synthetic crude oil (mmbbl)	—	674	674	—	—	—	—	674	—	674
Total proved developed reserves (mmboe)	382	674	1,056	193	192	385	23	1,464	80	1,544
Proved Undeveloped Reserves										
Crude oil and condensate (mmbbl)	256	—	256	27	39	66	6	328	14	342
Natural gas liquids (mmbbl)	68	—	68	16	—	16	—	84	—	84
Natural gas (bcf)	485	—	485	497	110	607	7	1,099	73	1,172
Synthetic crude oil (mmbbl)	—	6	6	—	—	—	—	6	—	6
Total proved undeveloped reserves (mmboe)	405	6	411	125	57	182	8	601	26	627
Total Proved Reserves										
Crude oil and condensate (mmbbl)	497	—	497	64	215	279	25	801	91	892
Natural gas liquids (mmbbl)	119	—	119	34	—	34	1	154	—	154
Natural gas (bcf)	1,025	—	1,025	1,320	205	1,525	28	2,578	93	2,671
Synthetic crude oil (mmbbl)	—	680	680	—	—	—	—	680	—	680
Total proved reserves (mmboe)	787	680	1,467	318	249	567	31	2,065	106	2,171

Preparation of Reserve Estimates

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Crude oil and condensate, NGLs, 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 his staff of Reserve Coordinators. Crude oil and condensate, NGLs and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QREs"). QREs are engineers or geoscientists who hold at least 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 QRE training course. All QREs must complete a QRE refresher course at least once every three years. Our Corporate Reserves group screens all fields with net proved reserves of 20 mmboe or greater, every year, to determine if a field review is required. Any change to proved reserve estimates in excess of 1 mmboe on a total field basis, within a single month, must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Vice President, Technology and Innovation, has a Bachelor of Science degree in petroleum engineering and is a registered Professional Engineer in the State of Texas. In his 28 years with Marathon Oil, he has held numerous engineering and management positions, including managing our OSM segment. He is a member of the Society of Petroleum Engineers ("SPE") and a former member of the Petroleum Engineering Advisory Council for the University of Texas at Austin.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants ("GLJ") of Calgary, Alberta, Canada, third-party consultants. Their reports for all years are filed as exhibits to this Annual Report on Form 10-K. The individual responsible for the estimates of our synthetic crude oil reserves has 15 years of experience in petroleum engineering, has conducted surface mineable oil sands evaluations since 2009 and is a registered Practicing Professional Engineer in the Province of Alberta.

Audits of Estimates

We engage third-party consultants to provide, at a minimum, independent estimates for fields that comprise 80% of our total proved reserves over a rolling four-year period. We exceeded this percentage for the four-year period ended December 31, 2015, with 82% of our total proved reserves independently audited. We have established a tolerance level of +/- 10% such that initial estimates by the third-party consultants for each field are accepted if they are within 10% of our internal estimates. Should the third-party consultants' initial analysis fail to reach our tolerance level, both parties re-examine the information provided, request additional data and refine their analysis, if appropriate. In the very limited instances where differences outside the 10% tolerance cannot be resolved by year end, a plan to resolve the difference is developed and executive management consent is obtained. The audit process did not result in any significant changes to our reserve estimates for 2015, 2014 or 2013.

During 2015, 2014 and 2013, Netherland, Sewell & Associates, Inc. ("NSAI") prepared a certification of the prior year's reserves for the Alba field in E.G. The NSAI summary reports are filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have multiple years of industry experience, having worked for large, international oil and gas companies before joining NSAI. The senior technical advisor has over 35 years of practical experience in petroleum geosciences, with over 15 years experience in the estimation and evaluation of reserves. The second team member has over 10 years of practical experience in petroleum engineering, with over five years experience in the estimation and evaluation of reserves. Both are registered Professional Engineers in the State of Texas.

Ryder Scott Company ("Ryder Scott") also performed audits of the prior years' reserves of several of our fields in 2015, 2014 and 2013. Their summary reports 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 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, 2015, 603 mmboe of proved undeveloped reserves were reported, a decrease of 125 mmboe from December 31, 2014. The following table shows changes in total proved undeveloped reserves for 2015:

(mmboe)	
Beginning of year	728
Revisions of previous estimates	(223)
Improved recovery	1
Purchases of reserves in place	1
Extensions, discoveries, and other additions	175
Dispositions	—
Transfers to proved developed	(79)
End of year	603

The revisions to previous estimates were largely due to a result of reductions to our capital development program which deferred proved undeveloped reserves beyond the 5-year plan. A total of 139 mmboe was booked as extensions, discoveries or other additions and revisions due to the application of reliable technology. Technologies included statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, reservoir simulation and volumetric analysis. The observed statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved developed locations establish the reasonable certainty criteria required for booking proved reserves.

Transfers from proved undeveloped to proved developed reserves included 47 mmboe in the Eagle Ford, 14 mmboe in the Bakken and 5 mmboe in the Oklahoma Resource Basins due to development drilling and completions.

Costs incurred in 2015, 2014 and 2013 relating to the development of proved undeveloped reserves were $1,415 million, $3,149 million and $2,536 million.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as large development projects which take more than five years to complete, or the timing of when additional gas compression is needed. Of the 603 mmboe of proved undeveloped reserves at December 31, 2015, 26% 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. During 2012, the compression project received the approval of the E.G. government, fabrication of the new platform began in 2013 and installation of the platform at the Alba Field occurred in January 2016. Commissioning is currently underway, with first production expected by mid-2016.

Proved undeveloped reserves for the North Gialo development, located in the Libyan Sahara desert, were booked for the first time in 2010. This development is being executed by the operator and encompasses a multi-year 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 leads to an expected project execution time frame of more than five years from the time the reserves were initially booked. Interruptions associated with the civil and political unrest have also extended the project duration. Operations were interrupted in mid-2013 as a result of the shutdown of the Es Sider crude oil terminal, and although temporarily re-opened during the second half of 2014, production remains shut-in through early 2016. The operator is committed to the project's completion and continues to assign resources in order to execute the project.

Our conversion rate for proved undeveloped reserves to proved developed reserves for 2015 was 11%. However, excluding the aforementioned long-term projects in E.G. and Libya, our 2015 conversion rate would be 15%. Furthermore, our

5-year annual conversion rate (2011-2015) averaged 21% and would be 32%, excluding the long-term projects in E.G. and Libya.

All proved undeveloped reserve drilling locations are scheduled to be drilled prior to the end of 2020. As of December 31, 2015, future development costs estimated to be required for the development of proved undeveloped crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves for the years 2016 through 2020 are projected to be $630 million, $859 million, $1,389 million, $1,764 million and $986 million.

Net Production Sold

	North America			Africa					
	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
Year Ended December 31,									
2015									
Crude and condensate (mbbld)[a]	171	—	171	19	—	19	14	—	204
Natural gas liquids (mbbld)	39	—	39	10	—	10	—	—	49
Natural gas (mmcfd)[b]	351	—	351	410	—	410	21	—	782
Synthetic crude oil (mbbld)[c]	—	45	45	—	—	—	—	—	45
Total production sold (mboed)	269	45	314	97	—	97	18	—	429
2014									
Crude and condensate (mbbld)[a]	157	—	157	21	7	28	11	48	244
Natural gas liquids (mbbld)	29	—	29	10	—	10	—	—	39
Natural gas (mmcfd)[b]	310	—	310	439	1	440	21	37	808
Synthetic crude oil (mbbld)[c]	—	41	41	—	—	—	—	—	41
Total production sold (mboed)	238	41	279	104	7	111	15	54	459
2013									
Crude and condensate (mbbld)[a]	126	—	126	23	24	47	14	81	268
Natural gas liquids (mbbld)	23	—	23	11	—	11	1	—	35
Natural gas (mmcfd)[b]	312	—	312	442	22	464	25	51	852
Synthetic crude oil (mbbld)[c]	—	42	42	—	—	—	—	—	42
Total production sold (mboed)	201	42	243	107	27	134	20	89	486

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

(b) Excludes volumes acquired from third parties for injection and subsequent resale.

(c) Upgraded bitumen excluding blendstocks.

Average Sales Price per Unit

	North America			Africa					
(Dollars per unit)	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
2015									
Crude and condensate (bbl)	$43.50	$—	$43.50	$42.83	$—	$42.83	$53.91	$—	$44.14
Natural gas liquids (bbl)	13.37	—	13.37	1.00 [a]	—	1.00	32.53	—	11.16
Natural gas (mcf)	2.66	—	2.66	0.24 [a]	—	0.24	6.85	—	1.50
Synthetic crude oil (bbl)	—	40.13	40.13	—	—	—	—	—	40.13
2014									
Crude and condensate (bbl)	$85.25	$—	$85.25	$81.01	$94.70	$84.48	$94.31	$109.80	$90.37
Natural gas liquids (bbl)	33.42	—	33.42	1.00 [a]	—	1.00	67.73	—	25.25
Natural gas (mcf)	4.57	—	4.57	0.24 [a]	3.11	0.25	8.27	9.94	2.55
Synthetic crude oil (bbl)	—	83.35	83.35	—	—	—	—	—	83.35
2013									
Crude and condensate (bbl)	$94.19	$—	$94.19	$90.62	$122.92	$107.31	$110.76	$112.36	$102.81
Natural gas liquids (bbl)	35.12	—	35.12	1.00 [a]	—	1.00	72.14	—	24.78

Natural gas (mcf)	3.84	—	3.84	0.24 [(a)]	5.44	0.49	10.64	13.01	2.75
Synthetic crude oil (bbl)	—	87.51	87.51	—	—	—	—	—	87.51

(a) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and/or EGHoldings, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P Segment.

Average Production Cost per Unit[(a)]

	North America			Africa					
(Dollars per boe)	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
2015	$10.65	$38.42	$14.69	$2.37	N.M.	$3.23	$27.23	$—	$12.62
2014	13.34	46.63	18.73	4.03	N.M.	5.72	47.06	8.92	15.37
2013	13.60	55.42	20.79	2.88	7.40	3.80	38.87	8.24	14.51

(a) Production, severance and property taxes are excluded; however, shipping and handling as well as other operating expenses are included in the production costs used in this calculation. See Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities - Results of Operations for Oil and Gas Production Activities for more information regarding production costs.

N.M. Not meaningful information due to limited sales.

Marketing and Midstream

Our reportable operating segments include activities related to the marketing and transportation of substantially all of our liquid hydrocarbon, synthetic crude oil and natural gas production. These activities include the transportation of production to market centers, the sale of commodities to third parties and the storage of production. We balance our various sales, storage and transportation positions in order to aggregate volumes to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Such activities can include the purchase of commodities from third parties for resale.

As discussed previously, we currently own and operate gathering systems and other midstream assets in some of our production areas. We continue to evaluate midstream infrastructure investments in connection with our development plans.

Delivery Commitments

We have committed to deliver quantities of crude oil and synthetic crude oil, natural gas liquids and natural gas to customers under a variety of contracts. As of December 31, 2015, those contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to liquid hydrocarbon production in the Eagle Ford and Bakken, and OSM synthetic crude oil production. Eagle Ford liquid hydrocarbon production sales commitments range from a minimum of 128 mbbld in 2016, decreasing to 51 mbbld through 2020. Bakken liquid hydrocarbon production sales commitments range from 10 mbbld to 30 mbbld from 2016 through 2026. Synthetic crude oil production sales commitments are 14 mbbld in 2016 and 10 mbbld in 2017. Eagle Ford natural gas production sales commitments range from a minimum of 210 mmbtu in 2016, decreasing to 46 mmbtu through 2022.

Our current production rates, forecasts and proved reserves are sufficient to meet these commitments. All of these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate. Certain volumetric requirements can also be met through purchases of third-party volumes.

In addition to the sales contracts discussed above, we have entered into numerous agreements for transportation and processing of our equity production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms.

Competition and Market Conditions

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. 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 crude oil for the sale of our synthetic crude oil to refineries primarily in North America. Because not all refineries are able to process or refine synthetic crude oil in significant volumes, sufficient market demand may not 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 for liquid hydrocarbons and natural gas, as well as changes in competitive conditions in the markets we serve. Generally, results from oil and gas production and OSM operations benefit from higher liquid hydrocarbons and natural gas 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 at the national, state and local levels. Major U.S. federal statutes include, but are not limited to, the Occupational Safety and Health Act ("OSHA") with respect to the protection of the 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. Other countries in which we operate have their own laws dealing with similar matters.

These laws and their implementing regulations and other similar state and local laws and rules can impose certain operational controls for minimization of pollution, recordkeeping, monitoring and reporting requirements or other operational or siting constraints on our business, result in costs to remediate releases of regulated substances, including crude oil, into the environment, or require costs to remediate sites to which we sent regulated substances for disposal. In some cases, these laws can impose strict 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. We have incurred and will continue to incur 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.

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 laws and regulations can only be broadly appraised until their implementation becomes more defined.

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 and Climate Change

The EPA finalized a more stringent National Ambient Air Quality Standard ("NAAQS") for ozone in October 2015. This more stringent ozone NAAQS could result in additional areas being designated as non-attainment, including areas in which we operate, which may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with this revised regulation, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented. The EPA's final rule has been judicially challenged by both industry and other interested parties, and the outcome of this litigation may also impact implementation and revisions to the rule.

In September 2015, the EPA published a suite of proposed rules specifically targeting methane emissions from the oil and gas industry, aggregation of air emissions sources and minor source permitting for operations on tribal lands. These rules are expected to be finalized in 2016. If we are unable to comply with the final terms of these regulations, we could be required to forego construction, modification or certain operations. These regulations may also increase compliance costs for some facilities we own or operate, and result in administrative, civil and/or criminal penalties for non-compliance.

In 2010, the EPA promulgated rules that require us to monitor and submit an annual report on our greenhouse gas emissions. Further, state, national and international requirements to reduce greenhouse emissions are being proposed and in some cases promulgated (see discussion above regarding proposed regulation of methane emissions from the oil and gas industry by the EPA). 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.

In January 2016, the Bureau of Land Management ("BLM") proposed a rule to further restrict venting and/or flaring of gas from facilities subject to BLM jurisdiction, and to modify certain royalty requirements. If the rule is finalized as proposed, it could result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities. If we are unable to comply with the final terms of these regulations, we could be required to forego certain operations. These regulations may also result in administrative, civil and/or criminal penalties for non-compliance.

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. Our business uses this technique extensively throughout our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Federal, state and local-level laws or regulations targeting various aspects of the hydraulic fracturing process are being considered, or have been proposed or implemented. For example, the U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process, and may be expected to do so in future legislative sessions. Further, various state and local-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 to such legislative and regulatory proposals, there are also a number of studies and initiatives underway that may lead to additional proposals in the future, such as the EPA research study on the potential effects that hydraulic fracturing may have on water quality and public health. In 2015 the BLM issued a rule governing certain hydraulic fracturing practices on lands within their jurisdiction. While this rule has been stayed nationwide by court ruling, further findings by the court could result in additional changes to this new rule.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local 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.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. Some state regulatory agencies have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed including recent negligence suits and a RCRA citizen suit in Oklahoma alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells and hydraulic fracturing. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding induced seismicity 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.

Transportation

A number of state and federal rules apply to the transportation of liquid hydrocarbons. In 2014, the U.S. Department of Transportation ("DOT") finalized a rule relating to testing and classification of liquid hydrocarbons and imposing additional restrictions on the types of rail cars that may be used in certain types of liquid hydrocarbon service. Although our businesses do not own rail cars and purchasers of our liquid hydrocarbons make arrangements for its transportation, such regulations could increase transportation costs which are passed on to Marathon Oil by liquid hydrocarbon purchasers. In addition, the Pipeline and Hazardous Materials Safety Administration, a sub-agency of DOT, has proposed or announced the intention to propose various rules related to pipeline transportation of natural gas and/or liquid hydrocarbons. Such regulations could increase the regulatory burden on our businesses where we own or operate pipelines or could otherwise increase costs to third parties that are passed on to Marathon Oil.

Water

In 2014, the EPA and the U.S. Army Corps of Engineers published proposed regulations which expand the surface waters that are regulated under the Clean Water Act and its various programs. While these regulations were finalized largely as proposed in 2015, the rule has been stayed by the courts pending a substantive decision on the merits. If this rule is ultimately implemented, the expansion of CWA jurisdiction will result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities.

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. In 2015, sales to Irving Oil and Shell Oil and each of their respective affiliates accounted for approximately 13% and 11% of our total revenues. In 2014, sales to Shell Oil and its affiliates accounted for approximately 10% of our total revenues. In 2013, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 10% of our total 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 2,611 active, full-time employees as of December 31, 2015. 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, 2016, are as follows:

Lee M. Tillman	54	President and Chief Executive Officer
John R. Sult	56	Executive Vice President and Chief Financial Officer
Sylvia J. Kerrigan	50	Executive Vice President, General Counsel and Secretary
Catherine L. Krajicek	54	Vice President—Technology and Innovation
T. Mitch Little	52	Vice President—Conventional
Lance W. Robertson	43	Vice President—Resource Plays
Patrick J. Wagner	51	Vice President, Corporate Development
Gary E. Wilson	54	Vice President, Controller and Chief Accounting Officer

Mr. Tillman was appointed president and chief executive officer in August 2013. Mr. Tillman is also a member of our Board of Directors. Prior to this appointment, Mr. Tillman served as vice president of engineering for ExxonMobil Development Company (a project design and execution company), where he was responsible for all global engineering staff engaged in major project concept selection, front-end design and engineering. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil in Stavanger, Norway. Mr. Tillman began his career in the oil and gas industry at Exxon Corporation in 1989 as a research engineer and has extensive operations management and leadership experience.

Mr. Sult was appointed executive vice president and chief financial officer in September 2013. Prior to joining Marathon Oil, Mr. Sult served as executive vice president and chief financial officer of El Paso Corporation (a natural gas provider) from 2010 through 2012, senior vice president and chief financial officer from 2009 to 2010, and senior vice president, chief accounting officer and controller from 2005 to 2009.

Ms. Kerrigan was appointed executive vice president, general counsel and secretary in October 2012, having served as vice president, general counsel and secretary since November 2009. Prior to these appointments, Ms. Kerrigan served as assistant general counsel since January 2003.

Ms. Krajicek was appointed vice president—technology and innovation in December 2015, having served as vice president, health, environment, safety and security since January 2015. Prior to that, Ms. Krajicek held a number of positions of increasing responsibility with Marathon Oil. Prior to joining the Company in 2007, Ms. Krajicek spent 22 years with Conoco and then ConocoPhillips (a multinational energy corporation), where she held a variety of reservoir engineering and asset management and development management positions for upstream and mid-stream businesses under development, both in the U.S. and internationally.

Mr. Little was appointed vice president—conventional in December 2015, having served as vice president, international and offshore exploration and production operations since September 2013, and as vice president, international production operations since September 2012. Prior to that, 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 since held a number of engineering and management positions of increasing responsibility.

Mr. Robertson was appointed vice president—resource plays in December 2015, having served as vice president, North America production operations since September 2013 and as vice president, Eagle Ford production operations since 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 Company (an independent oil and gas company) in the U.S. and Canada.

Mr. Wagner was appointed vice president—corporate development in April 2014. Prior to joining Marathon Oil, he served as senior vice president, western business unit, for QR Energy LP (an oil and natural gas producer) and the affiliated Quantum Resources Management (a private equity firm), which he joined in early 2012 as vice president, exploitation. Prior to that, Wagner was managing director in Houston for Scotia Waterous, the oil and gas arm of Scotiabank (an international banking services provider), from 2010 to 2012. Before joining Scotia, Wagner was vice president, Gulf of Mexico, for Devon Energy Corp. (an oil and natural gas producer), having joined Devon in 2003 as manager, international exploitation.

Mr. Wilson was appointed vice president, controller and chief accounting officer in October 2014. Prior to joining Marathon Oil, he served in various finance and accounting positions of increasing responsibility at Noble Energy, Inc. (a global exploration and production company) since 2001, including as director corporate accounting from February 2014 through September 2014, director global operations services finance from October 2012 through February 2014, director controls and reporting from April 2011 through September 2012, and international finance manager from September 2009 through March 2011.

Available Information

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

The public may read and copy any materials we file with the SEC at its Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Additionally, we make available free of charge on our website:

- our Code of Business Conduct and Code of Ethics for Senior Financial Officers;
- our Corporate Governance Principles; and

- the charters of our Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee.

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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.

The recent substantial decline in liquid hydrocarbon and natural gas prices has reduced our operating results and cash flows and, if continued, could adversely impact our future rate of growth and the carrying value of our assets.

Prices for crude oil and condensate, NGLs, natural gas and synthetic crude oil fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil and condensate, NGLs, natural gas and synthetic crude oil. Historically, the markets for crude oil and condensate, NGLs, natural gas and synthetic crude oil have been volatile and may continue to be volatile in the future. Beginning in the second half of 2014 and continuing into 2016, prices for WTI and Brent crude oil, Henry Hub natural gas and natural gas liquids have substantially declined. Furthermore, crude oil and natural gas futures prices indicate that these lower prices may persist for the foreseeable future. Many of the factors influencing prices of crude oil and condensate, NGLs, natural gas and synthetic crude oil are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- the cost of exploring for, developing and producing crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- the ability of the members of OPEC to agree to and maintain production controls;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- 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;
- epidemics or pandemics;
- technological advances affecting energy consumption and energy supply;
- 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil are uncertain. The recent substantial declines in commodity prices already have adversely affected our business by:

- reducing the amount of crude oil and condensate, NGLs, natural gas and synthetic crude oil that we can produce economically;
- reducing our revenues, operating income and cash flows;
- causing us to reduce our capital expenditures, and delay or postpone some of our capital projects;
- requiring us to impair the carrying value of our assets;
- reducing the standardized measure of discounted future net cash flows relating to crude oil and condensate, NGLs, natural gas and synthetic crude oil; and
- increasing the costs of obtaining capital, such as equity and short- and long-term debt.

A further prolonged extension of prices at these levels could extend or exacerbate these adverse effects.

A substantial, extended decline in liquid hydrocarbon or natural gas prices could adversely affect the abilities of our counterparties to perform their obligations to us, including abandonment obligations, which could negatively impact our financial results.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, oil sands mining or liquid hydrocarbon or natural gas transportation, with partners and other counterparties in order to share risks associated with those operations. In addition, we market our products to a variety of purchasers. If commodity prices remain at or fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial and other obligations, including abandonment obligations, to us. The inability of our joint venture partners to fund their portion of the costs under our joint venture agreements, or the nonperformance by purchasers, contractors or other counterparties of their obligations to us, could negatively impact our operating results and cash flows.

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 crude oil and condensate, NGLs, 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 reserves.

The proved reserve information included in this Annual Report on Form 10-K has been derived from engineering and geoscience 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, a third-party consulting firm experienced in working with oil sands. Reserves were valued based on SEC pricing for the periods ended December 31, 2015, 2014 and 2013, as well as other conditions in existence at those dates. The table below provides the 2015 SEC pricing for certain benchmark prices as well as the unweighted average for the first two months of 2016:

	SEC Pricing 2015	2-month Average 2016
WTI Crude oil	$50.28	$34.19
Henry Hub natural gas	$2.59	$2.28
Brent crude oil	$54.25	$34.86
Natural gas liquids	$17.32	$12.87

Any significant future price change could have a material effect on the quantity and present value of our proved reserves. To the extent that commodity prices remain at current or lower levels throughout 2016, a portion of our proved reserves could be deemed uneconomic and no longer classified as proved. This could impact both proved developed producing reserves as well as proved undeveloped reserves. If prices remain at the 2-month average depicted above throughout 2016, a material volume of our proved reserves could become uneconomic and would have to be reclassified to non-proved reserve or resource category. Assuming lower SEC pricing in 2016, our OSM proved reserves represent the largest risk to be reclassified to non-proved reserve or resource category. However, any impact of lower SEC pricing will likely be partially offset by continued cost reduction efforts. Also, any volumes reclassified to non-proved reserves could return to proved reserves as commodity prices improve. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and condensate, NGLs, 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 cash flows from our proved crude oil and condensate, NGLs, 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 cash flows from our proved crude oil and condensate, NGLs, 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, 2015, 2014 and 2013, 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% discount factor required by the applicable rules of the SEC to be used to calculate discounted future cash flows 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil are produced. Accordingly, to the extent we are not successful in replacing the crude oil and condensate, NGLs, natural gas and synthetic crude oil 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil in promising areas;
- drilling success;
- the ability to complete long lead-time, capital-intensive projects timely and cost effectively;
- 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 crude oil and condensate, NGLs 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 or 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 capital projects.

We may incur substantial capital expenditures and operating costs as a result of compliance with, and/or 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 and 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 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 clean-ups 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.

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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. Our operations result in greenhouse gas emissions. Currently, various legislative or 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 the European Union. Internationally, the United Nations Framework Convention on Climate Change finalized an agreement among 195 nations at the 21st Conference of the Parties in Paris with an overarching goal of preventing global temperatures from rising more than 2 degrees Celsius. The agreement includes provisions that every country take some action to lower emissions, but there is no legal requirement for how or by what amount emissions should be lowered. The EPA has also proposed regulations targeting methane emissions from the oil and gas industry, which are expected to be finalized in 2016. Finalization of new legislation, regulations or international agreements in the future 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil, and create delays in our obtaining air pollution permits for new or modified facilities.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing, including the operation of injection wells, could result in increased compliance costs, 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. Our business uses this technique extensively throughout our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Federal, state and local-level laws or regulations targeting various aspects of the hydraulic fracturing process are being considered, or have been proposed or implemented. For example, the U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process, and may be expected to do so in future legislative sessions. Further, various state and local-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 to such legislative and regulatory proposals, there are also a number of studies and initiatives underway that may lead to additional proposals in the future, such as the EPA research study on the potential effects that hydraulic fracturing may have on water quality and public health. In 2015 the Bureau of Land Management issued a rule governing certain hydraulic fracturing practices on lands within their jurisdiction. While this rule has been stayed nationwide by court ruling, further findings by the court could result in additional changes to this new rule.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local 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.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. Some state regulatory agencies have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed including recent negligence suits and a RCRA citizen suit in Oklahoma alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells and hydraulic fracturing. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding induced seismicity 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 39% of our liquid hydrocarbon and natural gas sales volumes related to continuing operations in 2015 was derived from production outside the U.S. and 56% of our proved crude oil and condensate, NGLs and natural gas reserves as of December 31, 2015 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 or other armed conflict attendant to doing business within or outside of the U.S. There are many risks associated with operations in countries such as E.G., Ethiopia, Gabon, the Kurdistan Region of Iraq and Libya, and in global markets 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, armed conflict 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.

For the past several years, there have been varying degrees of political instability and public protests, including demonstrations which have been marked by violence and numerous incidences of terrorist acts, 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, or other armed conflict, 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil. 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, including new regulations resulting in higher costs to transport our production by pipeline, rail car, truck or vessel or 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 level of indebtedness may limit our liquidity and financial flexibility.

Our total debt was $7.3 billion as of December 31, 2015. Our indebtedness could have important consequences to our business, including, but not limited to, the following:

- we may be more vulnerable to general adverse economic and industry conditions;

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- our flexibility in planning for, or reacting to, changes in our industry may be limited;
- we may be at a competitive disadvantage as compared to similar companies that have less debt; and
- additional financing in the future for working capital, capital expenditures, acquisitions or development activities, general corporate or other purposes may have higher costs and more restrictive covenants.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness increases the risk that our financial flexibility may deteriorate. Our ability to meet our debt obligations and service our debt depends on future performance. General economic conditions, crude oil and condensate, NGLs, natural gas and synthetic crude oil prices, and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt. See Item 8. Financial Statements and Supplementary Data – Note 17 to the consolidated financial statements for a discussion of debt obligations.

A downgrade in our credit rating, particularly below investment grade, could negatively impact our cost of and ability to access capital, which could adversely affect our business.

We receive debt ratings from the major credit rating agencies in the United States. The credit rating process is contingent upon a number of factors, many of which are beyond our control. A downgrade of our credit ratings, particularly below investment grade, could negatively impact our cost of capital and our ability to access the capital markets, increase the interest rate and fees we pay on our revolving credit facility, and restrict our access to the commercial paper market. We could also be required to post letters of credit or other forms of collateral for certain obligations, which could increase our costs and decrease our liquidity or letter of credit capacity under our unsecured revolving credit facility. Limitations on our ability to access capital could adversely impact the level of our capital spending program, our ability to manage our debt maturities, or our flexibility to react to changing economic and business conditions.

Our commodity price risk management 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.

Our business, like other companies in the oil and gas industry, has become increasingly dependent on digital technologies. Such technologies are integrated into our business operations and used as a part of our liquid hydrocarbon and natural gas production and distribution systems in the U.S. and abroad, including those systems used to transport production to market. Use of the internet and other public networks for communications, services, and storage, including "cloud" computing, exposes users (including our business) to cybersecurity risks. While our information systems and related infrastructure experienced attempted and actual minor breaches of our cybersecurity in the past, we have not suffered any losses or breaches which had a material effect on our business, operations or reputation relating to such attacks; however, there is no assurance that we will not suffer such losses or breaches in the future. As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

Our operations may be adversely affected by pipeline, rail and other transportation capacity constraints.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities, rail cars, trucks and vessels. If any pipelines, rail cars, trucks or vessels become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our crude oil and condensate, NGLs, natural gas and synthetic crude oil, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production. Both the cost and availability of pipelines, rail cars, trucks, or vessels to transport our crude oil could be adversely impacted by new and expected state or federal regulations relating to transportation of crude oil.

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 liquid hydrocarbon 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 liquid hydrocarbon 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 liquid hydrocarbon 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 as oil and gas exploration and production, or oil sands mining, 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 North America E&P and International 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 our products from our facilities. A prolonged disruption in the ability of any pipelines, rail cars, trucks, or vessels to transport our production 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 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 windstorms has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity 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, contract disputes, royalty disputes 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.

Estimated net proved crude oil and condensate, NGLs, 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.

Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2015 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.

As of December 31, 2015, 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 have approximately $4 million accrued to address the clean-up and remediation costs connected with these sites.

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, 2016, there were 37,608 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:

	2015			2014		
(Dollars per share)	High Price	Low Price	Dividends	High Price	Low Price	Dividends
First Quarter	$29.63	$25.47	$0.21	$35.52	$31.81	$0.19
Second Quarter	$31.19	$25.92	$0.21	$40.16	$34.90	$0.19
Third Quarter	$25.79	$14.04	$0.21	$41.69	$37.59	$0.21
Fourth Quarter	$20.18	$12.38	$0.05	$37.13	$24.80	$0.21
Full Year	$31.19	$12.38	$0.68	$41.69	$24.80	$0.80

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

The following table provides information about purchases by Marathon Oil and its affiliated purchaser, during the quarter ended December 31, 2015, 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)
10/01/15 – 10/31/15	46,156		$18.44	—	$1,500,285,529
11/01/15 – 11/30/15	4,179		$18.19	—	$1,500,285,529
12/01/15 – 12/31/15	1,049	(b)	$19.18	—	$1,500,285,529
Total	51,384		$18.44	—	

(a) 51,384 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) Does not include shares 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. On March 9, 2015, the Dividend Reinvestment Plan was terminated. Participants in the Dividend Reinvestment Plan were transferred to Computershare CIP, a Direct Stock Purchase and Dividend Reinvestment Plan, which is sponsored and administered by Computershare Trust Company, N.A.

(c) In January 2006, we announced a $2.0 billion share repurchase program. Our Board of Directors subsequently increased the authorization for repurchases under the program by $500 million in January 2007, by $500 million in May 2007, by $2.0 billion in July 2007, and by $1.2 billion in December 2013, for a total authorized amount of $6.2 billion. The remaining share repurchase authorization as of December 31, 2015 is $1.5 billion. No repurchases were made under the program in 2015.

Item 6. Selected Financial Data

	Year Ended December 31,				
(In millions, except per share data)	2015	2014	2013	2012	2011
Statement of Income Data[a][b]					
Revenues	$5,522	$10,846	$11,325	$11,966	$11,088
Income (loss) from continuing operations	(2,204)	969	931	856	467
Net income (loss)	(2,204)	3,046	1,753	1,582	2,946
Per Share Data[a][b]					
Basic:					
Income (loss) from continuing operations	$(3.26)	$1.42	$1.32	$1.21	$0.66
Net income (loss)	$(3.26)	$4.48	$2.49	$2.24	$4.15
Diluted:					
Income (loss) from continuing operations	$(3.26)	$1.42	$1.31	$1.21	$0.65
Net income (loss)	$(3.26)	$4.46	$2.47	$2.23	$4.13
Statement of Cash Flows Data[b]					
Additions to property, plant and equipment related to continuing operations	$3,476	$5,160	$4,443	$4,361	$2,767
Dividends paid	460	543	508	480	567
Dividends per share	$0.68	$0.80	$0.72	$0.68	$0.80
Balance Sheet Data at December 31[c]					
Total assets	$32,311	$35,983	$35,588	$35,269	$31,344
Total long-term debt, including capitalized leases	7,276	5,295	6,362	6,475	4,647

(a) Includes impairments to producing properties of $412 million, $132 million, $96 million, $371 million and $310 million in 2015, 2014, 2013, 2012 and 2011 and impairments to unproved properties of $964 million, $306 million, $572 million and $227 million in 2015, 2014, 2013 and 2012 (see Item 8. Financial Statements and Supplementary Data – Note 13 to the consolidated financial statements)). Includes a goodwill impairment of $340 million in 2015 related to the N.A. E&P reporting unit. (see Item 8. Financial Statements and Supplementary Data – Note 14 to the consolidated financial statements).

(b) We closed the sale of our Angola assets and our Norway business in 2014 (see Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements); and our downstream business was spun-off in 2011. The applicable periods have been recast to reflect these businesses as discontinued operations.

(c) Prior year periods were adjusted to reflect debt issuance costs as a direct reduction from the associated debt liability in our consolidated balance sheets with the adoption of the debt issuance costs standard in the fourth quarter of 2015. See Note 2 for information.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. The following discussion includes forward-looking statements that involve certain risks and uncertainties. See "Disclosures Regarding Forward-Looking Statements" (immediately prior to Part I) and Item 1A. Risk Factors.

Each of our segments is organized and managed based upon both geographic location and the nature of the products and services it offers:

- North America E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining – 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.

Executive Summary

We were able to increase net sales volumes by 20% in the three core U.S. resource plays despite a significant reduction in capital expenditures caused by the deterioration in commodity prices during 2015. Our focus on cost discipline and efficiencies yielded sustainable savings in both operating expenses and capital costs. We prioritized capital allocation to our domestic unconventional resource plays and scaled back our conventional exploration program. We continued to progress our program of non-core asset sales and realized aggregate net proceeds of $225 million. We ended 2015 with liquidity of $4.2 billion comprised of $1.2 billion of cash and $3.0 billion available through a committed multi-year credit facility. Despite current commodity prices, we believe that we can satisfy operational objectives and capital commitments with the cash and cash equivalents on hand, internally generated cash flow from operations, available borrowing capacity, the flexibility to adjust our Capital Program and our non-core asset disposition program. Our target for non-core asset dispositions is now $750 million to $1 billion, an increase from our previous goal of $500 million.

Significant 2015 operating and financial activities include the following:

- Increased company-wide net sales volumes from continuing operations by 6% to 438 mboed from 415 mboed
  - Net sales volumes from our three U.S. resource plays increased 20% to 218 mboed from 181 mboed
- Maintained focus on cost discipline and efficiencies
  - Reduced our 2015 Capital Program by approximately 50% from the prior year, down to $3 billion, reflecting continued capital discipline and benefits from operating efficiencies
  - Reduced company-wide production expenses per boe in 2015
    - North America E&P - 28% reduction to $7.38 per boe
    - International E&P - 28% reduction to $5.99 per boe
  - Rationalized the workforce during 2015, and expect to generate a future annualized net savings of $160 million from a 20% reduction in workforce
- Active management of liquidity and capital structure
  - At December 31, 2015:
    - Liquidity of $4.2 billion
    - Cash-adjusted debt-to-capital ratio was 25%
  - Issued $2 billion aggregate principal amount of unsecured senior notes, $1 billion of which was used to repay the 0.90% senior notes that matured in November 2015
  - Increased the capacity of the revolving credit facility to $3.0 billion while also extending the maturity date to May 2020
  - Repatriated Canadian earnings in a tax efficient manner, providing $250 million of cash available for use in U.S. operations

Reduced the quarterly dividend beginning in the third quarter, from $0.21 per share to $0.05 per share
• Portfolio management activities
We continue to make progress in our non-core asset divestitures, with a goal of $750 million to $1 billion
Closed on the sale of our East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets in August 2015 for net proceeds of approximately $100 million
Closed on the sale of certain Gulf of Mexico properties in December 2015 for net cash proceeds of $111 million

Signed an agreement for the sale of our East Africa exploration acreage in Kenya and Ethiopia; the Kenya transaction closed in February 2016 and Ethiopia is expected to close during the first quarter of 2016.

•Financial results

Loss from continuing operations per diluted share of $3.26 in 2015 as compared to income from continuing operations of $1.42 per diluted share in 2014, reflecting the impact of lower commodity prices

Included in the loss for 2015 are $1.4 billion ($1.7 billion pre-tax) of charges comprised largely of losses and asset impairments resulting from lower forecasted commodity prices, goodwill impairment and changes in our conventional exploration strategy (refer to North America E&P - Exploration and International E&P - Exploration in Item 1. Business)

Recorded non-cash deferred tax expense of $135 million in 2015 related to the increase in Alberta's provincial corporate income tax rate

Operating cash flow provided by continuing operations for 2015 was $1.6 billion, compared to $4.7 billion in 2014, reflecting the lower commodity price environment

Outlook

Commodity prices are the most significant factor impacting our revenues, profitability, operating cash flows and the amount of capital available to reinvest into our business. Commodity prices began declining in the second half of 2014 and continued through 2015 and into 2016. We believe we can manage in this lower commodity price cycle through operational execution, efficiency improvements, cost reductions, capital discipline and portfolio optimization, while continuing to focus on balance sheet protection.

Capital Program

Our Board of Directors approved a Capital Program of $1.4 billion for 2016. We intend to be flexible with respect to our capital allocation decisions in light of this challenged commodity pricing environment. With that in mind, we have engaged in an active program to divest of non-core assets, which together with our anticipated cash flows from operations, plus the savings embedded from the cost reductions we have put in place, should allow us to meet our current Capital Program, operating costs, debt service and dividends. The discipline undertaken as part of a real-time evaluation of our revenues, expenditures, and asset dispositions should allow us to live within our means.

Our Capital Program is broken down by reportable segment in the table below:

(In millions)	2016 Capital Program	Percent of Total	
North America E&P	$1,166	81	%
International E&P	185	13	%
Oil Sands Mining	41	3	%
Segment total	1,392	97	%
Corporate and other	40	3	%
Total Capital Program	$1,432	100	%

North America E&P – Approximately $1.2 billion of our Capital Program is allocated to our three core U.S. resource plays.

Eagle Ford - Approximately $600 million is planned, we expect to average five rigs and bring 124-132 gross-operated wells to sales. Included in Eagle Ford spending is approximately $520 million for drilling and completions. The 2016 drilling program will continue to focus on the co-development of the Lower and Upper Eagle Ford horizons as well as Austin Chalk in the core of the play.

Oklahoma Resource Basins - Spending of approximately $200 million is targeted, we expect to average two rigs which will focus primarily on lease retention in the STACK and delineation of the Meramec, and bring 20-22 gross-operated wells to sales. Spending includes approximately $195 million for drilling and completions, including $55 million for outside-operated activity. We expect to be approximately 70% held by production in the STACK by year end, with SCOOP already 90% held by production.

Bakken - We plan to spend just under $200 million in North Dakota. Drilling activity will average one rig for half of 2016 and bring online 13-15 gross-operated wells. Bakken spending includes approximately $150 million for drilling and completions, including $75 million for outside-operated activity. Facilities and infrastructure spending will be significantly lower than 2015 with the next phase of the water-gathering system scheduled to be complete in the second half of 2016.

International E&P – Approximately $170 million of our Capital Program is dedicated to our international assets, primarily in E.G. and the Kurdistan Region of Iraq. The Alba field compression project in E.G. remains on schedule to start up by mid-year, and will extend plateau production by two years as well as the asset's life by up to eight years.

Approximately $30 million of our Capital Program will be spent on a targeted exploration program impacting both the North America E&P and the International E&P segments. Activity in 2016 is limited to fulfilling existing commitments in the Gulf of Mexico and Gabon, with no operated exploration wells planned.

Oil Sands Mining – We expect to spend $40 million of the Capital Program for sustaining capital projects.

The remainder of our Capital Program consists of Corporate and Other and is expected to total approximately $40 million.

For information about expected exploration and development activities more specific to individual assets, see Item 1. Business.

Production Volumes

We forecast 2016 production available for sale from the combined North America E&P and International E&P segments, excluding Libya, to average 335 to 355 net mboed and the OSM segment to average 40 to 50 net mbbld of synthetic crude oil.

Acquisitions and Dispositions

Excluded from our Capital Program are the impacts of acquisitions and dispositions not previously announced. We continually evaluate ways to optimize our portfolio through acquisitions and divestitures. In connection with our ongoing portfolio management, future decisions to dispose of assets could result in non-cash impairments in the period such decisions are made.

Operations

Our net sales volumes from continuing operations averaged 438 mboed, 415 mboed and 404 mboed for 2015, 2014 and 2013. As liftings from Libya were sporadic during this 3-year period, a more representative comparison is net sales volumes from continuing operations excluding Libya, which was 438 mboed, 408 mboed and 376 mboed for 2015, 2014 and 2013. The continued ramp up of production from our U.S. resource plays has been the most significant contributor to the increases when comparing results excluding Libya, partially offset by decreases from domestic asset sales and normal production declines.

Net Sales Volumes	2015	Increase (Decrease)	2014	Increase (Decrease)	2013
North America E&P (mboed)	269	13 %	238	18 %	201
International E&P (mboed)	116	(9)%	127	(18)%	155
Oil Sands Mining (mbbld) [(a)]	53	6 %	50	4 %	48
Total Continuing Operations (mboed)	438	6 %	415	3 %	404

[(a)] Includes blendstocks.

North America E&P

The following tables provide additional detail regarding net sales volumes, sales mix and operational drilling activity:

Net Sales Volumes	2015	Increase (Decrease)	2014	Increase (Decrease)	2013
Eagle Ford	134	20%	112	38%	81
Oklahoma Resource Basins	25	39%	18	29%	14
Bakken	59	16%	51	31%	39
Other North America[(a)]	51	(11)%	57	(15)%	67
Total North America E&P (mboed)	269	13%	238	18%	201

[(a)] Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013.

Sales Mix - U.S. Resource Plays - 2015	Eagle Ford	Oklahoma Resource Basins	Bakken
Crude oil and condensate	60%	19%	87%
Natural gas liquids	19%	28%	7%
Natural gas	21%	53%	6%

Drilling Activity - U.S. Resource Plays	2015	2014	2013
Gross Operated			
Eagle Ford:			
Wells drilled to total depth	251	360	299
Wells brought to sales	276	310	307
Oklahoma Resource Basins:			
Wells drilled to total depth	21	19	10
Wells brought to sales	20	18	9
Bakken:			
Wells drilled to total depth	35	83	76
Wells brought to sales	56	69	77

North America E&P segment average net sales volumes in 2015 increased 13% when compared to 2014. Net liquid hydrocarbon sales volumes increased 24 mbbld and net natural gas sales volumes increased 41 mmcfd in 2015 primarily reflecting continued growth from our three core U.S. resource plays.

North America E&P segment average net sales volumes in 2014 increased 18% when compared to 2013, primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in our three key U.S. resource plays. This was partially offset by lower natural gas sales volumes, primarily due to the shut-in and exit from Powder River Basin operations.

Refer to the Item 1. Business section for additional detail related to net sales volumes by asset.

International E&P

The following table provides net sales volumes from continuing operations:

Net Sales Volumes	2015	Increase (Decrease)	2014	Increase (Decrease)	2013
Equivalent Barrels (mboed)					
Equatorial Guinea	97	(7)%	104	(3)%	107
United Kingdom[a]	19	19%	16	(20)%	20
Libya	—	(100)%	7	(75)%	28
Total International E&P (mboed)	116	(9)%	127	(18)%	155
Net Sales Volumes of Equity Method Investees					
LNG (mtd)	5,884	(10)%	6,535	—%	6,548
Methanol (mtd)	937	(14)%	1,092	(13)%	1,249

(a) Includes natural gas acquired for injection and subsequent resale of 8 mmcfd, 6 mmcfd and 7 mmcfd for 2015, 2014, and 2013.

International E&P segment average net sales volumes in 2015 decreased 9% when compared to 2014. We did not record any sales from Libya in 2015 as a result of the shutdown of the Es Sider crude oil terminal and ongoing civil unrest. Sales volumes in Equatorial Guinea were lower due to a series of turnarounds and other maintenance activities performed at the Alba field, EG LNG and AMPCO facilities during the year. In the U.K., sales volumes increased as we completed the five-well Brae infill drilling program that began in 2014. The Brae Alpha installation experienced a process pipe failure in December 2015. Repairs are underway and full production is expected to resume in the second quarter of 2016.

International E&P segment average net sales volumes in 2014 decreased 18% when compared to 2013. We had lower sales from Libya in 2014 as a result of the shutdown of the Es Sider crude oil terminal which was temporarily re-opened during the second half of 2014. Excluding Libya, net sales volumes decreased 6%, primarily due to reliability issues and production decline in the U.K. and lower reliability at the non-operated methanol facility in E.G.

Refer to the Item 1. Business section for additional detail related to net sales volumes by asset.

Oil Sands Mining

Our OSM operations consist of a 20% non-operated working interest in the AOSP. Our net synthetic crude oil sales volumes were 53 mbbld in 2015 compared to 50 mbbld in 2014 and 48 mbbld in 2013.

Market Conditions

Oil and gas price declines during 2015 and into 2016 are reflective of robust supply growth from both OPEC and non-OPEC production around the world. The effect of this supply growth on prices was exacerbated by weakening demand growth in emerging markets and OPEC's formal abandonment of production targets in December 2015. Crude oil, natural gas and NGLs benchmark prices are likely to remain volatile based on global supply and demand and declined further subsequent to December 31, 2015 as compared to the average realized prices in the tables below. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Estimates for further discussion of how a further decline in commodity prices could impact us.

North America E&P

The following table presents our average price realizations and the related benchmarks for crude oil, NGLs and natural gas for 2015, 2014 and 2013:

	2015	Decrease	2014	Decrease	2013
Average Price Realizations [(a)]					
Crude Oil and Condensate (per bbl) [(b)]	$43.50	(49)%	$85.25	(9)%	94.19
Natural Gas Liquids (per bbl)	13.37	(60)%	33.42	(5)%	35.12
Total Liquid Hydrocarbons (per bbl)	37.85	(51)%	77.02	(10)%	85.20
Natural Gas (per mcf)	2.66	(42)%	4.57	19%	3.84
Benchmarks					
WTI crude oil average of daily prices (per bbl)	$48.76	(48)%	$92.91	(5)%	98.05
LLS crude oil average of daily prices (per bbl)	52.33	(46)%	96.64	(10)%	107.36
Mont Belvieu NGLs (per bbl) [(c)]	16.94	(48)%	32.52	(4)%	33.78
Henry Hub natural gas settlement date average (per mmbtu)	2.66	(40)%	4.42	21%	3.65

(a) Excludes gains or losses on derivative instruments.

(b) Inclusion of realized gains (losses) on crude oil derivative instruments would have increased (decreased) average liquid hydrocarbon price realizations per barrel by $1.24 and $(0.27) for 2015 and 2013. There were no crude oil derivative instruments for 2014.

(c) Bloomberg Finance LLP: Y-grade Mix NGL of 50% ethane, 25% propane, 10% butane, 5% isobutane and 10% natural gasoline.

Crude oil and condensate – Our crude oil and condensate price realizations may differ from the benchmark due to the quality and location of the product.

Natural gas liquids – The majority of our NGLs volumes are sold at reference to Mont Belvieu prices.

Natural gas – A significant portion of our natural gas production in the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas.

International E&P

The following table presents our average price realizations and the related benchmark for crude oil for 2015, 2014 and 2013:

	2015	Decrease	2014	Decrease	2013
Average Price Realizations					
Crude Oil and Condensate (per bbl)	$47.50	(46)%	$87.23	(19)%	$108.18
Natural Gas Liquids (per bbl)	2.81	14%	2.46	(53)%	5.24
Total Liquid Hydrocarbons (per bbl)	36.67	(47)%	68.98	(24)%	91.04
Natural Gas (per mcf)	0.68	(6)%	0.72	(37)%	1.15
Benchmark					
Brent (Europe) crude oil (per bbl)[(a)]	$52.35	(47)%	$99.02	(9)%	$108.64

(a) Average of monthly prices obtained from EIA website.

Our U.K. liquid hydrocarbon production is generally sold in relation to the Brent crude benchmark. Our production from the Alba field in E.G. is condensate and gas. Condensate is sold at market prices. The Alba Plant extracts NGLs and secondary condensate from gas, leaving dry natural gas. The processed NGLs are sold by Alba Plant at market prices, with our share of its income/loss reflected in Income from equity method investments. The dry natural gas from Alba Plant is supplied to AMPCO and EGHoldings under long-term contracts at fixed prices; therefore, our reported average realized prices for NGLs and natural gas will not fully track market price movements. Because of the location and limited local demand for natural gas in E.G., we consider the prices under the contracts with Alba Plant LLC, EGHoldings and AMPCO to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. EGHoldings and AMPCO process the gas into LNG and methanol, which are sold at market prices, with our share of their income/loss reflected in the Income from equity method investments line item on the Consolidated Statements of Income. Although uncommon, any dry gas not sold is returned offshore and re-injected into the Alba field for later production.

Oil Sands Mining

The Oil Sands Mining segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational reliability or planned unit outages at the mines or upgrader. Sales prices for synthetic crude oil historically tracked movements in the WTI crude oil and the WCS Canadian heavy crude oil benchmarks. The influence of each benchmark can change from period to period based on market dynamics.

The following table presents our average price realizations and the related benchmarks that impacted both our revenues and variable costs for 2015, 2014 and 2013:

	2015	Increase (Decrease)	2014	Increase (Decrease)	2013
Average Price Realizations					
Synthetic Crude Oil (per bbl)	$40.13	(52 %)	$83.35	(5 %)	$87.51
Benchmark					
WTI crude oil (per bbl)	$48.76	(48 %)	$92.91	(5 %)	$98.05
WCS crude oil (per bbl)[(a)]	35.28	(52 %)	73.60	1 %	72.77

[(a)] Average of monthly prices based upon average WTI adjusted for differentials unique to western Canada.

Consolidated Results of Operations: 2015 compared to 2014

Sales and other operating revenues, including related party are summarized by segment in the following table:

	Year Ended December 31,	
(In millions)	2015	2014
Sales and other operating revenues, including related party		
North America E&P	$3,358	$5,770
International E&P	728	1,410
Oil Sands Mining	815	1,556
Segment sales and other operating revenues, including related party	4,901	8,736
Unrealized gain on crude oil derivative instruments	50	—
Sales and other operating revenues, including related party	$4,951	$8,736

Below is a price/volume analysis for each segment. Refer to the preceding Operations and Market Conditions sections for additional detail related to our net sales volumes and average price realizations.

(In millions)	Year Ended December 31, 2014	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2015
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$5,240	$(3,006)	$671	$2,905
Natural gas	516	(243)	68	341
Realized gain on crude oil derivative instruments	—	78		78
Other sales	14			34
Total	$5,770			$3,358
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$1,240	$(509)	$(153)	$578
Natural gas	124	(8)	(8)	108
Other sales	46			42
Total	$1,410			$728
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$1,525	$(842)	$98	$781
Other sales	31			34
Total	$1,556			$815

Marketing revenues decreased $1,539 million in 2015 from 2014. Marketing activities include the purchase of commodities from third parties for resale and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Since the volume of marketing activity is based on market dynamics, it can fluctuate from period to period. The decreases are primarily related to the lower commodity price environment as well as lower marketed volumes in North America.

Income from equity method investments decreased $279 million primarily due to lower price realizations for LPG at our Alba Plant, LNG at our LNG facility and lower methanol prices at our AMPCO methanol facility, all of which are located in E.G. Also contributing to the decrease were lower sales volumes due to planned turnaround and maintenance activities at the AMPCO methanol plant, the Alba field and the LNG facility.

Net gain on disposal of assets in 2015 was related to the sale of our operated producing properties in the greater Ewing Bank area and non-operated producing interests in the Petronius field in the Gulf of Mexico. The gain associated with those assets was partially offset by the loss on sale of East Africa exploration acreage in Ethiopia and Kenya. The net loss on disposal of assets in 2014 was primarily related to the sale of non-core acreage located in the far northwest portion of the Williston Basin. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Production expenses decreased $552 million in 2015 from 2014. Our focus on cost discipline and efficiencies yielded sustainable savings in production costs. North America E&P declined $167 million due to lower operational, maintenance and labor costs. International E&P declined $131 million due to lower project work, repair, maintenance and turnaround costs, as well as lower production volumes. OSM declined $254 million primarily due to cost management, especially staffing and contract labor, lower fuel and utility costs, and lower feedstock purchases given the increased mine and upgrader reliability, combined with a more favorable exchange rate on expenses denominated in the Canadian dollar.

The production expense rate (expense rate per boe) decreased for each of our segments as total production costs declined due to reasons described in the preceding paragraph. The North America E&P and OSM segments also experienced volume increases, which further contributed to the expense rate decline. The following table provides production expense rates for each segment:

($ per boe)	2015	2014
North America E&P	$7.38	$10.25
International E&P	$5.99	$8.31
Oil Sands Mining [(a)]	$36.48	$44.53

(a) Production expense per synthetic crude oil barrel (before royalties) includes production costs, shipping and handling, taxes other than income and insurance costs and excludes pre-development costs.

Marketing expenses decreased $1,536 million in 2015 from the prior year, consistent with the decrease in marketing revenues discussed above.

Exploration expenses increased $525 million in 2015, primarily due to higher unproved property impairments in North America. During 2015, we made a strategic decision to reduce the overall level of our conventional exploration program; as a result, we impaired our Canadian in-situ assets, certain of our leases in the Gulf of Mexico and the Harir block in the Kurdistan Region of Iraq. We also impaired unproved property in Colorado in 2015, which we deemed uneconomic given our forecasted natural gas prices.

Unproved property impairments in 2014 primarily were a result of Eagle Ford and Bakken leases that either expired or we decided not to drill or extend.

Dry well costs for 2015 include the operated Solomon well in the Gulf of Mexico, our operated Sodalita West #1 exploratory well in E.G., and suspended well costs related to our Canadian in-situ assets at Birchwood. Dry well costs in 2014 also included our operated Sodalita West #1 exploratory well in E.G. which was drilling over year-end 2014, the operated Key Largo well, outside-operated Perseus well and the outside operated second Shenandoah appraisal well, all of which are located in the Gulf of Mexico. In addition, 2014 also includes our exploration programs in the Kurdistan Region of Iraq, Ethiopia and Kenya.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,	
(In millions)	2015	2014
Unproved property impairments	$964	$306
Dry well costs	250	317
Geological and geophysical	31	85
Other	73	85
Total exploration expenses	$1,318	$793

Exploration expense are also discussed in Item 8. Financial Statements and Supplementary Data - Note 13 to the consolidated financial statements.

Depreciation, depletion and amortization increased $96 million in 2015 from the prior year primarily as a result of higher North America E&P net sales volumes from our three U.S. resource plays. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs; therefore, proved reserve and production volumes have an impact on DD&A expense.

The DD&A rate (expense rate per boe), which is impacted by changes in proved reserves, capitalized costs and sales volume mix by field, can also cause changes to our DD&A. The following table provides DD&A rates for each segment. The DD&A rate for North America E&P decreased primarily as a result of a higher proved reserve base in the Eagle Ford. The International E&P rate increased primarily due to higher sales volumes from the Brae infill drilling program.

($ per boe)	2015	2014
North America E&P	$24.24	$26.95
International E&P	$6.95	$5.79
Oil Sands Mining	$12.48	$12.07

Impairments for 2015 included $340 million for the goodwill impairment of the North America E&P reporting unit, $335 million related to proved properties (primarily in Colorado and the Gulf of Mexico) as a result of lower forecasted commodity prices and $44 million associated with our disposition of natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma. Impairments for 2014 consisted primarily of proved properties in the Gulf of Mexico, Texas and North Dakota as a result of revisions to estimated abandonment costs and lower forecasted commodity prices. See Item 8. Financial Statements and Supplementary Data - Note 13 and Note 14 to the consolidated financial statement for additional detail.

Taxes other than income include production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to revenue and sales volumes. With the decrease in North America E&P revenues due to lower price realizations, taxes other than income decreased $172 million in 2015. This decrease was partially offset by an increase in sales volumes in North America E&P. The following table summarizes the components of taxes other than income:

	Year Ended December 31,	
(In millions)	2015	2014
Production and severance	$131	$240
Ad valorem	39	74
Other	64	92
Total	$234	$406

General and administrative expenses decreased $64 million primarily due to cost savings realized from the workforce reductions that occurred during 2015. This decrease was partially offset by severance expenses of $55 million associated with the workforce reductions and an increase in pension settlement expense. Pension settlement expenses in 2015 totaled $119 million as compared to $99 million in 2014.

Net interest and other increased $29 million primarily due to increased interest expense associated with an increase in long-term debt. The components of net interest and other are detailed in Item 8. Financial Statements and Supplementary Data - Note 8 to the consolidated financial statements.

Provision (benefit) for income taxes reflects an effective tax rate of (25%) and 29% for each of 2015 and 2014. See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for a discussion of the effective income tax rate.

Discontinued operations is presented net of tax. We closed the sale of our Angola assets and Norway business in 2014, and both are reflected as discontinued operations for 2014. Included in the discontinued operations for 2014 are after-tax gains of $532 million and $976 million related to the dispositions of Angola and Norway respectively. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements.

Segment Results: 2015 compared to 2014

Segment income (loss) for 2015 and 2014 is summarized and reconciled to net income (loss) in the following table.

	Year Ended December 31,	
(In millions)	2015	2014
North America E&P	$(486)	$693
International E&P	112	568
Oil Sands Mining	(113)	235
Segment income (loss)	(487)	1,496
Items not allocated to segments, net of income taxes	(1,717)	(527)
Income (loss) from continuing operations	(2,204)	969
Discontinued operations	—	2,077
Net income (loss)	$(2,204)	$3,046

North America E&P segment income (loss) decreased $1,179 million in 2015 compared to 2014. The decrease was primarily due to lower price realizations, which was partially offset by the impacts from the increased net sales volumes from the three U.S resource plays and lower production costs (even though net sales volumes increased).

International E&P segment income decreased $456 million in 2015 compared to 2014. The decrease was largely due to lower liquid hydrocarbon price realizations as well as reduced income from equity investments. These declines were partially offset by lower production, operating and exploration expenses.

Oil Sands Mining segment income (loss) decreased $348 million in 2015 compared to 2014 primarily as result of lower price realizations, partially offset by higher sales volumes and reduced production expenses.

Consolidated Results of Operations: 2014 compared to 2013

Sales and other operating revenues, including related party are summarized by segment in the following table:

	Year Ended December 31,	
(In millions)	2014	2013
Sales and other operating revenues, including related party		
North America E&P	$5,770	$5,068
International E&P	1,410	2,654
Oil Sands Mining	1,556	1,576
Segment sales and other operating revenues, including related party	8,736	9,298
Unrealized gain (loss) on crude oil derivative instruments	—	(52)
Sales and other operating revenues, including related party	$8,736	$9,246

Below is a price/volume analysis for each segment. Refer to the preceding Operations and Market Conditions sections for additional detail related to our net sales and average price realizations.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2013	Price Realizations	Net Sales Volumes	2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$4,638	$(557)	$1,159	$5,240
Natural gas	437	82	(3)	516
Realized gain on crude oil derivative instruments	(15)	15		—
Other sales	8			14
Total	$5,068			$5,770
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$2,398	$(397)	$(761)	$1,240
Natural gas	209	(74)	(11)	124
Other sales	47			46
Total	$2,654			$1,410
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$1,542	$(76)	$59	$1,525
Other sales	34			31
Total	$1,576			$1,556

Marketing revenues increased $31 million in 2014 from 2013. Marketing activities include the purchase of commodities from third parties for resale and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Since the volume of marketing activity is based on market dynamics, it can fluctuate from period to period. The increase in 2014 is primarily due to higher marketing activity levels in both the North America E&P and OSM segments.

Net loss on disposal of assets in 2014 primarily includes the pretax loss on the sale of non-core acreage located in the far northwest portion of the Williston Basin. The net loss on disposal of assets in 2013 primarily included pretax losses on the sale of our DJ Basin interests and the conveyance of our Marcellus interests to the operator, partially offset by pretax gains on the sales of the Neptune gas plant and our remaining assets in Alaska. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for further details about these dispositions.

Production expenses increased $90 million in 2014 from 2013 primarily related to increased North America E&P net sales volumes in the Eagle Ford and Bakken. The production expense rate (expense per boe) decreased in North America E&P in 2014 compared to 2013 primarily due to improved operating efficiencies in the Eagle Ford. The expense per boe increased in the International E&P segment due to a subsea power project at our non-operated Foinaven field as well as a turnaround in Brae in the U.K. and a non-recurring riser repair in E.G.

The following table provides production expense rates for each segment:

($ per boe)	2014	2013
North America E&P	$10.25	$10.86
International E&P	$8.31	$6.36
Oil Sands Mining [(a)]	$44.53	$46.30

(a) Production expense per synthetic crude oil barrel (before royalties) includes production costs, shipping and handling, taxes other than income and insurance costs and excludes pre-development costs.

Other operating expenses increased $73 million in 2014 from the prior year, primarily due to increased shipping and handling costs in North America in line with increased sales volumes, as well as the impact of a settlement related to the calculation of the net profits interest payments associated with our Alba Plant equity interests in E.G.

Marketing expenses increased $29 million in 2014 from the prior year, consistent with the decreases in marketing revenues discussed above.

Exploration expenses were $98 million lower in 2014 than in 2013, primarily related to our North America E&P segment as a result of larger non-cash unproved property impairments during 2013 related to Eagle Ford leases that either expired or that we did not expect to drill. These decreases were partially offset by increases in 2014 expenses related to the operated Key Largo, the outside-operated Perseus, the outside-operated second Shenandoah appraisal well in the Gulf of Mexico and our operated Sodalita West #1 exploratory well in E.G.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,	
(In millions)	2014	2013
Unproved property impairments	$306	$572
Dry well costs	317	148
Geological and geophysical	85	80
Other	85	91
Total exploration expenses	$793	$891

Exploration expense are also discussed in Item 8. Financial Statements and Supplementary Data - Note 13 to the consolidated financial statements.

Depreciation, depletion and amortization increased $361 million in 2014 from the prior year. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs; therefore, proved reserve and production volumes have an impact on DD&A expense. Increased DD&A expense in 2014 is primarily due to higher North America E&P sales volumes as a result of ongoing development programs over our three U.S. resource plays.

The DD&A rate, which is impacted by changes in reserves, capitalized costs and sales volume mix by field, can also cause changes to our DD&A. The following table provides DD&A rates for each segment:

($ per boe)	2014	2013
North America E&P	$26.95	$26.23
International E&P	$5.79	$5.86
Oil Sands Mining	$12.07	$12.39

Impairments for 2014 consisted primarily of proved properties in the Gulf of Mexico, Texas and North Dakota as a result of revisions to estimated abandonment costs and lower forecasted commodity prices. Impairments in 2013 primarily related to a second LNG production train in E.G., the Ozona development in the Gulf of Mexico and our Powder River asset in Wyoming. See Item 8. Financial Statements and Supplementary Data - Note 13 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to revenues and sales volumes. Taxes other than income increased $61 million in 2014 from 2013, consistent with similar increases in the North America E&P Segment.

	Year Ended December 31,	
(In millions)	2014	2013
Production and severance	$240	$202
Ad valorem	74	61
Other	92	82
Total	$406	$345

Net interest and other decreased $40 million in 2014 from 2013 primarily due to an increase in capitalized interest, higher net foreign currency gains and a dividend received in 2014 from a mutual insurance company of which we are an owner. See Item 8. Financial Statements and Supplementary Data - Note 8 to the consolidated financial statements for more detailed information.

Provision for income taxes reflects an effective tax rate of 29% and 61% for each of 2014 and 2013. See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for a discussion of the effective income tax rate.

Discontinued operations is presented net of tax. We closed the sale of our Angola assets and our Norway business in 2014, and both are reflected as discontinued operations and excluded from the International E&P segment in 2014 and 2013. Included in discontinued operations for 2014 are after-tax gains of $532 million and $976 million related to the dispositions of Angola and Norway, respectively. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Segment Results: 2014 compared to 2013

Segment income for 2014 and 2013 is summarized and reconciled to net income in the following table.

	Year Ended December 31,	
(In millions)	2014	2013
North America E&P	$693	$529
International E&P	568	758
Oil Sands Mining	235	206
Segment income	1,496	1,493
Items not allocated to segments, net of income taxes	(527)	(562)
Income from continuing operations	969	931
Discontinued operations	2,077	822
Net income	$3,046	$1,753

North America E&P segment income increased $164 million in 2014 compared to 2013. The increase was largely due to increased liquid hydrocarbon net sales volumes primarily in the Eagle Ford, Bakken and Oklahoma Resource Basins and lower exploration expenses, partially offset by lower average price realizations.

International E&P segment income decreased $190 million in 2014 compared to 2013. The decrease was primarily due to lower liquid hydrocarbon net sales volumes and lower average price realizations partially offset by a decrease in the taxes related to Libya, a high tax jurisdiction. Also, other operating expenses were higher in 2014 primarily due to the impact of a settlement related to the calculation of the net profits interest payments associated with our Alba Plant equity interests in E.G.

Oil Sands Mining segment income increased $29 million in 2014 compared to 2013. This increase was primarily a result of higher operating expenses in 2013 related to a turnaround.

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

Commodity prices are the most significant factor impacting our operating cash flows and the amount of capital available to reinvest into the business. The substantial decline in commodity prices that began in the second half of 2014 and continued into 2016 adversely affected our cash flows. In response to the lower commodity price environment, actions undertaken to protect our liquidity and capital structure include:

- Decreased our quarterly dividend from $0.21 to $0.05 per share, saving $425 million of cash on an annualized basis
- Scaled back our conventional exploration program to focus on our U.S. unconventional resources plays
- Reduced cash capital expenditures to $3.476 billion, a 33% decrease compared to 2014
- Announced a 2016 Capital Program of $1.4 billion
- Improved cost structure by reducing North America and International E&P production expenses 24% versus 2014
- Expect future G&A costs to be lower by $160 million on an annualized basis as a result of 2015 workforce reductions
- Issued $2 billion aggregate principal amount of unsecured senior notes, $1 billion of which was used to repay the 0.90% senior notes that matured in November 2015
- Increased the capacity of the revolving credit facility from $2.5 billion to $3.0 billion while also extending the maturity date an additional year to May 2020
- Repatriated Canadian earnings in a tax efficient manner, providing $250 million of cash available for use in U.S. operations
- Divested of certain non-core assets resulting in net proceeds of $225 million

At December 31, 2015, we had approximately $4.2 billion of liquidity consisting of $1.2 billion in cash and cash equivalents and $3.0 billion availability under our revolving credit facility. As previously discussed in Outlook, we are targeting a $1.4 billion Capital Program for 2016. Given our objective of spending within our cash flow in 2016, we are evaluating and we will continue to evaluate our options, which include our non-core asset disposition program, the flexibility to adjust our Capital Program or to seek to raise additional capital through the issuance of debt or equity securities. We will also continue to drive the fundamentals of expense management, including organizational capacity and operational reliability.

Cash Flows

The following table presents sources and uses of cash and cash equivalents for 2015, 2014 and 2013:

	Year Ended December 31,		
(In millions)	2015	2014	2013
Sources of cash and cash equivalents			
Continuing operations	$1,565	$4,736	$4,388
Discontinued operations	—	751	882
Disposals of assets	225	3,760	450
Maturities of short-term investment	925	—	—
Borrowings, net	1,996	—	—
Other	91	214	189
Total sources of cash and cash equivalents	$4,802	$9,461	$5,909
Uses of cash and cash equivalents			
Cash additions to property, plant and equipment	$(3,476)	$(5,160)	$(4,443)
Purchases of short-term investments	(925)	—	—
Investing activities of discontinued operations	—	(376)	(550)
Acquisitions	—	(21)	(74)
Purchases of common stock	—	(1,000)	(500)
Commercial paper, net	—	(135)	(65)
Debt repayments	(1,069)	(68)	(182)
Debt issuance costs	(19)	—	—
Dividends paid	(460)	(543)	(508)
Other	(30)	(24)	(7)
Total uses of cash and cash equivalents	$(5,979)	$(7,327)	$(6,329)

Cash flows from continuing operations in 2015 were lower than 2014 primarily as a result of commodity prices declines, which were partially offset by increased net sales volumes in the North America E&P segment. Cash flows from continuing operations in 2014 were higher than in 2013 due to increased net sales volumes in the North America E&P segment and lower cash tax payments (primarily Libya, a higher tax jurisdiction), partially offset by lower average price realizations in all segments, as well as lower net sales volumes in the International E&P segment.

Cash flows from discontinued operations primarily related to our Norway business, which we disposed of in the fourth quarter of 2014.

Disposals of assets in 2015 pertain to the sale of certain of our operated and non-operated producing properties in the Gulf of Mexico as well as natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma. Disposals in 2014 primarily reflect the proceeds from the sales of our Angola assets and our Norway business. In 2013, net proceeds were primarily related to the sales of our interests in Alaska, the Neptune gas plant and the DJ Basin. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Borrowings reflect net proceeds received from the issuance of senior notes in June 2015. See Liquidity and Capital Resources below for additional information. In November 2015, we repaid our $1 billion 0.90% senior notes upon maturity.

In October 2015, we announced an adjustment to our quarterly dividend. See Capital Requirements below for additional information.

Additions to property, plant and equipment are our most significant use of cash and cash equivalents. The following table shows capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows for 2015, 2014 and 2013:

	Year Ended December 31,		
(In millions)	2015	2014	2013
North America E&P	$2,553	$4,698	$3,649
International E&P	368	534	456
Oil Sands Mining [(a)]	(10)	212	286
Corporate	25	51	58
Total capital expenditures	2,936	5,495	4,449
Change in capital expenditure accrual	540	(335)	(6)
Additions to property, plant and equipment	$3,476	$5,160	$4,443

(a) Reflects reimbursements earned from the governments of Canada and Alberta related to funds previously expended for Quest CCS capital equipment. Quest CCS was successfully completed and commissioned in the fourth quarter of 2015.

During 2014, we acquired 29 million shares at a cost of $1 billion and in 2013 acquired 14 million shares at a cost of $500 million. There were no share repurchases in 2015.

See Item 8. Financial Statements and Supplementary Data – Note 23 to the consolidated financial statements for discussion of purchases of common stock.

Liquidity and Capital Resources

On June 10, 2015, we issued $2 billion aggregate principal amount of unsecured senior notes which consist of the following series:

- $600 million of 2.70% senior notes due June 1, 2020
- $900 million of 3.85% senior notes due June 1, 2025
- $500 million of 5.20% senior notes due June 1, 2045

Interest on each series of senior notes is payable semi-annually beginning December 1, 2015. We used the aggregate net proceeds to repay our $1 billion 0.90% senior notes on November 2, 2015, and the remainder for general corporate purposes.

In May 2015, we amended our $2.5 billion Credit Facility to increase the facility size by $500 million to a total of $3.0 billion and extend the maturity date by an additional year such that the Credit Facility now matures in May 2020. The amendment additionally provides us the ability to request two one-year extensions to the maturity date and an option to increase the commitment amount by up to an additional $500 million, subject to the consent of any increasing lenders. The sub-facilities for swing-line loans and letters of credit remain unchanged allowing up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender, as well as the borrowing options under the Credit Facility, remain unchanged.

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, capital market transactions, our committed revolving credit facility and sales of non-core assets. Our working capital requirements are supported by these sources and we may issue either commercial paper backed by our $3.0 billion revolving credit facility or draw on our $3.0 billion revolving credit facility to meet short-term cash requirements or issue debt or equity securities through the shelf registration statement discussed below as part of our longer-term liquidity and capital management. Because of the alternatives available to us as discussed above, 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 and other amounts that may ultimately be paid in connection with contingencies.

General economic conditions, commodity prices, and financial, business and other factors could affect our operations and our ability to access the capital markets. A downgrade in our credit ratings could negatively impact our cost of capital and our ability to access the capital markets, increase the interest rate and fees we pay on our unsecured revolving credit facility, restrict our access to the commercial paper market, or require us to post letters of credit or other forms of collateral for certain obligations. See Item 1A. Risk Factors for a further discussion of how a downgrade in our credit ratings, particularly below investment grade, could affect us.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness could increase the risk that our liquidity and financial flexibility deteriorates. See Item 1A. Risk Factors for a further discussion of how our level of indebtedness could affect us.

Capital Resources

Credit Arrangements and Borrowings

At December 31, 2015, we had no borrowings against our revolving credit facility and no amounts outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

At December 31, 2015, we had $7.3 billion in long-term debt outstanding. 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.

Shelf Registration

We have a universal shelf registration statement filed with the SEC, under which we, as "well-known seasoned issuer" for purposes 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.

Asset Disposals

We are targeting to generate $750 million to $1 billion from select non-core asset sales. During 2015, we closed or announced asset sales in excess of $300 million (before closing adjustments) from this program by divesting of certain operated and non-operated producing properties in the Gulf of Mexico and natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma. See Note 5 to the consolidated financial statements for additional discussion of these dispositions.

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% at December 31, 2015 and 16% at December 31, 2014.

(Dollars in millions)	2015		2014	
Long-term debt due within one year	$1		$1,068	
Long-term debt	7,276		5,295	
Total debt	$7,277		$6,363	
Cash and cash equivalents	$1,221		$2,398	
Equity	$18,553		$21,020	
Calculation				
Total debt	$7,277		$6,363	
Minus cash and cash equivalents	1,221		2,398	
Total debt minus cash and cash equivalents	6,056		3,965	
Total debt	$7,277		$6,363	
Plus equity	18,553		21,020	
Minus cash and cash equivalents	1,221		2,398	
Total debt plus equity minus cash, cash equivalents	$24,609		$24,985	
Cash-adjusted debt-to-capital ratio	25	%	16	%

Capital Requirements

Capital Spending

Our approved Capital Program for 2016 is $1.4 billion. Additional details were previously discussed in Outlook.

Share Repurchase Program

The remaining share repurchase authorization as of December 31, 2015 is $1.5 billion.

Other Expected Cash Outflows

On January 27, 2016, our Board of Directors approved a dividend of $0.05 per share for the fourth quarter of 2015. The dividend is payable on March 10, 2016 to shareholders on record on February 17, 2016. The fourth quarter dividend is consistent with the third quarter of 2015, which was a reduction as compared to the quarterly dividends of $0.21 per share for each of the first and second quarters. We reduced the dividend as as we continue to address the uncertainty of a lower for

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longer commodity price environment, align with our priority of maintaining a strong balance sheet through the cycle and provide additional capital flexibility to support growth from the U.S. resource plays when commodity prices improve.

We plan to make contributions of up to $62 million to our funded pension plans during 2016. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $8 million and $21 million in 2016.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2015.

(In millions)	Total	2016	2017-2018	2019-2020	Later Years
Short and long-term debt (includes interest)[(a)]	$11,870	$365	$2,196	$1,354	$7,955
Lease obligations	178	30	52	50	46
Purchase obligations:					
Oil and gas activities[(b)]	382	263	70	37	12
Service and materials contracts[(c)]	761	90	128	37	506
Transportation and related contracts	1,768	256	495	393	624
Drilling rigs and fracturing crews[(d)]	270	119	151	—	—
Other [(g)]	141	26	29	30	56
Total purchase obligations	3,322	754	873	497	1,198
Other long-term liabilities reported in the consolidated balance sheet[(e)]	618	94	158	113	253
Total contractual cash obligations[(f)]	$15,988	$1,243	$3,279	$2,014	$9,452

(a) Includes anticipated cash payments for interest of $365 million for 2016, $660 million for 2017-2018, $526 million for 2019-2020 and $3,018 million for the remaining years for a total of $4,569 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) Some contracts may be canceled at an amount less than the contract amount. Were we to elect that option where possible at December 31, 2015 our minimum commitment would be $163 million.

(e) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2025. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

(f) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,635 million. See Item 8. Financial Statements and Supplementary Data – Note 18 to the consolidated financial statements.

(g) We expect to make severance payments of approximately $8 million in 2016 related to the workforce reduction in 2015.

Transactions with Related Parties

We own a 63% working interest in the Alba field offshore E.G. Onshore E.G., we own a 52% interest in an LPG processing plant, a 60% interest in an LNG production facility and a 45% 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.

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, 2015, 2014 and 2013 aggregated $53 million, $101 million and $119 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 and future abandonment liabilities.

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.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We strive to comply with all legal requirements regarding the environment, but as 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 1A. Risk Factors and Item 3. Legal Proceedings.

Critical Accounting Estimates

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

Estimated Quantities of Net Reserves

The estimation of quantities of net reserves is a highly technical process performed by our engineers for crude oil and condensate, NGLs 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. Further reductions in commodity prices could have a material effect on the quantity and present value of our proved reserves and could also cause further reductions to our near term capital programs which would defer investment until prices improved. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves.

Our December 31, 2015 proved reserves were calculated using the SEC pricing. The table below provides the 2015 SEC pricing for certain of the benchmark prices as well as the unweighted average for the first two months of 2016:

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	Unweighted 12-month 2015 Average	Unweighted 2-month 2016 Average
WTI Crude oil	$50.28	$34.19
Henry Hub natural gas	$2.59	$2.28
Brent crude oil	$54.25	$34.86
Natural gas liquids	$17.32	$12.87

When determining the December 31, 2015 proved reserves for each property, the benchmark prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

Beginning in the second half of 2014, the crude oil and Henry Hub benchmarks began to decline and these declines continued through 2015 and into 2016. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves. For further discussion of risks associated with our estimation of proved reserves, see Part I. Item 1A Risk Factors.

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 crude oil and condensate, NGLs, 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. Accordingly, a decline in estimates of quantities of net proved reserves could cause us to perform an impairment analysis to determine if the carrying value exceeds the fair value and could result in an impairment charge. In addition, a decline in estimates of quantities of net proved reserves could prompt a goodwill impairment analysis of our International E&P segment before or after our annual test at April 1.

Depreciation and depletion of crude oil and condensate, NGLs, 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. While revisions of previous reserve estimates have not been significant to the depreciation and depletion rate to any of our segments over the past three years, any reduction in proved reserves, especially as a result of lower commodity prices, could result in an acceleration of future DD&A expense. The following table illustrates, on average, the sensitivity of each segment's units-of-production DD&A per boe and pretax income to a hypothetical 10% change in 2015 proved reserves based on 2015 production.

	Impact of a Ten% Increase in Proved Reserves		Impact of a Ten% Decrease in Proved Reserves	
(In millions, except per boe)	DD&A per boe	Pretax Income	DD&A per boe	Pretax Income
North America E&P	$(2.20)	$216	$2.69	$(264)
International E&P	$(0.63)	$27	$0.77	$(33)
Oil Sands Mining	$(1.04)	$17	$1.46	$(24)

Asset Retirement Obligations

We have material legal, regulatory and contractual obligations to remove and dismantle long-lived assets and to restore land or seabed at the end of oil and gas production operations, including bitumen mining operations. A liability equal to the fair value of such obligations and a corresponding capitalized asset retirement cost are recognized on the balance sheet in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be made. The capitalized asset retirement cost is depreciated using the units-of-production method and the discounted liability is accreted over the period until the obligation is satisfied, the impacts of which are recognized as DD&A in the consolidated statements of income. In many cases, the satisfaction and subsequent discharge of these liabilities is projected to occur many years, or even decades, into the future. Furthermore, the legal, regulatory and contractual requirements often do not provide specific guidance regarding removal practices and the criteria that must be fulfilled when the removal and/or restoration event actually occurs.

Estimates of retirement costs are developed for each property based on numerous factors, such as the scope of the dismantlement, timing of settlement, interpretation of legal, regulatory and contractual requirements, type of production and processing structures, depth of water (if applicable), reservoir characteristics, depth of the reservoir, market demand for equipment, currently available dismantlement and restoration procedures and consultations with construction and engineering professionals. Inflation rates and credit-adjusted-risk-free interest rates are then applied to estimate the fair values of the obligations. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Changes in estimated asset retirement obligations for late life assets could result in future impairment charges. See Item 8. Financial Statements and Supplementary Data – Note 18 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates.

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 obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

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, or range of present values, 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 do 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. 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; and
- recorded value of derivative instruments.

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of crude oil and condensate, NGLs, natural gas or synthetic crude oil, sustained declines in our common stock, reductions to our Capital Program, 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.

Impairment Assessments of Long-Lived Assets

Long-lived assets in use 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 an 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 our North America E&P and International E&P assets and at the project level for OSM assets. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value. During 2015, we determined that the substantial decline in commodity prices and the resulting change in future commodity price assumptions was a triggering event which required us to reassess long-lived assets related to oil and gas producing properties for impairment. We estimated the fair values using an income approach and recognized impairments during 2015. Commodity prices are one of the most significant inputs into our models. A further decline in our commodity price assumptions could result in additional future impairment charges. See Item 8. Financial Statements and Supplementary Data Note 13 and Note 15 to the consolidated financial statements for discussion of impairments recorded in 2015, 2014 and 2013 and the related fair value measurements.

Fair value calculated for the purpose of testing our long-lived assets for impairment is estimated using the present value of expected 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 crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil prices and estimates of such future prices are inherently imprecise.
- Estimated quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil. Such quantities are based on a combination of proved and risk-weighted probable reserves such that the combined volumes represent the most likely expectation of recovery.
- Expected timing of production. Production forecasts are the outcome of engineer studies which estimate reserves, as well as expected capital development programs. 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. A higher discount rate decreases the net present value of cash flows.
- Future capital requirements. Our estimates of future capital requirements are based upon a combination of 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. A further sustained decline in commodity prices may cause us to reassess our long-lived assets for impairment, and could result in future non-cash impairment charges as a result of such impairment assessments.

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g. reserves, pace and timing of development plans, commodity prices, capital expenditures, drilling and development costs 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.

Impairment Assessments of Goodwill

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. After we performed our annual impairment test in April 2015, there was a continued decline in commodity prices as discussed above. Downward revisions to forecasted commodity price assumptions and sustained price declines in our common stock were triggering events which required us to reassess our goodwill for impairment as of September 30 and December 31, 2015. Based on the results of these assessments, we fully impaired the goodwill associated with our N.A. E&P reporting unit. While the fair value of our International E&P reporting unit exceeded book value at December 31, 2015, subsequent commodity price and/or common stock price declines may cause us to reassess our goodwill for impairment and could result in a non-cash impairment charge in the future.

We estimated the fair values of the North America E&P and International E&P reporting units using a combination of market and income approaches. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. The market approach referenced observable inputs specific to us and our industry. The income approach calculated the present value of expected future cash flows, which were based on forecasted assumptions. Key assumptions to the income approach are the same as those described above regarding our impairment assessment of long-lived assets. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in such assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. See Item 8. Financial Statements and Supplementary Data Note 14 to the consolidated financial statements for additional discussion of the goodwill impairment recorded in 2015.

Derivatives

We record all derivative instruments at fair value. Fair value measurements 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 if 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. In the second quarter of 2015, we reviewed our operations and concluded that we do not have the same level of capital needs outside the U.S. as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings of approximately $1 billion associated with our Canadian operations to be permanently reinvested outside the U.S. As such, none our foreign earnings remain permanently reinvested abroad.

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 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 a combination of reserve categories related to our existing producing properties, as well as estimated quantities of crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, 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. A sustained decline in commodity prices could cause us to record a valuation allowance against our deferred tax assets and U.S. federal benefit of foreign tax credits.

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 U.S. pension plans and our other U.S. postretirement benefit 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 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% highest yielding issuances within each defined maturity group.

Of the assumptions used to measure obligations and estimated annual net periodic benefit cost as of December 31, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. The hypothetical impacts of a 0.25% change in the discount rates of 4.04% for our U.S. pension plans and 4.36% for our other U.S. postretirement benefit plans is summarized in the table below:

	Impact of a 0.25% Increase in Discount Rate		Impact of a 0.25% Decrease in Discount Rate	
(In millions)	Obligation	Expense	Obligation	Expense
U.S. pension plans	$(14)	$(1)	$14	$1
Other U.S. postretirement benefit plans	$(6)	$—	$7	$—

The asset rate of return assumption for the funded U.S. plan considers the plan's asset mix (currently targeted at approximately 55% equity and 45% other fixed income securities), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Decreasing the 6.75% 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 consolidated 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 other operating expense or general and administrative expense in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as taxes other than income. 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

See Item 8. Financial Statements and Supplementary Data – Note 2 to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of crude oil and condensate, NGLs, natural gas and synthetic crude oil prices as the volatility of these prices continues to impact our industry. We expect commodity prices to remain volatile and unpredictable in the future. 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. 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 – Notes 15 and 16 to the consolidated financial statements for more information about the fair value measurement of our derivatives, the amounts recorded in our consolidated balance sheets and statements of income and the related notional amounts.

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 periodically protect prices on forecasted sales to support cash flow and liquidity, as deemed appropriate. We may 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 business. Our consolidated results for 2015 and 2013 were impacted by crude oil derivatives related to a portion of our North America E&P crude oil sales. There were no crude oil derivatives in 2014. The table below provides a summary of open positions as of December 31, 2015:

Financial Instrument	Weighted Average Price	Barrels per day	Remaining Term
Three-Way Collars			
Ceiling	$60.03	10,000	January - March 2016 [(a)]
Floor	$50.20		
Sold put	$41.60		
Ceiling	$71.84	12,000	January- December 2016
Floor	$60.48		
Sold put	$50.00		
Ceiling	$73.13	2,000	January- June 2016 [(b)]
Floor	$65.00		
Sold put	$50.00		
Sold Call Options	$72.39	10,000	January- December 2016 [(c)]

(a) Counterparties have the option, exercisable on March 31, 2016, to extend these collars through September of 2016 at the same volume and weighted average price as the underlying three-way collars.

(b) Counterparty has the option, exercisable on June 30, 2016, to extend these collars through the remainder of 2016 at the same volume and weighted average price as the underlying three-way collars.

(c) Call options settle monthly.

The table below provides a sensitivity analysis of the projected incremental effect on income (loss) from operations of a hypothetical 10% change in NYMEX WTI prices on our open commodity derivatives as of December 31, 2015:

(In millions)	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Crude oil commodity derivatives	(8)	5

Interest Rate Risk

At December 31, 2015, our portfolio of long-term debt was substantially comprised of fixed rate instruments. We currently manage our exposure to interest rate movements by utilizing interest rate swap agreements that effectively convert a portion of our fixed rate debt to floating interest rate debt. As of December 31, 2015, we had multiple interest rate swap agreements with a total notional of $900 million designated as fair value hedges.

Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed rate debt portfolio affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than carrying value. Sensitivity analysis of the incremental effect of a hypothetical 10% change in interest rates on financial assets and liabilities as of December 31, 2015, is provided in the following table.

(In millions)	Fair Value		Incremental Change in Fair Value
Financial assets (liabilities): [a]			
Interest rate swap agreements	$8	[b]	$2
Long-term debt, including amounts due within one year	$(6,723)	[b][c]	$(307)

[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.

[c] Excludes capital leases.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. If commodity prices remain at or fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. We review the creditworthiness of counterparties and use master netting agreements when appropriate.

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/ Lee M. Tillman	/s/ John R. Sult
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

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). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. 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.

An evaluation of the design and effectiveness of our internal control over financial reporting, based on the 2013 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, 2015.

The effectiveness of Marathon Oil’s internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Lee M. Tillman	/s/ John R. Sult
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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework - 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The 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

Houston, Texas

February 25, 2016

MARATHON OIL CORPORATION
Consolidated Statements of Income

	Year Ended December 31,		
(In millions, except per share data)	2015	2014	2013
Revenues and other income:			
Sales and other operating revenues, including related party	$4,951	$8,736	$9,246
Marketing revenues	571	2,110	2,079
Income from equity method investments	145	424	423
Net gain (loss) on disposal of assets	120	(90)	(29)
Other income	74	78	64
Total revenues and other income	5,861	11,258	11,783
Costs and expenses:			
Production	1,694	2,246	2,156
Marketing, including purchases from related parties	569	2,105	2,076
Other operating	438	462	389
Exploration	1,318	793	891
Depreciation, depletion and amortization	2,957	2,861	2,500
Impairments	752	132	96
Taxes other than income	234	406	345
General and administrative	590	654	659
Total costs and expenses	8,552	9,659	9,112
Income (loss) from operations	(2,691)	1,599	2,671
Net interest and other	(267)	(238)	(278)
Income (loss) from continuing operations before income taxes	(2,958)	1,361	2,393
Provision (benefit) for income taxes	(754)	392	1,462
Income (loss) from continuing operations	(2,204)	969	931
Discontinued operations	—	2,077	822
Net income (loss)	$(2,204)	$3,046	$1,753
Per Share Data			
Basic:			
Income (loss) from continuing operations	$(3.26)	$1.42	$1.32
Discontinued operations	$—	$3.06	$1.17
Net income (loss)	$(3.26)	$4.48	$2.49
Diluted:			
Income (loss) from continuing operations	$(3.26)	$1.42	$1.31
Discontinued operations	$—	$3.04	$1.16
Net income (loss)	$(3.26)	$4.46	$2.47
Dividends	$0.68	$0.80	$0.72
Weighted average shares:			
Basic	677	680	705
Diluted	677	683	709

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
(In millions)	2015	2014	2013
Net income (loss)	$(2,204)	$3,046	$1,753
Other comprehensive income (loss)			
Postretirement and postemployment plans			
Change in actuarial loss and other	228	(52)	300
Income tax benefit (provision)	(86)	25	(112)
Postretirement and postemployment plans, net of tax	142	(27)	188
Derivative hedges			
Net unrecognized gain	—	1	1
Income tax provision	—	—	—
Derivative hedges, net of tax	—	1	1
Foreign currency translation and other			
Unrealized loss	—	—	(3)
Income tax benefit (provision)	—	(1)	1
Foreign currency translation and other, net of tax	—	(1)	(2)
Other comprehensive income (loss)	142	(27)	187
Comprehensive income (loss)	$(2,062)	$3,019	$1,940

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets

	December 31,	
(In millions, except par values and share amounts)	2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$1,221	$2,398
Receivables, less reserve of $4 and $3	912	1,729
Inventories	313	357
Other current assets	144	109
Total current assets	2,590	4,593
Equity method investments	1,003	1,113
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $23,260 and $21,884	27,061	29,040
Goodwill	115	459
Other noncurrent assets	1,542	778
Total assets	$32,311	$35,983
Liabilities		
Current liabilities:		
Accounts payable	1,313	2,545
Payroll and benefits payable	133	191
Accrued taxes	132	285
Other current liabilities	150	290
Long-term debt due within one year	1	1,068
Total current liabilities	1,729	4,379
Long-term debt	7,276	5,295
Deferred tax liabilities	2,441	2,486
Defined benefit postretirement plan obligations	403	598
Asset retirement obligations	1,601	1,917
Deferred credits and other liabilities	308	288
Total liabilities	13,758	14,963
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 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 – 93 million and 95 million shares	(3,554)	(3,642)
Additional paid-in capital	6,498	6,531
Retained earnings	14,974	17,638
Accumulated other comprehensive loss	(135)	(277)
Total stockholders' equity	18,553	21,020
Total liabilities and stockholders' equity	$32,311	$35,983

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

	Year Ended December 31,		
(In millions)	2015	2014	2013
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income (loss)	$(2,204)	$3,046	$1,753
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations	—	(2,077)	(822)
Deferred income taxes	(806)	88	(34)
Depreciation, depletion and amortization	2,957	2,861	2,500
Impairments	752	132	96
Pension and other postretirement benefits, net	1	(34)	45
Exploratory dry well costs and unproved property impairments	1,214	623	720
Net (gain) loss on disposal of assets	(120)	90	29
Equity method investments, net	33	27	12
Changes in:			
Current receivables	817	119	217
Inventories	36	(11)	(19)
Current accounts payable and accrued liabilities	(965)	(33)	(208)
All other operating, net	(150)	(95)	99
Net cash provided by continuing operations	1,565	4,736	4,388
Net cash provided by discontinued operations	—	751	882
Net cash provided by operating activities	1,565	5,487	5,270
Investing activities:			
Acquisitions, net of cash acquired	—	(21)	(74)
Additions to property, plant and equipment	(3,476)	(5,160)	(4,443)
Disposal of assets	225	3,760	450
Investments - return of capital	77	61	61
Investing activities of discontinued operations	—	(376)	(550)
Purchases of short term investments	(925)	—	—
Maturities of short term investments	925	—	—
All other investing, net	(28)	(10)	35
Net cash used in investing activities	(3,202)	(1,746)	(4,521)
Financing activities:			
Commercial paper, net	—	(135)	(65)
Borrowings	1,996	—	—
Debt issuance costs	(19)	—	—
Debt repayments	(1,069)	(68)	(182)
Purchases of common stock	—	(1,000)	(500)
Dividends paid	(460)	(543)	(508)
All other financing, net	14	153	93
Net cash provided by (used in) financing activities	462	(1,593)	(1,162)
Effect of exchange rate changes on cash:			
Continuing operations	(2)	(2)	(3)
Discontinued operations	—	(12)	(4)
Net increase (decrease) in cash and cash equivalents	(1,177)	2,134	(420)
Cash and cash equivalents at beginning of period	2,398	264	684
Cash and cash equivalents at end of period	$1,221	$2,398	$264

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

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

	Total Equity of Marathon Oil Stockholders							
(In millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Equity
December 31, 2012 Balance	$—	$ 770	$ —	$(2,560)	$ 6,616	$13,890	$ (433)	$18,283
Shares issued - stock-based compensation	—	—	—	170	(44)	—	—	126
Shares repurchased	—	—	—	(513)	—	—	—	(513)
Stock-based compensation	—	—	—	—	20	—	—	20
Net income	—	—	—	—	—	1,753	—	1,753
Other comprehensive income	—	—	—	—	—	—	183	183
Dividends paid	—	—	—	—	—	(508)	—	(508)
December 31, 2013 Balance	$—	$ 770	$ —	$(2,903)	$ 6,592	$15,135	$ (250)	$19,344
Shares issued - stock-based compensation	—	—	—	276	(57)	—	—	219
Shares repurchased	—	—	—	(1,015)	—	—	—	(1,015)
Stock-based compensation	—	—	—	—	(4)	—	—	(4)
Net income	—	—	—	—	—	3,046	—	3,046
Other comprehensive loss	—	—	—	—	—	—	(27)	(27)
Dividends paid	—	—	—	—	—	(543)	—	(543)
December 31, 2014 Balance	$—	$ 770	$ —	$(3,642)	$ 6,531	$17,638	$ (277)	$21,020
Shares issued - stock-based compensation	—	—	—	96	(32)	—	—	64
Shares repurchased	—	—	—	(8)	—	—	—	(8)
Stock-based compensation	—	—	—	—	(1)	—	—	(1)
Net loss	—	—	—	—	—	(2,204)	—	(2,204)
Other comprehensive income	—	—	—	—	—	—	142	142
Dividends paid	—	—	—	—	—	(460)	—	(460)
December 31, 2015 Balance	$—	$ 770	$ —	$(3,554)	$ 6,498	$14,974	$ (135)	$18,553

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock
December 31, 2012 Balance	—	770	—	63
Shares issued - stock-based compensation	—	—	—	(4)
Shares repurchased	—	—	—	14
December 31, 2013 Balance	—	770	—	73
Shares issued - stock-based compensation	—	—	—	(7)
Shares repurchased	—	—	—	29
December 31, 2014 Balance	—	770	—	95
Shares issued - stock-based compensation	—	—	—	(2)

Shares repurchased	—	—	—	—
December 31, 2015 Balance	—	770	—	93

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 a global energy company engaged in exploration, production and marketing of crude oil and condensate, NGLs and natural gas; as well as production and marketing of products manufactured from natural gas, such as LNG and methanol, in E.G.; and oil sands mining, bitumen transportation and upgrading, and marketing of synthetic crude oil and vacuum gas oil in Canada.
Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.
Equity method investments – 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 included as noncurrent assets on the consolidated balance sheet. These 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.
Discontinued operations – Disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated. As a result of the sale of our Angola assets and our Norway business in 2014 (see Note 5), these businesses are reflected as discontinued operations in the periods prior to and including 2014.
Use of estimates – The preparation of financial statements in accordance with U.S. GAAP 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.
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. 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.
In the lower 48 states of the U.S., production volumes of crude oil and condensate, NGLs and natural gas are generally sold immediately and transported to market. In international locations, liquid hydrocarbon 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.
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.
Short-term Investments - Our short-term investments are comprised of bank time deposits with original maturities of greater than three months but less than twelve months. They are classified as held-to-maturity investments, which are recorded at amortized cost.
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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Inventories – Crude oil and natural gas inventories are recorded at weighted average cost and carried at the lower of cost or market value. Materials and supplies inventory consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.
During the fourth quarter of 2015, we elected to change our accounting method related to our U.S. crude oil and natural gas inventories from last in, first out ("LIFO") method to weighted average cost. At December 31, 2015, this inventory represented $5 million of our total inventory value, see Note 10 to the consolidated financial statements for additional detail related to inventories. We believe this change is preferable as it provides consistent application of the cost basis for all categories of inventories across our worldwide portfolio, more accurately reflects the current value of inventory which provides for a better matching of expenses to revenues, and enhances comparability to our peers.
The effect of changing the method from LIFO to weighted average cost was immaterial for all current and prior periods. We recorded the cumulative effect of this change within our Consolidated Balance Sheets and Consolidated Statements of Income during the fourth quarter of 2015 and did not adjust previously reported periods. This resulted in an increase in our Inventories account of $2 million and a decrease in Production costs by $2 million. The change in method had an immaterial impact to income from continuing operations, with no change to basic or diluted earnings per share.
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 and interest rate swaps are reflected on our consolidated balance sheet on a net basis by counterparty, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, foreign currency risk and interest rate risk are classified in operating activities. Our derivative instruments contain no significant contingent credit features.
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 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.
Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. If significant transfers occur, they would be disclosed in Note 15 to the consolidated financial statements.
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 oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells in progress and those 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 exploratory well costs is monitored continuously and reviewed at least quarterly.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties, which include 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, as well as property, plant and equipment unrelated to oil and gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets as summarized below.

Type of Asset	Range of Useful Lives
Office furniture, equipment and computer hardware	3 to 15 years
Pipelines	10 to 40 years
Plants, facilities, mine equipment and infrastructure	1 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. 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. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is 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 is 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 a reporting unit. The fair value of a 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 impairments.
Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred and can include the costs of contractor repair services, materials and supplies, equipment rentals and our labor costs.
Environmental costs – 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 or reliably determinable. Environmental expenditures are capitalized only if the costs mitigate or prevent future contamination or if the costs improve the environmental safety or efficiency of the existing assets.
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.

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 based on estimated proved reserves 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 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 volatility of our stock price and the stock price in relation to the strike 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. The fair value of our stock-based performance units is estimated using the Monte Carlo simulation method. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement.

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.

2. Accounting Standards

Not Yet Adopted

In July 2015, the FASB issued an update that requires an entity to measure inventory at the lower of cost and net realizable value. This excludes inventory measured using LIFO or the retail inventory method. This standard is effective for us in the first quarter of 2017 and will be applied prospectively. Early adoption is permitted. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2015, the FASB issued an update that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The amendment also removes certain disclosure requirements regarding all investments that are eligible to be measured using the net asset value per share practical expedient and only requires certain disclosures on those investments for which an entity elects to use the net asset value per share expedient. This standard is effective for us in the first quarter of 2016 and will be applied on a retrospective basis. Early adoption is permitted. This standard only modifies disclosure requirements; as such, there will be no impact on our consolidated results of operations, financial position or cash flows.

In February 2015, the FASB issued an amendment to the guidance for determining whether an entity is a variable interest entity ("VIE"). The standard does not add or remove any of the five characteristics that determine if an entity is a VIE. However, it does change the manner in which a reporting entity assesses one of the characteristics. In particular, when decision-making over the entity's most significant activities has been outsourced, the standard changes how a reporting entity assesses if the equity holders at risk lack decision making rights. This standard is effective for us for annual periods beginning after December 15, 2015 and early adoption is permitted, including in interim periods. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In August 2014, the FASB issued an update that requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards. This standard is effective for us in the first quarter of 2017 and early adoption is permitted. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2014 and August 2015, the FASB issued an update that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. Among other things, the standard requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in the first quarter of 2018 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is permitted. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In November 2015, the FASB issued an update that requires an entity to classify deferred income tax liabilities and assets as noncurrent in a classified statement of financial position. The amendments are effective for us in the first quarter of 2017 and early adoption is permitted. We elected to early adopt these amendments in the fourth quarter of 2015 on a prospective basis. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In April 2015, the FASB issued an update that requires debt issuance costs to be presented in the balance sheet as a direct reduction from the associated debt liability. This standard is effective for us in the first quarter of 2016 and early adoption is permitted. We elected to early adopt these amendments in the fourth quarter of 2015 on a retrospective basis. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In April 2014, the FASB issued an amendment to accounting standards that changes the criteria for reporting discontinued operations while enhancing related disclosures. Under the amendment, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization’s operations and financial results. Expanded disclosures about the assets, liabilities, income and expenses of discontinued operations are required. In addition, disclosure of the pretax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting will be made in order to provide users with information about the ongoing trends in an organization’s results from continuing operations. The amendments were effective for us in the first quarter of 2015. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

3. Variable Interest Entities

The owners of the AOSP, in which we hold a 20% 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 $2 million current liability recorded at December 31, 2015 and $3 million at December 31, 2014. 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 VIE. We hold a variable interest but are not the primary beneficiary because our shipments are only 20% of the total; therefore the Corridor Pipeline is not consolidated by us. 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 $447 million as of December 31, 2015. 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.

4. Acquisitions

2014 - North America E&P

In the fourth quarter of 2014, we acquired additional acres in the SCOOP, at a cost of $58 million after final settlement adjustments.

In the third quarter of 2014, we acquired acreage in the Oklahoma Resource Basins at a cost of $68 million after final settlement adjustments.

2013 - North America E&P

In July 2013, we acquired additional acreage in the Eagle Ford in a transaction valued at $97 million, including a carried interest of $23 million which was fully satisfied in 2014. The transaction was accounted for as a business combination, with the entire up-front cash consideration of $74 million allocated to property, plant and equipment at the acquisition date.

The fair values of assets acquired and liabilities assumed in the business combination 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 and a discount rate of approximately 10%. 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.

5. Dispositions

2015 - North America E&P Segment

In November 2015, we entered into an agreement to sell our operated producing properties in the greater Ewing Bank area and non-operated producing interests in the Petronius and Neptune fields in the Gulf of Mexico. The transaction closed in December 2015, excluding the Neptune field, for proceeds of $111 million. A $228 million pretax gain was recorded in the fourth quarter of 2015. Assets held for sale in the December 31, 2015 consolidated balance sheet were related to the Neptune field that was pending at that date and included $31 million in total assets and $54 million of total liabilities. The Neptune field transaction closed during the first quarter of 2016 for cash proceeds of $4 million.

In August 2015, we closed the sale of our East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets for proceeds of $100 million and recorded a pretax loss of $1 million. During the second quarter of 2015, we recorded a non-cash impairment charge of $44 million related to these assets (see Note 15).

2015 - International E&P Segment

In September 2015, we entered into agreements to sell our East Africa exploration acreage in Ethiopia and Kenya. A pretax loss of $109 million was recorded in the third quarter of 2015. The Kenya transaction closed in February 2016 and the Ethiopia transaction is expected to close in the first quarter of 2016. Cash proceeds for both transactions are expected to be $10 million, before closing adjustments.

2014 - North America E&P Segment

In June 2014, we closed the sale of non-core acreage located in the far northwest portion of the Williston Basin for proceeds of $90 million. A pretax loss of $91 million was recorded in the second quarter of 2014.

2014 - International E&P Segment

In June 2014, we entered into an agreement to sell our Norway business, including the operated Alvheim FPSO, 10 operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea. The transaction closed in the fourth quarter of 2014 for proceeds of $2.1 billion, before netting $589 million cash transferred to the buyer. A $976 million after-tax gain on the sale of Norway business was recorded in the fourth quarter of 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

Our Norway business is reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for the periods prior to and including 2014. Select amounts reported in discontinued operations were as follows:

	Year Ended December 31,	
(In millions)	2014	2013
Revenues applicable to discontinued operations	$1,981	$3,176

Pretax income from discontinued operations	$1,693	$2,537
Pretax gain on disposition of discontinued operations	$1,406	$—

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In the first quarter of 2014, we closed the sales of our 10% non-operated working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. A $532 million after-tax gain on the sale of our Angola assets was recorded in 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

Our Angola operations are reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for the periods prior to and including 2014. Select amounts reported in discontinued operations were as follows:

	Year Ended December 31,	
(In millions)	2014	2013
Revenues applicable to discontinued operations	$58	$361
Pretax income from discontinued operations	$51	$247
Pretax gain on disposition of discontinued operations	$426	$—

2013 - North America E&P Segment

In June 2013, we closed the sale of our interests in the DJ Basin for proceeds of $19 million. A pretax loss of $114 million was recorded in the second quarter of 2013.

In February 2013, we conveyed our interests in the Marcellus natural gas shale play to the operator. A $43 million pretax loss was recorded in the first quarter of 2013.

In February 2013, we closed the sale of our interest in the Neptune gas plant, located onshore Louisiana, for proceeds of $166 million. A $98 million pretax gain was recorded in the first quarter of 2013.

In January 2013, we closed the sale of our assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments were made in the second quarter of 2013, the pretax gain on this sale was $55 million.

2013 - International E&P Segment

In the fourth quarter of 2013, we transferred our 45% working interest and operatorship in the Safen block in the Kurdistan Region of Iraq at a pretax loss of $17 million.

6. Income (Loss) per Common Share

Basic income (loss) per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options in all years and stock appreciation rights in 2013, provided the effect is not antidilutive. The per share calculations below exclude 13 million, 4 million and 5 million stock options in 2015, 2014 and 2013 that were antidilutive.

	Year Ended December 31,		
(In millions, except per share data)	2015	2014	2013
Income (loss) from continuing operations	$(2,204)	$969	$931
Discontinued operations	—	2,077	822
Net income (loss)	$(2,204)	$3,046	$1,753
Weighted average common shares outstanding	677	680	705
Effect of dilutive securities	—	3	4
Weighted average common shares, diluted	677	683	709
Per basic share:			
Income (loss) from continuing operations	$(3.26)	$1.42	$1.32
Discontinued operations	$—	$3.06	$1.17
Net income (loss)	$(3.26)	$4.48	$2.49
Per diluted share:			
Income (loss) from continuing operations	$(3.26)	$1.42	$1.31

Discontinued operations	$—	$3.04	$1.16
Net income (loss)	$(3.26)	$4.46	$2.47

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7. Segment Information

We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers:

- North America E&P ("N.A. E&P") – explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P ("Int'l E&P") – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining ("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.

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 excluding certain items not allocated to segments, net of income taxes, attributable to the operating segments. A portion of our corporate and operations support general and administrative costs are not allocated to the operating segments. These unallocated costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Gains or losses on dispositions, certain impairments, change in tax expense associated with a tax rate change, 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 5, we closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are reflected as discontinued operations and excluded from the International E&P segment for 2014 and 2013.

Year Ended December 31, 2015				Not Allocated		
(In millions)	N.A. E&P	Int'l E&P	OSM	to Segments		Total
Sales and other operating revenues	$3,358	$728	$815	$50	[c]	$4,951
Marketing revenues	396	103	72	—		571
Total revenues	3,754	831	887	50		5,522
Income (loss) from equity method investments	—	157	—	(12)	[d]	145
Net gain on disposal of assets and other income	24	27	21	122	[e]	194
Less:						
Production expenses	724	255	715	—		1,694
Marketing costs	401	99	69	—		569
Exploration expenses	362	101	—	855	[f]	1,318
Depreciation, depletion and amortization	2,377	295	236	49		2,957
Impairments	2	—	5	745	[g]	752
Other expenses [a]	462	92	34	440	[h]	1,028
Taxes other than income	215	—	18	1		234
Net interest and other	—	—	—	267		267
Income tax provision (benefit)	(279)	61	(56)	(480)	[i]	(754)
Segment income (loss)/Income (loss) from continuing operations	$(486)	$112	$(113)	$(1,717)		$(2,204)
Capital expenditures [b]	$2,553	$368	$(10)	$25		$2,936

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized gain on crude oil derivative instruments.
[d] Partial impairment of investment in equity method investee (See Note 15).
[e] Primarily related to gain on sale of our properties and interests in the Gulf of Mexico, partially offset by the loss on sale of East Africa exploration acreage (see Note 5).

(f) Unproved property impairments associated with lower forecasted commodity prices and change in conventional exploration strategy (See Note 13).

(g) Goodwill impairment (see Note 14) and proved property impairments (see Note 15).

(h) Includes pension settlement loss of $119 million (see Note 20) and severance related expenses associated with workforce reductions of $55 million.

(i) Includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase (see Note 9).

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Year Ended December 31, 2014 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
Sales and other operating revenues	$5,770	$1,410	$1,556	$—		$8,736
Marketing revenues	1,839	219	52	—		2,110
Total revenues	7,609	1,629	1,608	—		10,846
Income from equity method investments	—	424	—	—		424
Net gain (loss) on disposal of assets and other income	23	57	4	(96	) [c]	(12)
Less:						
Production expenses	891	386	969	—		2,246
Marketing costs	1,836	217	52	—		2,105
Exploration expenses	608	185	—	—		793
Depreciation, depletion and amortization	2,342	269	206	44		2,861
Impairments	23	—	—	109	[d]	132
Other expenses [a]	473	197	54	392	[e]	1,116
Taxes other than income	385	—	20	1		406
Net interest and other	—	—	—	238		238
Income tax provision (benefit)	381	288	76	(353	)	392
Segment income/Income from continuing operations	$693	$568	$235	$(527	)	$969
Capital expenditures [b]	$4,698	$534	$212	$51		$5,495

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Primarily related to the sale of non-core acreage in our North America E&P segment (See Note 5).
[d] Proved Property impairments (See Note 15)
[e] Includes pension settlement loss of $99 million (See Note 20).

Year Ended December 31, 2013 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
Sales and other operating revenues	$5,068	$2,654	$1,576	$(52	) [c]	$9,246
Marketing revenues	1,797	264	18	—		2,079
Total revenues	6,865	2,918	1,594	(52	)	11,325
Income from equity method investments	—	427	—	(4	) [d]	423
Net gain (loss) on disposal of assets and other income	12	50	5	(32	) [e]	35
Less:						
Production expenses	797	359	1,000	—		2,156
Marketing costs	1,796	262	18	—		2,076
Exploration expenses	725	166	—	—		891
Depreciation, depletion and amortization	1,927	331	218	24		2,500
Impairments	41	—	—	55	[f]	96
Other expenses [a]	420	161	66	401	[g]	1,048
Taxes other than income	318	—	22	5		345
Net interest and other	—	—	—	278		278
Income tax provision (benefit)	324	1,358	69	(289	)	1,462
Segment income/Income from continuing operations	$529	$758	$206	$(562	)	$931
Capital expenditures [b]	$3,649	$456	$286	$58		$4,449

[a] Includes other operating expenses and general and administrative expenses.

(b) Includes accruals.

(c) Unrealized loss on crude oil derivative instruments (see Note 16).

(d) EGHoldings impairment (See Note 15).

(e) Related to the disposal of assets from our North America E&P Segment (see Note 5).

(f) Proved property impairments (see Note 15).

(g) Includes pension settlement loss of $45 million (see Note 20).

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

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	Year Ended December 31,		
(In millions)	2015	2014	2013
United States	$3,804	$7,609	$6,813
Canada	887	1,608	1,594
Libya[a]	—	244	1,106
Other international	831	1,385	1,812
Total revenues	$5,522	$10,846	$11,325

[a] See Note 12 for discussion of Libya operations.

In 2015, sales to Irving Oil and Shell Oil and each of their respective affiliates accounted for approximately 13% and 11% of our total revenues. In 2014, sales to Shell Oil and its affiliates accounted for approximately 10% of our total revenues. In 2013, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 10% of our total revenues

Revenues by product line were:

	Year Ended December 31,		
(In millions)	2015	2014	2013
Crude oil and condensate	$3,963	$8,170	$8,688
Natural gas liquids	203	371	313
Natural gas	464	693	693
Synthetic crude oil	781	1,525	1,542
Other	111	87	89
Total revenues	$5,522	$10,846	$11,325

The following summarizes property, plant and equipment and equity method investments.

	December 31,	
(In millions)	2015	2014
United States	$15,353	$16,518
Canada	9,197	9,802
Equatorial Guinea	1,917	1,949
Other international	1,597	1,884
Total long-lived assets	$28,064	$30,153

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8. Other Items

Net interest and other

	Year Ended December 31,		
(In millions)	2015	2014	2013
Interest:			
Interest income	$9	$7	$5
Interest expense	(358)	(309)	(319)
Income on interest rate swaps	11	12	9
Interest capitalized	26	20	12
Total interest	(312)	(270)	(293)
Other:			
Net foreign currency gains	23	21	14
Other	22	11	1
Total other	45	32	15
Net interest and other	$(267)	$(238)	$(278)

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

	Year Ended December 31,		
(In millions)	2015	2014	2013
Net interest and other	$23	$21	$14
Provision for income taxes	(11)	(12)	(2)
Aggregate foreign currency gains	$12	$9	$12

9. Income Taxes

Income tax provisions (benefits) for continuing operations were:

	Year Ended December 31,								
	2015			2014			2013		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$(43)	$(687)	$(730)	$15	$62	$77	$83	$(47)	$36
State and local	(8)	(18)	(26)	8	(58)	(50)	39	(6)	33
Foreign	103	(101)	2	281	84	365	1,374	19	1,393
Total	$52	$(806)	$(754)	$304	$88	$392	$1,496	$(34)	$1,462

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

	Year Ended December 31,		
	2015	2014	2013
Statutory rate applied to income (loss) from continuing operations before income taxes	(35)%	35%	35%
Effects of foreign operations, including foreign tax credits	(2)	(6)	26
Change in permanent reinvestment assertion	—	(19)	—
Adjustments to valuation allowances	3	21	(1)
Change in tax law	5	—	—
Goodwill impairment	4	—	—
Other	—	(2)	1
Effective income tax expense (benefit) rate on continuing operations	(25)%	29%	61%

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The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. The difference between the total provision and the sum of the amounts allocated to segments appears in the "Not Allocated to Segments" column of the tables in Note 7.

Effects of foreign operations – The effects of foreign operations on our effective tax rate decreased in 2015 and 2014 as compared to 2013, due to a shift in pretax income mix between high and low tax jurisdictions. This is primarily related to decreased sales in Libya in 2015 and 2014 where the tax rate is in excess of 90%. Excluding Libya, the effective tax rates on continuing operations would be a benefit of 25% in 2015 and expense of 27% and 38% in 2014 and 2013.

Change in permanent reinvestment assertion – In the second quarter of 2015, we reviewed our operations and concluded that we do not have the same level of capital needs outside the U.S. as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings of approximately $1 billion associated with our Canadian operations to be permanently reinvested outside the U.S. We anticipate foreign tax credits associated with these Canadian earnings would be sufficient to offset any incremental U.S. tax liabilities, and therefore, no additional net deferred taxes were recorded in the second quarter of 2015. As such, none of Marathon Oil's foreign earnings remain permanently reinvested abroad.

In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations did not have the same level of immediate capital needs as previously expected. Therefore, we removed our assertion for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S. The U.K. statutory tax rate was in excess of the U.S. statutory tax rate and therefore foreign tax credits associated with these earnings exceeded any incremental U.S. tax liabilities.

Adjustments to valuation allowances – In 2015, 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 2015. Additionally, we increased the valuation allowance on deferred tax assets associated with our foreign operations as a result of pretax losses in certain jurisdictions. In 2014, we increased the valuation allowance against foreign tax credits as a result of removing the permanent reinvestment assertion on our U.K. operations since the U.K. statutory tax rate is in excess of the U.S. statutory tax rate per discussion above.

Change in tax law – On June 29, 2015, the Alberta government enacted legislation to increase the provincial corporate tax rate from 10% to 12%. As a result of this legislation, we recorded additional non-cash deferred tax expense of $135 million in the second quarter of 2015.

Deferred tax assets and liabilities resulted from the following:

	Year Ended December 31,	
(In millions)	2015	2014
Deferred tax assets:		
Employee benefits	$260	$364
Operating loss carryforwards	563	245
Capital loss carryforwards	17	89
Foreign tax credits	4,335	4,062
Other credit carryforwards	35	—
Investments in subsidiaries and affiliates	17	—
Other	73	116
Valuation allowances:		
Federal	(2,820)	(2,775)
State, net of federal benefit	(56)	(58)
Foreign	(162)	(108)
Total deferred tax assets	2,262	1,935
Deferred tax liabilities:		

Property, plant and equipment	3,376	3,737
Investments in subsidiaries and affiliates	—	66
Other	105	67
Total deferred tax liabilities	3,481	3,870
Net deferred tax liabilities	$1,219	$1,935

Tax carryforwards – At December 31, 2015 our operating loss carryforwards includes $365 million from the U.S. that expire in 2035. Foreign operating loss carryforwards include $863 million from Canada that expire in 2029 through 2035, $208 million from the Kurdistan Region of Iraq that expire in 2016 through 2020, $84 million from Libya that expires in 2025 and $81 million from E.G. that expire in 2017 through 2020. State operating loss carryforwards of $1,415 million expire in 2016 through 2035. Foreign tax credit carryforwards of $3,798 million expire in 2022 through 2025.

Valuation allowances – We consider whether it is more likely than not that some portion or all of our deferred tax assets will not be realized. In the event it is more likely than not that some portion or all of our deferred taxes will not be realized, such assets are reduced by a valuation allowance. The estimated realizability of the benefit of our deferred tax asset is based on certain estimates concerning future operating conditions (particularly as related to prevailing commodity prices), future financial conditions, income generated from foreign sources and our tax profile in the years that such operating loss carryforwards and tax credits may be claimed. Future increases to our valuation allowance are possible if our estimates and assumptions (particularly as they relate to downward revisions of our long-term commodity price forecasts) are revised such that they reduce estimates of future taxable income during the carryforward period.

Federal valuation allowances increased $45 million in 2015 related to U.S. benefits on foreign taxes accrued in 2015. Federal valuation allowances decreased $222 million in 2014 primarily due to the sale of our Norway and Angola businesses. Federal valuation allowances increased $930 million in 2013 related to U.S. benefits on foreign taxes accrued in that year.

Foreign valuation allowances increased $54 million in 2015 primarily due to deferred tax assets generated in the Kurdistan Region of Iraq, E.G. and Gabon. Foreign valuation allowances decreased $41 million in 2014 primarily due the disposal of our Angolan assets. Foreign valuation allowances decreased $61 million in 2013 primarily due to the disposal of our Indonesian assets.

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

	December 31,	
(In millions)	2015	2014
Assets:		
Other current assets	$—	$29
Other noncurrent assets	1,222	525
Liabilities:		
Other current liabilities	—	3
Noncurrent deferred tax liabilities	2,441	2,486
Net deferred tax liabilities	$1,219	$1,935

We elected to prospectively adopt Accounting Standards Update 2015-17, Balance Sheet Classification of Deferred Taxes, as of December 31, 2015, as disclosed in Note 2. Under this new guidance, we classify all deferred tax assets and liabilities and related valuation allowances as noncurrent. In accordance with a prospective adoption, we did not restate the balance sheet classification of deferred taxes for prior periods.

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. Such audits have been completed through the 2009 tax year. In November 2015, we received Notices of Proposed Adjustment related to our 2010-2011 tax years. We anticipate receiving the final agent's report in 2016. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

As of December 31, 2015 our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[a]	2004-2014
Canada	2010-2014
Equatorial Guinea	2007-2014
Libya	2012-2014
United Kingdom	2008-2014

[a] Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2015	2014	2013
Beginning balance	$80	$146	$98
Additions for tax positions related to the current year	—	—	14
Additions for tax positions of prior years	1	11	66
Reductions for tax positions of prior years	—	(68)	(25)
Settlements	(7)	(9)	(5)
Statute of limitations	(9)	—	(2)
Ending balance	$65	$80	$146

If the unrecognized tax benefits as of December 31, 2015 were recognized, $25 million would affect our effective income tax rate. As of December 31, 2015, there are no material uncertain tax positions for which it is reasonably possible that the amount would significantly increase or decrease during the next twelve months.

Interest and penalties are recorded as part of the tax provision and were $1 million, $6 million and $13 million related to unrecognized tax benefits in 2015, 2014 and 2013. As of December 31, 2015 and 2014, $14 million and $16 million of interest and penalties were accrued related to income taxes.

Pretax income (loss) from continuing operations included amounts attributable to foreign sources of $(654) million, $1,180 million and $2,336 million in 2015, 2014 and 2013.

10. Inventories

Liquid hydrocarbons, natural gas and bitumen are recorded at weighted average cost and carried at the lower of cost or market value. Supplies and other items consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

	December 31,	
(In millions)	2015	2014
Liquid hydrocarbons, natural gas and bitumen	$35	$58
Supplies and other items	278	299
Inventories at cost	$313	$357

11. Equity Method Investments and Related Party Transactions

During 2015, 2014 and 2013 only our equity method investees were considered related parties and they included:

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

Our equity method investments are summarized in the following table:

	Ownership as of	December 31,	
(In millions)	December 31, 2015	2015	2014
EGHoldings	60%	$603	$693
Alba Plant LLC	52%	230	225
AMPCO	45%	169	194
Other investments		1	1
Total		$1,003	$1,113

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $178 million in 2015, $451 million in 2014 and $435 million in 2013.

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Summarized financial information for equity method investees is as follows:

(In millions)	2015	2014	2013
Income data – year:			
Revenues and other income	$769	$1,349	$1,444
Income from operations	313	826	849
Net income	280	728	727
Balance sheet data – December 31:			
Current assets	$467	$639	
Noncurrent assets	1,317	1,451	
Current liabilities	211	371	
Noncurrent liabilities	41	39	

Revenues from related parties were $51 million, $56 million and $55 million in 2015, 2014 and 2013, with the majority related to EGHoldings in all years. Purchases from related parties were $207 million, $207 million and $242 million in 2015, 2014 and 2013 with the majority related to Alba Plant LLC in all years.

Current receivables from related parties at December 31, 2015 and 2014, were $29 million, and $31 million. Payables to related parties were $5 million and $11 million at December 31, 2015 and 2014, with the majority related to Alba Plant LLC.

12. Property, Plant and Equipment

	December 31,	
(In millions)	2015	2014
North America E&P	$15,226	$16,717
International E&P	2,533	2,741
Oil Sands Mining	9,197	9,455
Corporate	105	127
Net property, plant and equipment	$27,061	$29,040

Our Libya operations continue to be impacted by civil unrest. Operations were interrupted in mid-2013 as a result of the shutdown of the Es Sider crude oil terminal, and although temporarily re-opened during the second half of 2014, production remains shut-in through early 2016. Considerable uncertainty remains around the timing of future production and sales levels.

As of December 31, 2015, our net property, plant and equipment investment in Libya is approximately $777 million, and total proved reserves (unaudited) in Libya are 235 mmboe. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. Our periodic assessment of the carrying value of our net property, plant and equipment in Libya specifically considers the net investment in the assets, the duration of our concessions and the reserves anticipated to be recoverable in future periods. The undiscounted cash flows related to our Libya assets continue to exceed the carrying value of $777 million by a significant amount.

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Deferred exploratory well costs were as follows:

	December 31,		
(In millions)	2015	2014	2013
Amounts capitalized less than one year after completion of drilling	$352	$484	$512
Amounts capitalized greater than one year after completion of drilling	85	126	281
Total deferred exploratory well costs	$437	$610	$793
Number of projects with costs capitalized greater than one year after completion of drilling	2	3	7

(In millions)	2015	2014	2013
Beginning balance	$610	$793	$617
Additions	610	647	624
Charges to expense	(148)	(45)	(25)
Transfers to development	(635)	(579)	(414)
Dispositions[a]	—	(206)	(9)
Ending balance	$437	$610	$793

[a] Includes sale of Angola assets and Norway business in 2014.

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2015 are summarized by geographical area below:

(In millions)	
Gabon	$63
E.G.	22
Total	$85

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

Gabon - The Diaba-1B well reached total depth in the third quarter of 2013. Additional 3D seismic data was acquired in 2014 in the western part of the block and depth processing continued through 2015. We continue to utilize this data to facilitate evaluation of additional resource potential on the offshore Diaba License to support decisions regarding the exploration program, with drilling currently planned for 2017.

E.G. – The Corona well on Block D offshore E.G. was drilled in 2004, and we acquired an additional interest in the well in 2012. We plan to develop Block D through a unitization with the Alba field. Negotiations have been substantially completed and approval is expected in 2016.

13. Impairments and Exploration Expenses

During 2015, the continued decline of commodity prices resulted in downward revisions of our long-term commodity price assumptions and resulted in impairments of long-lived assets related to oil and gas producing properties. Further changes in management's forecast assumptions (including our Capital Program), or continued deterioration in commodity prices may cause us to reassess our long-lived assets and goodwill for impairment, and could result in impairment charges in the future.

Impairments

The following table summarizes impairment charges of proved properties:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Total impairments	$752	$132	$96

2015 - Impairments included $340 million million for the goodwill impairment of the North America E&P reporting unit, $335 million related to proved properties (primarily in Colorado and the Gulf of Mexico) as a result of lower forecasted

commodity prices, and $44 million associated with our disposition of natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma.
2014 - Impairments of $132 million consisted primarily of proved properties in the Gulf of Mexico, Texas and North Dakota as a result of revisions to estimated abandonment costs and lower forecasted commodity prices.
2013 - Impairments of $96 million included an impairment to the second LNG production train in E.G. as a result of a change in E.G.'s natural gas policy related to the country's resources for $40 million, a $15 million impairment of our Powder River Basin assets as a result of our decision to wind down operations and other impairments of long-lived assets as a result of reduced drilling expectations, reductions of estimated reserves or decreased commodity prices.
See Note 7 for relevant detail regarding segment presentation, Note 14 for further detail regarding the goodwill impairment and Note 15 for fair value measurements related to impairments of proved properties and long-lived assets.
Exploration expense
The following table summarizes the components of exploration expenses:

	Year Ended December 31,		
(In millions)	2015	2014	2013
Exploration Expenses			
Unproved property impairments	$964	$306	$572
Dry well costs	250	317	148
Geological and geophysical	31	85	80
Other	73	85	91
Total exploration expenses	$1,318	$793	$891

Unproved property impairments
2015 - Primarily due to changes in our conventional exploration strategy (Gulf of Mexico, Canadian in-situ assets and Harir block in the Kurdistan Region of Iraq), relinquishment of certain properties in the Gulf of Mexico, the operated Solomon exploration well in the Gulf of Mexico and our unproved property in Colorado as a result of the proved property impairment mentioned above.
2014 - Primarily consists of Eagle Ford and Bakken leases that either expired or we decided not to drill or extend.
2013 - Primarily consists of Eagle Ford leases that either expired or we decided not to drill or extend.
See Note 7 for relevant detail regarding segment presentation of unproved property impairments.
Dry well costs
2015 - Includes the operated Solomon exploration well in the Gulf of Mexico, our operated Sodalita West #1 exploratory well in E.G. and suspended well costs related our Canadian in-situ assets at Birchwood.
2014 - Includes the operated Key Largo well, outside-operated Perseus well and the outside operated second Shenandoah appraisal well, all of which are located in the Gulf of Mexico. In addition, 2014 also includes our exploration programs in Kurdistan Region of Iraq, Ethiopia and Kenya.
2013 - Primarily includes our exploration programs in Norway, Kurdistan Region of Iraq, Ethiopia, Kenya, Poland and Gulf of Mexico.

14. Goodwill
Goodwill is tested for impairment on an annual basis as of April 1 each year, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which only North America E&P and International E&P include goodwill. We estimated the fair values of the North America E&P and International E&P reporting units using a combination of market and income approaches. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. The market approach referenced observable inputs specific to us and our industry, such as the price of our common equity, our enterprise value, and valuation multiples of us and our peers from the investor analyst community. The

income approach utilized discounted cash flows, which were based on forecasted assumptions. Key assumptions to the income approach include: future liquid hydrocarbon and natural gas prices, estimated quantities of liquid hydrocarbon and natural gas proved and probable reserves, expected timing of production, discount rates, future capital requirements and operating expenses and tax rates. The assumptions used in the income approach are consistent with those that management uses to make business decisions. These valuation methodologies represent Level 3 fair value measurements. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in such assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

We performed our annual impairment tests as of April 1 in 2015, 2014 and 2013 and no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value. Subsequent to our goodwill impairment test in April 2015, triggering events (downward revisions to forecasted commodity price assumptions and sustained price declines in our common stock) required us to reassess our goodwill for impairment as of September 30, 2015 and December 31, 2015. We recorded an impairment of goodwill for the N.A. E&P reporting unit during the fourth quarter of 2015. While the fair value of our International E&P reporting unit exceeded book value, subsequent commodity price and/or common stock price declines may cause us to reassess our goodwill for impairment and could result in a non-cash impairment charge in the future.

The table below displays the allocated beginning goodwill balances by segment along with changes in the carrying amount of goodwill for 2015 and 2014:

(In millions)	N.A. E&P	Int'l E&P	OSM	Total
2014				
Beginning balance, gross	$347	$152	$1,412	$1,911
Less: accumulated impairments	—	—	(1,412)	(1,412)
Beginning balance, net	347	152	—	499
Dispositions	(3)	(37)	—	(40)
Ending balance, net	$344	$115	$—	$459
2015				
Beginning balance, gross	$344	$115	$1,412	$1,871
Less: accumulated impairments	—	—	(1,412)	(1,412)
Beginning balance, net	344	115	—	459
Dispositions	(4)	—	—	(4)
Impairment	(340)	—	—	(340)
Ending balance, net	$—	$115	$—	$115

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15. Fair Value Measurements
Fair values – Recurring
The following tables present assets and liabilities accounted for at fair value on a recurring basis by hierarchy level.

	December 31, 2015			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Commodity	$—	$51	$—	$51
Interest rate	—	8	—	8
Derivative instruments, assets	$—	$59	$—	$59
Derivative instruments, liabilities				
Commodity	$—	$1	$—	$1
Derivative instruments, liabilities	$—	$1	$—	$1

	December 31, 2014			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$—	$8	$—	$8
Derivative instruments, assets	$—	$8	$—	$8

Commodity derivatives include three-way collars, extendable three-way collars and call options. These instruments are measured at fair value using either the Black-Scholes Model or the Black Model. Inputs to both models include prices, interest rates and implied volatility. The inputs to these models are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. See Note 16 for additional discussion of the types of derivative instruments we use.
Fair values – Nonrecurring
The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2015		2014		2013	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$56	$412	$43	$132	$5	$96

Long-lived assets held for use that were impaired are discussed below. The fair values of each were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs, unless otherwise noted. Inputs to the fair value measurement include reserve and production estimates made by our reservoir engineers, estimated future commodity prices adjusted for quality and location differentials and forecasted operating expenses for the remaining estimated life of the reservoir.
North America E&P
In the third quarter of 2015, impairments of $333 million were recorded primarily related to certain producing assets in Colorado and the Gulf of Mexico as a result of lower forecasted commodity prices, to an aggregate fair value of $41 million.
During the second quarter of 2015, we recorded an impairment charge of $44 million related to East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets as a result of the anticipated sale (See Note 5). The fair values were measured using a probability weighted income approach based on both the anticipated sale price and held-for-use model.
In the third quarter of 2014, impairments of $53 million were recorded to Gulf of Mexico properties as a result of estimated abandonment cost and other revisions, to an aggregate fair value of $19 million. In addition, two fields were impaired a total of $47 million to an aggregate fair value of $24 million primarily due to lower forecasted commodity

prices.

The Ozona development in the Gulf of Mexico ceased production in 2013 and a $21 million impairment was recorded to write down the assets' remaining value. During 2014, we recorded additional impairments of $30 million as a result of abandonment cost revisions.

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Other impairments of long-lived assets held for use in 2015, 2014 and 2013 were a result of reduced drilling expectations, reductions of estimated reserves or decreased commodity prices.

International E&P

In the third quarter of 2015, a partial impairment of $12 million was recorded to an investment in an equity method investee as a result of lower forecasted commodity prices, to a fair value of $604 million. The impairment was reflected in income from equity method investments in our consolidated statement of income.

In the fourth quarter of 2013, as a result of E.G.'s natural gas policy related to the country's resources, we elected to cease our efforts to develop a second LNG production train on Bioko Island and recorded a $40 million impairment of all capitalized costs associated with engineering and feasibility studies. In addition, our share of income from EGHoldings included a $4 million impairment related to the same project, reflected in income from equity method investments in the 2013 consolidated statement of income.

Oil Sands Mining

In the fourth quarter of 2015, impairments of $26 million were recorded related to long-lived assets used in outside operated debottlenecking projects. Based on an evaluation by the operator, it was determined that the projects would not continue due to a need to reduce capital intensity and improve efficiency.

Fair values – Financial instruments

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

The following table summarizes financial instruments, excluding receivables, commercial paper, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at December 31, 2015 and 2014.

	December 31,			
	2015		2014	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$104	$118	$132	$129
Total financial assets	$104	$118	$132	$129
Financial liabilities				
Other current liabilities	$34	$33	$13	$13
Long-term debt, including current portion[(a)]	6,723	7,291	6,887	6,360
Deferred credits and other liabilities	97	95	69	68
Total financial liabilities	$6,854	$7,419	$6,969	$6,441

(a) Excludes capital leases.

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

Most of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value of such debt. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

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16. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we use and the reasons for them. All of our interest rate and commodity derivatives are subject to enforceable master netting arrangements or similar agreements under which we may report net amounts. The following tables present the gross fair values of derivative instruments and the reported net amounts along with where they appear on the consolidated balance sheets.

	December 31, 2015			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$8	$—	$8	Other noncurrent assets
Total Designated Hedges	$8	$—	$8	
Not Designated as Hedges				
Commodity	$51	$1	$50	Other current assets
Total Not Designated as Hedges	$51	$1	$50	
Total	$59	$1	$58	

	December 31, 2014			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$8	$—	$8	Other noncurrent assets
Total Designated Hedges	$8	$—	$8	

Derivatives Designated as Fair Value Hedges

The following table presents by maturity date, information about our interest rate swap agreements, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

	December 31, 2015		December 31, 2014	
Maturity Dates	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate
October 1, 2017	$600	4.73 %	$600	4.64 %
March 15, 2018	$300	4.66 %	$300	4.49 %

The pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income is summarized in the table below. There is no ineffectiveness related to the fair value hedges.

		Gain (Loss) Year Ended December 31,		
(In millions)	Income Statement Location	2015	2014	2013
Derivative				
Interest rate	Net interest and other	$—	$—	$(13)
Foreign currency	Discontinued operations	—	(36)	(44)
Hedged Item				
Long-term debt	Net interest and other	$—	$—	$13
Accrued taxes	Discontinued operations	—	36	44

The table above reflects foreign currency forwards that hedged the current Norwegian tax liability of our Norway business, which was reported as discontinued operations. The open positions were transferred to the purchaser of our Norway business upon closing of the sale in the fourth quarter of 2014.

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Derivatives Not Designated as Hedges

During 2015, we entered into multiple crude oil derivatives indexed to NYMEX WTI related to a portion of our forecasted North America E&P sales through December 2016. These commodity derivatives consist of three-way collars, extendable three-way collars and call options. Three way-collars consist of a sold call (ceiling), a purchased put (floor) and a sold put. The ceiling price is the maximum we will receive for the contract crude oil volumes, the floor is the minimum price we will receive, unless the market price falls below the sold put strike price. In this case, we receive the NYMEX WTI price plus the difference between the floor and the sold put price. These commodity derivatives are shown in the table below:

Financial Instrument	Weighted Average Price	Barrels per day	Remaining Term
Three-Way Collars			
Ceiling	\$60.03	10,000	January - March 2016 [(a)]
Floor	\$50.20		
Sold put	\$41.60		
Ceiling	\$71.84	12,000	January- December 2016
Floor	\$60.48		
Sold put	\$50.00		
Ceiling	\$73.13	2,000	January- June 2016 [(b)]
Floor	\$65.00		
Sold put	\$50.00		
Sold Call Options	\$72.39	10,000	January- December 2016 [(c)]

(a) Counterparties have the option, exercisable on March 31, 2016, to extend these collars through September of 2016 at the same volume and weighted average price as the underlying three-way collars.

(b) Counterparty has the option, exercisable on June 30, 2016, to extend these collars through the remainder of 2016 at the same volume and weighted average price as the underlying three-way collars.

(c) Call options settle monthly.

The impact of these crude oil derivative instruments appears in sales and other operating revenues in our consolidated statements of income and was a net gain of \$128 million year to date December 31, 2015. There were no crude oil derivative instruments during 2014.

On June 1, 2015, we entered into Treasury rate locks, which expired on the same day, to hedge against timing differences as it related to our Notes offering (see Note 17). Following the execution of the Treasury locks, corresponding interest rates increased during the day of June 1. As a result, the settlement of the Treasury rate locks resulted in a gain of \$6 million, which was recognized in net interest and other in our consolidated statements of income.

17. Debt

Short-term debt

As of December 31, 2015, we had no borrowings against our unsecured revolving credit facility (as amended, the "Credit Facility"), as described below, or under our U.S. commercial paper program that is backed by the Credit Facility.

Revolving Credit Facility

In May 2015, we amended our \$2.5 billion Credit Facility to increase by \$500 million to a total of \$3 billion and extended the maturity date by an additional year such that the Credit Facility now matures in May 2020. The amendment additionally provides us the ability to request two one-year extensions to the maturity date and an option to increase the commitment amount by up to an additional \$500 million, subject to the consent of any increasing lenders. The sub-facilities for swing-line loans and letters of credit remain unchanged allowing up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender, as well as the borrowing options under the Credit Facility, remain unchanged.

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The Credit Facility includes a covenant requiring that our ratio of total debt to total capitalization not exceed 65% as of the last day of each fiscal quarter. If an event of default occurs, the lenders holding more than half of the commitments may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility. As of December 31, 2015, we were in compliance with this covenant with a debt-to-capitalization ratio of 28%.

Long-term debt

The following table details our long-term debt:

	December 31,	
(In millions)	2015	2014
Senior unsecured notes:		
0.900% notes due 2015	$—	$1,000
6.000% notes due 2017[(a)]	682	682
5.900% notes due 2018[(a)]	854	854
7.500% notes due 2019[(a)]	228	228
2.700% notes due 2020[(a)]	600	—
2.800% notes due 2022[(a)]	1,000	1,000
9.375% notes due 2022 [(b)]	32	32
Series A notes due 2022 [(b)]	3	3
8.500% notes due 2023 [(b)]	70	70
8.125% notes due 2023 [(b)]	131	131
3.850% notes due 2025[(a)]	900	—
6.800% notes due 2032[(a)]	550	550
6.600% notes due 2037[(a)]	750	750
5.200% notes due 2045[(a)]	500	—
Capital leases:		
Capital lease obligation of consolidated subsidiary due 2016 – 2049	9	9
Other obligations:		
4.550% promissory note, semi-annual payments due 2015	—	68
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Total[(b)]	7,309	6,377
Unamortized discount	(10)	(8)
Fair value adjustments[(c)]	17	22
Unamortized debt issuance cost [(d)]	(39)	(28)
Amounts due within one year	(1)	(1,068)
Total long-term debt	$7,276	$5,295

(a) These notes contain a make-whole provision allowing us to repay the debt at a premium to market price.
(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $236 million at December 31, 2015 may be declared immediately due and payable.
(c) See Notes 15 and 16 for information on interest rate swaps.
(d) After the adoption of the debt issuance costs standard, these costs are now reflected as a direct reduction from the associated debt liability in our consolidated balance sheets. See Note 2 for information.

Debt Issuance On June 10, 2015, we issued $2 billion aggregate principal amount of unsecured senior notes which consist of the following series:

- $600 million of 2.70% senior notes due June 1, 2020
- $900 million of 3.85% senior notes due June 1, 2025
- $500 million of 5.20% senior notes due June 1, 2045

Interest on each series of senior notes is payable semi-annually beginning December 1, 2015. We may redeem some or all of the senior notes at any time at the applicable redemption price, plus accrued interest, if any. The aggregate net proceeds were used to repay our $1 billion 0.90% senior notes that matured in November 2015, and the remainder for general corporate purposes. As of December 31, 2015, we were in compliance with the covenants under the indenture governing the senior notes.

The following table shows future long-term debt payments:

(In millions)	
2016	$1
2017	682
2018	854
2019	228
2020	600
Thereafter	4,944
Total long-term debt, including current portion	$7,309

18. Asset Retirement Obligations

Asset retirement obligations primarily consist of estimated costs to remove, dismantle and restore land or seabed at the end of oil and gas production operations, including bitumen mining operations. Changes in asset retirement obligations were as follows:

	For Year Ended December 31,	
(In millions)	2015	2014
Beginning balance	$1,958	$2,096
Incurred liabilities, including acquisitions	47	89
Settled liabilities, including dispositions	(289)	(426)
Accretion expense (included in depreciation, depletion and amortization)	105	104
Revisions of estimates	(132)	95
Held for sale	(54)	—
Ending balance	$1,635	$1,958

2015

Settled liabilities include dispositions, primarily in the Gulf of Mexico and the East Texas, North Louisiana and Wilburton, Oklahoma as well as retirements in the Gulf of Mexico and the U.K.

Revisions of estimates were primarily due to changes in timing of activities in the U.K. and lower estimated costs across the assets.

Held for sale is related to the Neptune field in the Gulf of Mexico.

Ending balance includes $34 million classified as short-term at December 31, 2015.

2014

Settled liabilities included the Norway and Angola dispositions.

Ending balance includes $41 million classified as short-term at December 31, 2014.

19. Supplemental Cash Flow Information

	Year Ended December 31,		
(In millions)	2015	2014	2013
Net cash used in operating activities:			
Interest paid (net of amounts capitalized)	$(325)	$(279)	$(289)
Income taxes paid to taxing authorities [(a)]	(171)	(1,679)	(3,904)
Net cash provided by (used in) financing activities:			
Commercial paper, net:			
Issuances	$—	$2,345	$10,870
Repayments	—	(2,480)	(10,935)
Commercial paper, net	$—	$(135)	$(65)
Noncash investing activities, related to continuing operations:			
Asset retirement cost increase (decrease)	$(85)	$151	$290
Increase in capital expenditure accrual	—	335	6
Asset retirement obligations assumed by buyer	251	359	92

(a) Income taxes paid to taxing authorities includes $1,312 million and $2,270 million in 2014, and 2013 related to discontinued operations.

20. Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in the U.K and E.G. Benefits under these plans are based on plan provisions specific to each plan. For the U.K. pension plan, a final decision was reached with the plan trustees to close the plan to future benefit accruals effective December 31, 2015.

We also have defined benefit plans for other postretirement benefits covering our U.S. employees. Health care benefits are provided up to age 65 through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Post-age 65 health care benefits are provided to U.S. employees on a defined contribution basis. Life insurance benefits are provided to certain retiree beneficiaries. These other postretirement benefits are not funded in advance.

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

	Pension Benefits				Other Benefits	
	2015		2014		2015	2014
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.
Accumulated benefit obligation	518	579	793	610	260	279
Change in benefit obligations:						
Beginning balance	$894	$651	$933	$649	$279	$279
Service cost	29	14	31	16	3	3
Interest cost	25	25	35	27	11	13
Plan amendment[a]	(88)	1	—	—	—	(42)
Actuarial loss (gain)[b]	26	(29)	174	46	(20)	42
Foreign currency exchange rate changes	—	(35)	—	(39)	—	—
Divestiture[c]	—	—	—	(29)	—	—
Liability (gain)/loss due to curtailment[d]	(18)	(23)	—	—	2	—
Settlements paid	(335)	—	(271)	—	—	—
Benefits paid	(8)	(25)	(8)	(19)	(15)	(16)
Ending balance	$525	$579	$894	$651	$260	$279
Change in fair value of plan assets:						
Beginning balance	$574	$622	$625	$597	$—	$—
Actual return on plan assets	8	8	59	59	—	—
Employer contributions	115	36	169	37	15	16
Foreign currency exchange rate changes	—	(33)	—	(39)	—	—
Divestiture[c]	—	—	—	(13)	—	—
Settlements paid	(335)	—	(271)	—	—	—
Benefits paid	(8)	(25)	(8)	(19)	(15)	(16)
Ending balance	$354	$608	$574	$622	$—	$—
Funded status of plans at December 31	$(171)	$29	$(320)	$(29)	$(260)	$(279)
Amounts recognized in the consolidated balance sheets:						
Noncurrent assets	—	29	—	—	—	—
Current liabilities	(8)	—	(11)	—	(20)	(19)
Noncurrent liabilities	(163)	—	(309)	(29)	(240)	(260)
Accrued benefit cost	$(171)	$29	$(320)	$(29)	$(260)	$(279)
Pretax amounts in accumulated other comprehensive loss:						
Net loss (gain)	$171	$61	$283	$91	$14	$34
Prior service cost (credit)	(65)	4	10	8	(28)	(41)

(a) The plan amendment in 2015 was a freeze of the final average pay used in the legacy formula of the defined benefit pension plan. Activity in 2014 represents a change in plan design related to the health care benefits provided under the postretirement plan.

(b) Activity in 2014 includes the increase in the U.S. pension and postretirement benefit obligations of $13 million and $15 million respectively, due to the adoption of the 2014 mortality table.

(c) Related to the sale of our Norway business in the fourth quarter of 2014.

(d) Related to workforce reductions, which reduced the future expected years of service for employees participating in the plans and the impact of discontinuing accruals for future benefits under the U.K. pension plan effective December 31, 2015.

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

	Pension Benefits						Other Benefits		
	Year Ended December 31,						Year Ended December 31,		
	2015		2014		2013		2015	2014	2013
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.	U.S.
Components of net periodic benefit cost:									
Service cost	$29	$14	$31	$16	$33	$17	$3	$3	$4
Interest cost	25	25	35	27	40	23	11	13	12
Expected return on plan assets	(30)	(37)	(34)	(32)	(43)	(24)	—	—	—
Amortization:									
- prior service cost (credit)	(7)	1	5	1	6	1	(4)	(6)	(6)
- actuarial loss	22	2	29	1	43	4	1	—	—
Net curtailment loss (gain)[(a)]	(5)	4	—	—	—	—	(7)	—	—
Net settlement loss[(b)]	119	—	99	—	45	—	—	—	—
Net periodic benefit cost[(c)]	$153	$9	$165	$13	$124	$21	$4	$10	$10
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)[(d)]	$30	$(25)	$149	$33	$(161)	$(15)	$(21)	$42	$(31)
Amortization of actuarial gain (loss)	(134)	(2)	(128)	(1)	(88)	(4)	(1)	—	—
Prior service cost (credit)	(89)	1	—	—	—	—	—	(42)	—
Amortization of prior service credit (cost)	7	(5)	(5)	(1)	(6)	(1)	13	6	6
Total recognized in other comprehensive (income) loss	$(186)	$(31)	$16	$31	$(255)	$(20)	$(9)	$6	$(25)
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$(33)	$(22)	$181	$44	$(131)	$1	$(5)	$16	$(15)

(a) Related to workforce reductions, which reduced the future expected years of service for employees participating in the plans and the impact of discontinuing accruals for future benefits under the U.K. pension plan effective December 31, 2015.

(b) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. pension plans in all periods presented.

(c) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

(d) Activity in 2014 includes the impact of the sale of our Norway business in the fourth quarter of 2014.

The estimated net loss and prior service credit for our defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are $12 million and $11 million. The estimated prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 is $3 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2015, 2014 and 2013.

	Pension Benefits						Other Benefits		
	2015		2014		2013		2015	2014	2013
(In millions)	U.S.	Int’l	U.S.	Int’l	U.S.	Int’l	U.S.	U.S.	U.S.
Weighted average assumptions used to determine benefit obligation:									
Discount rate	4.04 %	3.90 %	3.71 %	3.70 %	4.28 %	4.60 %	4.36 %	4.01 %	4.85 %
Rate of compensation increase [(a)]	4.00 %	—	4.00 %	3.60 %	5.00 %	4.90 %	4.00 %	4.00 %	5.00 %
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	3.79 %	3.70 %	3.98 %	4.60 %	3.79 %	4.40 %	3.93 %	4.69 %	4.06 %
Expected long-term return on plan assets	6.75 %	5.70 %	6.75 %	5.70 %	7.25 %	4.90 %	—	—	—
Rate of compensation increase	4.00 %	3.60 %	5.00 %	4.90 %	5.00 %	4.50 %	4.00 %	5.00 %	5.00 %

(a) No future benefits will be incurred for the UK plan after December 31, 2015. Therefore, rate of compensation increase is no longer applicable to this plan.

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Expected long-term return on plan assets – The expected long-term return on plan assets assumption for our U.S. funded plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group which utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan's asset allocation. To determine the expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation to develop the overall expected long-term return on plan assets assumption.
Assumed weighted average health care cost trend rates

	2015		2014		2013	
Initial health care trend rate	8.00	%	6.88	%	6.89	%
Ultimate trend rate	4.50	%	5.00	%	5.00	%
Year ultimate trend rate is reached	2024		2024		2020	

Employer provided subsidy for post-65 retiree health care coverage will only increase by the consumer price index (not to exceed 4%) each year. Company contributions are funded to a Health Reimbursement Account on the retiree's behalf to subsidize the retiree's cost of obtaining health care benefits through a private exchange. Therefore, a 1% change in health care cost trend rates would not have a material impact on either the service and interest cost components and the postretirement benefit obligations.
Plan investment policies and strategies – The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with applicable legal requirements; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plan's investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.
U.S. plan – The plan's current targeted asset allocation is comprised of 55% equity securities and 45% other fixed income securities. Over time, as the plan's funded ratio (as defined by the investment policy) improves, in order to reduce volatility in returns and to better match the plan's liabilities, the allocation to equity securities will decrease while the amount allocated to fixed income securities will increase. The plan's assets are managed by a third-party investment manager.
International plan – Our international plan's target asset allocation is comprised of 61% equity securities and 39% fixed income securities. The plan assets are invested in eight separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers whose performance is measured independently by a third-party asset servicing consulting firm.
Fair value measurements – Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2015 and 2014.
Cash and cash equivalents – Cash and cash equivalents are valued using a market approach and are considered Level 1. This investment also includes a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2.
Equity securities – Investments in common stock, preferred stock, and real estate investment trusts ("REIT") are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership. These private equity investments are considered Level 3. Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and are therefore considered Level 1. Investments in pooled funds are valued using a market approach at the net asset value ("NAV") of units held. The various funds consist of either an equity or fixed income investment

portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These are considered Level 2.

Fixed income securities – Fixed income securities are valued using a market approach. U.S. treasury notes and exchange traded funds ("ETFs") are valued at the closing price reported in an active market and are considered Level 1. Corporate bonds and other bonds are valued using calculated yield curves created by models that incorporate various market factors. Primarily investments are held in U.S. and non-U.S. corporate bonds in diverse industries and are considered Level 2. Other bonds primarily consist of securities issued by governmental agencies and municipalities. The investment in the commingled fund is valued using the NAV of units held and is considered Level 2. The commingled fund consists of an equity and fixed income portfolio with underlying investments held in U.S. and non-U.S. securities. Pooled funds primarily have investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds.

Other – Other investments are comprised of an international insurance carrier contract and the majority of the underlying investments consist of a mix of non-U.S. publicly traded equity securities valued at the closing price reported in an active market and fixed income securities valued using calculated yield curves. This asset is considered Level 2. The other investments, an unallocated annuity contract, two limited liability companies and real estate are considered Level 3, as significant inputs to determine fair value are unobservable.

The following tables present the fair values of our defined benefit pension plan's assets, by level within the fair value hierarchy, as of December 31, 2015 and 2014.

	December 31, 2015							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int’l	U.S.	Int’l	U.S.	Int’l	U.S.	Int’l
Cash and cash equivalents	$47	$6	$1	$—	$—	$—	$48	$6
Equity securities:								
Common and preferred stock	115	—	—	—	—	—	115	—
REIT and private equity	1	—	—	—	23	—	24	—
Mutual and pooled funds	—	218	—	152	—	—	—	370
Fixed income securities:								
U.S. treasury notes and ETFs	12	—	—	—	—	—	12	—
Corporate and other bonds	—	—	105	—	—	—	105	—
Commingled and pooled funds	—	—	23	232	—	—	23	232
REIT and swaps	—	—	2	—	—	—	2	—
Other	—	—	—	—	25	—	25	—
Total investments, at fair value	$175	$224	$131	$384	$48	$—	$354	$608

	December 31, 2014							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int’l	U.S.	Int’l	U.S.	Int’l	U.S.	Int’l
Cash and cash equivalents	$26	$1	$—	$—	$—	$—	$26	$1
Equity securities:								
Common and preferred stock	230	—	—	—	—	—	230	—
REIT and private equity	—	—	—	—	25	—	25	—
Mutual and pooled funds	—	221	—	164	—	—	—	385
Fixed income securities:								
U.S. treasury notes and ETFs	33	—	—	—	—	—	33	—
Corporate and other bonds	—	—	190	—	—	—	190	—
Commingled and pooled funds	—	—	40	236	—	—	40	236
Other	—	—	—	—	30	—	30	—
Total investments, at fair value	$289	$222	$230	$400	$55	$—	$574	$622

The activity during the year ended December 31, 2015 and 2014, for the assets using Level 3 fair value measurements was immaterial.

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Estimated future benefit payments – The following gross benefit payments, which were estimated based on actuarial assumptions applied at December 31, 2015 and reflect expected future services, as appropriate, are to be paid in the years indicated.

	Pension Benefits		Other Benefits
(In millions)	U.S.	Int’l	U.S.
2016	$61	$16	$21
2017	61	17	21
2018	59	20	20
2019	55	21	20
2020	53	22	20
2021 through 2025	224	125	89

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $62 million in 2016. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $8 million and $21 million in 2016.

Contributions to defined contribution plans – We contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $20 million, $25 million and $27 million in 2015, 2014 and 2013.

Additional Severance Obligation – We expect to make severance payments of approximately $8 million in 2016 related to the workforce reduction in 2015.

21. Incentive Based Compensation

Description of stock-based compensation plans – The Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") was approved by our stockholders in April 2012 and authorizes the Compensation Committee of the Board of Directors to grant stock options, SARs, stock awards (including restricted stock and restricted stock unit awards) and performance unit awards to employees. The 2012 Plan also allows us to provide equity compensation to our non-employee directors. No more than 50 million shares of our common stock may be issued under the 2012 Plan. For stock options and SARs, the number of shares available for issuance under the 2012 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted. For stock awards (including restricted stock and restricted stock unit awards), the number of shares available for issuance under the 2012 Plan will be reduced by 2.41 shares for each share of our common stock in respect of which the award is granted.

Shares subject to awards under the 2012 Plan that are forfeited, are terminated or expire unexercised become available for future grants. In addition, the number of shares of our common stock reserved for issuance under the 2012 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2012 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2012 Plan, no new grants were or will be made from any prior plans. Any awards previously granted under any prior plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock-based awards under the plans

Stock options – We grant stock options under the 2012 Plan. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. In general, our stock options vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

SARs - At December 31, 2015, there are no SARs outstanding.

Restricted stock – We grant restricted stock under the 2012 Plan. The restricted stock awards granted to officers generally vest three years from the date of grant, contingent on the recipient’s continued employment. We also grant restricted stock to certain non-officer employees based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest ratably over a three-year period, contingent on the recipient’s continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares of restricted stock are not transferable and are held by our transfer agent.

Stock-based performance units – Beginning in 2013, we grant stock-based performance units to officers under the 2012 Plan. At the grant date, each unit represents the value of one share of our common stock. These units are settled in cash, and the amount of the payment is based on (1) the vesting percentage, which can be from zero to 200% based on performance achieved and (2) the value of our common stock on the date vesting is determined by the Compensation Committee of the Board of Directors. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of our Board of Directors. Dividend equivalents may accrue during the performance period and would be paid in cash at the end of the performance period based on the number of shares that would represent the value of the units.

Restricted stock units – We maintain an equity compensation program for our non-employee directors under the 2012 Plan. All non-employee directors receive annual grants of common stock units. Common shares will be issued for units granted on or after January 1, 2012 upon completion of board service or three years from the date of grant, whichever is earlier. Any units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. We also grant restricted stock units to certain non-officer international employees which generally vest ratably over a three-year period, contingent on the recipient's continued employment. Grants of restricted stock units to these non-officer international employees are based on their performance and for retention purposes. Common shares will be issued for these restricted stock units after vesting. Prior to vesting, recipients of restricted stock units typically receive dividend equivalent payments, but they may not vote.

Total stock-based compensation expense – Total employee stock-based compensation expense was $57 million, $70 million and $70 million in 2015, 2014 and 2013, while the total related income tax benefits were $20 million, $25 million and $25 million in the same years. In 2015, 2014 and 2013, cash received upon exercise of stock option awards was $9 million, $136 million and $58 million. Tax benefits realized for deductions for stock awards settled during 2014 and 2013 totaled $51 million and $36 million. There were no tax benefits realized for deductions for stock awards settled during 2015.

Stock option awards – During 2015, we granted stock option awards to officer employees. During 2014 and 2013, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following weighted average Black-Scholes assumptions:

	2015		2014		2013	
Exercise price per share	$29.06		$34.49		$33.54	
Expected annual dividend yield	2.9	%	2.3	%	2.1	%
Expected life in years	6.2		5.9		6.1	
Expected volatility	32	%	38	%	38	%
Risk-free interest rate	1.7	%	1.8	%	1.6	%
Weighted average grant date fair value of stock option awards granted	$6.84		$10.50		$10.25	

The following is a summary of stock option award activity in 2015.

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Average Intrinsic Value (in millions)
Outstanding at beginning of year	13,427,836	$29.68		
Granted	724,082	$29.06		
Exercised	(553,401)	$16.85		
Canceled	(933,098)	$32.99		
Outstanding at end of year	12,665,419	$29.97	4 years	$—
Exercisable at end of year	10,654,799	$29.50	3 years	$—
Expected to vest	1,996,175	$32.45	8 years	$—

The intrinsic value of stock option awards exercised during 2015, 2014 and 2013 was $6 million, $83 million and $35 million.

As of December 31, 2015, unrecognized compensation cost related to stock option awards was $9 million, which is expected to be recognized over a weighted average period of one year.

Restricted stock awards and restricted stock units – The following is a summary of restricted stock and restricted stock unit award activity in 2015.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	3,448,353	$34.04
Granted	2,994,558	$28.90
Vested & Exercised	(1,350,344)	$33.40
Canceled	(1,075,223)	$32.70
Unvested at end of year	4,017,344	$30.76

The vesting date fair value of restricted stock awards which vested during 2015, 2014 and 2013 was $26 million, $70 million and $59 million. The weighted average grant date fair value of restricted stock awards was $30.76, $34.04 and $31.80 for awards unvested at December 31, 2015, 2014 and 2013.

As of December 31, 2015 there was $86 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of one year.

Stock-based performance unit awards – During 2015, 2014 and 2013 we granted 382,335, 221,491 and 353,600 stock-based performance unit awards to officers. At December 31, 2015, there were 584,566 units outstanding.

The key assumptions used in the Monte Carlo simulation to determine the fair value of stock-based performance units granted in 2015, 2014 and 2013 were:

	2015	2014	2013
Valuation date stock price	$12.59	$12.59	$12.98
Expected annual dividend yield	1.5 %	1.5 %	1.5 %
Expected volatility	37 %	46 %	62 %
Risk-free interest rate	1.1 %	0.7 %	0.1 %
Fair value of stock-based performance units outstanding	$7.08	$6.04	$0.18

Cash-based performance unit awards – Prior to 2013, cash-based performance unit awards were granted to officers that provide a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our TSR as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with a maximum payout of $2 per unit, but the actual payout could be anywhere between zero and the maximum. Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards.

During 2012, we granted 12.7 million performance units, all having a 36-month performance period. During the third quarter of 2011, we granted 15 million performance units, a portion of which had a 30-month performance period and a portion of which had an 18-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spin-off. Compensation expense associated with cash-based performance units was $5 million and $9 million in 2014 and 2013. At December 31, 2014 all performance periods ended and no additional units have been granted.

22. Reclassifications Out of Accumulated Other Comprehensive Loss

The following table presents a summary of amounts reclassified from accumulated other comprehensive loss to income (loss) from continuing operations in their entirety:

(In millions)	Year Ended December 31, 2015	2014	Income Statement Line
Postretirement and postemployment plans			
Amortization of actuarial loss	$(24)	$(30)	General and administrative
Net settlement loss	(119)	(99)	General and administrative
Net curtailment gain	8	—	General and administrative
	(135)	(129)	Income (loss) from operations
	51	62	Provision for income taxes
Other insignificant items, net of tax	—	(1)	
Total reclassifications	$(84)	$(68)	Income (loss) from continuing operations

23. Stockholders' Equity

In 2014 we acquired 29 million common shares at a cost of $1 billion under our share repurchase program, initially authorized in 2006, bringing our total repurchases to 121 million common shares at a cost of $4.7 billion. As of December 31, 2015 the total remaining share repurchase authorization was $1.5 billion. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables.

24. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations and for operating lease obligations having noncancellable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2016	$1	$30
2017	1	26
2018	1	24
2019	1	24
2020	1	24
Later years	16	30
Sublease rentals	—	(1)
Total minimum lease payments	$21	$157
Less imputed interest costs	(12)	
Present value of net minimum lease payments	$9	

Operating lease rental expense related to continuing operations was $104 million, $120 million and $105 million in 2015, 2014 and 2013.

25. Commitments and Contingencies

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

Environmental matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2015 and 2014, accrued liabilities for remediation were not significant. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees – We have entered into a performance guarantee related to asset retirement obligations with aggregate maximum potential undiscounted payments totaling $31 million as of December 31, 2015. Under the terms of this guarantee arrangement, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements.

Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contract commitments – At December 31, 2015 and 2014, contractual commitments to acquire property, plant and equipment totaled $371 million and $747 million.

In connection with the sale of our operated producing properties in the greater Ewing Bank area and non-operated producing interests in the Petronius and Neptune fields in the Gulf of Mexico, we retained an overriding royalty interest in the properties. As part of the sale agreement, proceeds associated with the production of our override, up to $70 million, are dedicated solely to the satisfaction of the corresponding future abandonment obligations of the properties. The term of our override ends once sales proceeds equal $70 million.

Select Quarterly Financial Data (Unaudited)

	2015				2014			
(In millions, except per share data)	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues	$1,484	$1,490	$1,384	$1,164	$2,690	$2,888	$2,870	$2,398
Income (loss) from continuing operations before income taxes	(420)	(392)	(1,145)	(1,001)	598	511	453	(201)
Income (loss) from continuing operations	(276)	(386)	(749)	(793)	398	360	304	(93)
Discontinued operations [a]	—	—	—	—	751	180	127	1,019
Net income (loss)	$(276)	$(386)	$(749)	$(793)	$1,149	$540	$431	$926
Income (loss) per share:								
Basic:								
Continuing operations	$(0.41)	$(0.57)	$(1.11)	$(1.17)	$0.58	$0.53	$0.45	$(0.14)
Discontinued operations [a]	—	—	—	—	$1.08	$0.27	$0.19	$1.51
Net income (loss)	($0.41)	($0.57)	($1.11)	($1.17)	$1.66	$0.80	$0.64	$1.37
Diluted:								
Continuing operations	($0.41)	($0.57)	($1.11)	($1.17)	$0.57	$0.53	$0.45	($0.14)
Discontinued operations [a]	—	—	—	—	$1.08	$0.27	$0.19	$1.51
Net income (loss)	($0.41)	($0.57)	($1.11)	($1.17)	$1.65	$0.80	$0.64	$1.37
Dividends paid per share	$0.21	$0.21	$0.21	$0.05	$0.19	$0.19	$0.21	$0.21

[a] We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014. The Angola assets and Norway business are reflected as discontinued operations in 2014.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the U.S.; Canada; E.G.; Other Africa, which primarily includes activities in Gabon, Kenya, Ethiopia and Libya; and Other International ("Other Int'l"), which includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our Angola assets and our Norway business in 2014, and both are shown as discontinued operations ("Disc Ops") in prior periods.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of crude oil and condensate, natural gas liquids, natural gas and synthetic crude oil is a highly technical process which is based upon several underlying assumptions that are subject to change. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Estimates – Estimated Quantities of Net Reserves. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business – Reserves.

Our December 31, 2015 proved reserves were calculated using the SEC pricing. The table below provides the 2015 SEC pricing of the benchmark prices as well as the unweighted average for the first two months of 2016:

	SEC Pricing 2015	2-month Average 2016
WTI Crude oil	$50.28	$34.19
Henry Hub natural gas	$2.59	$2.28
Brent crude oil	$54.25	$34.86
Natural gas liquids	$17.32	$12.87

When determining the December 31, 2015 proved reserves for each property, the SEC prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

Beginning in the second half of 2014, the crude oil and natural gas benchmarks began to decline and these declines continued through 2015 and into 2016. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves.

Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing the reserves as of the end of the year. The decline in commodity prices prompted a concerted effort to reduce the costs of developing and producing reserves. Therefore, the impact of sustained reduced commodity prices on future cash flows will be partially offset by the resulting lower costs to develop and produce reserves.

A sustained period of lower commodity prices could also cause us to decrease our near term capital programs and defer investments until prices improve. A shifting of capital expenditures into future periods beyond five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. See Item 1A. Risk Factors for a further discussion of how a substantial extended decline in commodity prices could impact us.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Crude oil and condensate								
Proved developed and undeveloped reserves:								
Beginning of year - 2013	387	—	72	209	24	692	82	774
Revisions of previous estimates	33	—	(1)	12	6	50	19	69
Improved recovery	—	—	—	—	—	—	11	11
Purchases of reserves in place	12	—	—	—	—	12	—	12
Extensions, discoveries and other additions	112	—	1	3	—	116	8	124
Production	(46)	—	(8)	(9)	(5)	(68)	(29)	(97)
Sales of reserves in place	(1)	—	—	—	—	(1)	—	(1)
End of year - 2013	497	—	64	215	25	801	91	892
Revisions of previous estimates	36	—	(1)	(4)	1	32	10	42
Improved recovery	2	—	—	—	—	2	—	2
Purchases of reserves in place	6	—	—	—	—	6	—	6
Extensions, discoveries and other additions	153	—	1	—	7	161	3	164
Production	(57)	—	(7)	(3)	(4)	(71)	(17)	(88)
Sales of reserves in place	(3)	—	—	—	—	(3)	(87)	(90)
End of year - 2014	634	—	57	208	29	928	—	928
Revisions of previous estimates	(109)	—	2	(7)	(2)	(116)	—	(116)
Improved recovery	1	—	—	—	—	1	—	1
Extensions, discoveries and other additions	122	—	—	—	—	122	—	122
Production	(62)	—	(7)	—	(5)	(74)	—	(74)
Sales of reserves in place	(6)	—	—	—	—	(6)	—	(6)
End of year - 2015	580	—	52	201	22	855	—	855
Proved developed reserves:								
Beginning of year - 2013	169	—	45	168	20	402	63	465
End of year - 2013	241	—	37	176	19	473	77	550
End of year - 2014	294	—	30	175	19	518	—	518
End of year - 2015	327	—	25	173	16	541	—	541
Proved undeveloped reserves:								
Beginning of year - 2013	218	—	27	41	4	290	19	309
End of year - 2013	256	—	27	39	6	328	14	342
End of year - 2014	340	—	27	33	10	410	—	410
End of year - 2015	253	—	27	28	6	314	—	314

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[a]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas liquids								
Proved developed and undeveloped reserves:								
Beginning of year - 2013	88	—	38	—	1	127	—	127
Revisions of previous estimates	13	—	—	—	—	13	—	13
Purchases of reserves in place	2	—	—	—	—	2	—	2
Extensions, discoveries and other additions	25	—	—	—	—	25	—	25
Production	(9)	—	(4)	—	—	(13)	—	(13)
End of year - 2013	119	—	34	—	1	154	—	154
Revisions of previous estimates	4	—	—	—	—	4	—	4
Improved recovery	1	—	—	—		1	—	1
Extensions, discoveries and other additions	48	—	—	—	—	48	—	48
Production	(11)	—	(4)	—	—	(15)	—	(15)
End of year - 2014	161	—	30	—	1	192	—	192
Revisions of previous estimates	(31)	—	2	—	(1)	(30)	—	(30)
Extensions, discoveries and other additions	57	—	—	—	—	57	—	57
Production	(14)	—	(4)	—	—	(18)	—	(18)
Sales of reserves in place	(1)	—	—	—	—	(1)	—	(1)
End of year - 2015	172	—	28	—	—	200	—	200
Proved developed reserves:								
Beginning of year - 2013	29	—	23	—	1	53	—	53
End of year - 2013	51	—	18	—	1	70	—	70
End of year - 2014	68	—	15	—	—	83	—	83
End of year - 2015	92	—	12	—	—	104	—	104
Proved undeveloped reserves:								
Beginning of year - 2013	59	—	15	—	—	74	—	74
End of year - 2013	68	—	16	—	—	84	—	84
End of year - 2014	93	—	15	—	1	109	—	109
End of year - 2015	80	—	16	—	—	96	—	96

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(bcf)	U.S.	Canada	E.G.[a]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas								
Proved developed and undeveloped reserves:								
Beginning of year - 2013	1,043	—	1,424	209	14	2,690	89	2,779
Revisions of previous estimates	(4)	—	45	4	23	68	20	88
Purchases of reserves in place	13	—	3	—	—	16	—	16
Extensions, discoveries and other additions	163	—	9	—	—	172	3	175
Production[b]	(114)	—	(161)	(8)	(9)	(292)	(19)	(311)
Sales of reserves in place	(76)	—	—	—	—	(76)	—	(76)
End of year - 2013	1,025	—	1,320	205	28	2,578	93	2,671
Revisions of previous estimates	(24)	—	1	5	2	(16)	7	(9)
Purchases of reserves in place	5	—	—	—	—	5	—	5
Extensions, discoveries and other additions	290	—	44	—	—	334	2	336
Production[b]	(113)	—	(160)	(1)	(8)	(282)	(13)	(295)
Sales of reserves in place	(39)	—	—	—	—	(39)	(89)	(128)
End of year - 2014	1,144	—	1,205	209	22	2,580	—	2,580
Revisions of previous estimates	(191)	—	35	(3)	1	(158)	—	(158)
Purchases of reserves in place	1	—	—	—	—	1	—	1
Extensions, discoveries and other additions	394	—	—	—	—	394	—	394
Production[b]	(128)	—	(150)	—	(8)	(286)	—	(286)
Sales of reserves in place	(69)	—	—	—	—	(69)	—	(69)
End of year - 2015	1,151	—	1,090	206	15	2,462	—	2,462
Proved developed reserves:								
Beginning of year - 2013	546	—	980	99	8	1,633	20	1,653
End of year - 2013	540	—	823	95	21	1,479	20	1,499
End of year - 2014	575	—	664	94	17	1,350	—	1,350
End of year - 2015	640	—	552	94	11	1,297	—	1,297
Proved undeveloped reserves:								
Beginning of year - 2013	497	—	444	110	6	1,057	69	1,126
End of year - 2013	485	—	497	110	7	1,099	73	1,172
End of year - 2014	569	—	541	115	5	1,230	—	1,230
End of year - 2015	511	—	538	112	4	1,165	—	1,165

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Synthetic crude oil								
Proved developed and undeveloped reserves:								
Beginning of year - 2013	—	653	—	—	—	653	—	653
Revisions of previous estimates	—	36	—	—	—	36	—	36
Extensions, discoveries and other additions	—	6	—	—	—	6	—	6
Production	—	(15)	—	—	—	(15)	—	(15)
End of year - 2013	—	680	—	—	—	680	—	680
Revisions of previous estimates	—	(55)	—	—	—	(55)	—	(55)
Purchases of reserves in place	—	38	—	—	—	38	—	38
Production	—	(15)	—	—	—	(15)	—	(15)
End of year - 2014	—	648	—	—	—	648	—	648
Revisions of previous estimates	—	67	—	—	—	67	—	67
Production	—	(17)	—	—	—	(17)	—	(17)
End of year - 2015	—	698	—	—	—	698	—	698
Proved developed reserves:								
Beginning of year - 2013	—	653	—	—	—	653	—	653
End of year - 2013	—	674	—	—	—	674	—	674
End of year - 2014	—	644	—	—	—	644	—	644
End of year - 2015	—	698	—	—	—	698	—	698
Proved undeveloped reserves:								
End of year - 2013	—	6	—	—	—	6	—	6
End of year - 2014	—	4	—	—	—	4	—	4

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	U.S.	Canada	E.G.[a]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Total Proved Reserves								
Proved developed and undeveloped reserves:								
Beginning of year - 2013	649	653	347	244	27	1,920	97	2,017
Revisions of previous estimates	45	36	7	12	11	111	21	132
Improved recovery	—	—	—	—	—	—	11	11
Purchases of reserves in place	16	—	1	—	—	17	—	17
Extensions, discoveries and other additions	164	6	2	3	—	175	9	184
Production[b]	(74)	(15)	(39)	(10)	(7)	(145)	(32)	(177)
Sales of reserves in place	(13)	—	—	—		(13)	—	(13)
End of year - 2013	787	680	318	249	31	2,065	106	2,171
Revisions of previous estimates	36	(55)	—	(3)	—	(22)	11	(11)
Improved recovery	2	—	—	—	—	2	—	2
Purchases of reserves in place	8	38	—	—	—	46	—	46
Extensions, discoveries and								—
other additions	250	—	8	—	7	265	3	268
Production[b]	(87)	(15)	(38)	(3)	(5)	(148)	(19)	(167)
Sales of reserves in place	(10)	—	—	—	—	(10)	(101)	(111)
End of year - 2014	986	648	288	243	33	2,198	—	2,198
Revisions of previous estimates	(173)	67	8	(8)	(2)	(108)	—	(108)
Improved recovery	1	—	—	—	—	1	—	1
Purchases of reserves in place	1	—	—	—	—	1	—	1
Extensions, discoveries and other additions	245	—	1	—	—	246	—	246
Production[b]	(98)	(17)	(36)	—	(6)	(157)	—	(157)
Sales of reserves in place	(18)	—	—	—	—	(18)	—	(18)
End of year - 2015	944	698	261	235	25	2,163	—	2,163
Proved developed reserves:								
Beginning of year - 2013	289	653	231	185	22	1,380	66	1,446
End of year - 2013	382	674	193	192	23	1,464	80	1,544
End of year - 2014	458	644	155	191	22	1,470	—	1,470
End of year - 2015	526	698	129	189	18	1,560	—	1,560
Proved undeveloped reserves:								
Beginning of year - 2013	360	—	116	59	5	540	31	571
End of year - 2013	405	6	125	57	8	601	26	627
End of year - 2014	528	4	133	52	11	728	—	728
End of year - 2015	418	—	132	46	7	603	—	603

[a] Consists of estimated reserves from properties governed by production sharing contracts.

[b] Excludes the resale of purchased natural gas used in reservoir management.

2015

Total proved reserves declined 35 mmboe, primarily due to negative revisions in the U.S. totaling 173 mmboe largely a result of reductions to our capital development program and adherence to the SEC 5-year rule as well as routine production. This decline was partially offset by increased reserves from the drilling programs in our U.S.

unconventional shale plays totaling 245 mmboe as well as a positive revision of 67 mmboe in OSM. The OSM revision was a consequence of technical reevaluation and lower royalty percentages from lower realized prices. Royalties paid in Canada are on a sliding scale; as the sales price of our synthetic crude oil increases, our royalty rate increases.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

2014

U.S. proved reserves increases in 2014 from extensions, discoveries and additions of 250 mmboe were the result of development activity in our U.S. resource plays. The sales of reserves in place related to our Norway and Angola discontinued operations were the largest decreases in 2014 proved reserves. The negative 55 mmboe revision to Canadian synthetic crude oil reserves primarily reflects the impact of technical and price changes on calculated royalty volumes as well as development plan changes in the mineable areas.

2013

U.S. proved reserves increases in 2013 from extensions, discoveries and additions of 164 mmboe and revisions of previous estimates of 45 mmboe were the result of drilling programs in our shale plays. Revisions of previous estimates increased 36 mmboe in Canada primarily due to price and cost changes.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	Year Ended December 31,					
(In millions)	U.S.	Canada	E.G.	Other Africa	Other Int'l	Total
2015 Capitalized Costs:						
Proved properties	$27,816	$9,538	$1,955	$828	$5,741	$45,878
Unproved properties	1,625	1,389	86	465	242	3,807
Total	29,441	10,927	2,041	1,293	5,983	49,685
Accumulated depreciation, depletion and amortization:						
Proved properties	13,656	1,420	1,105	263	5,195	21,639
Unproved properties [(a)]	675	310	—	107	114	1,206
Total	14,331	1,730	1,105	370	5,309	22,845
Net capitalized costs	$15,110	$9,197	$936	$923	$674	$26,840
2014 Capitalized Costs:						
Proved properties	$28,334	$9,481	$1,804	$823	$5,707	$46,149
Unproved properties	1,861	1,505	64	460	237	4,127
Total	30,195	10,986	1,868	1,283	5,944	50,276
Accumulated depreciation, depletion and amortization:						
Proved properties	13,746	1,183	1,010	260	5,075	21,274
Unproved properties	189	1	—	—	9	199
Total	13,935	1,184	1,010	260	5,084	21,473
Net capitalized costs	$16,260	$9,802	$858	$1,023	$860	$28,803

(a) Includes unproved property impairments (see Note 13).

Costs Incurred for Property Acquisition, Exploration and Development[(a)]

(In millions)	U.S.	Canada	E.G.	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
December 31, 2015								
Property acquisition:								
Proved	$4	$—	$—	$—	$—	$4	$—	$4
Unproved	61	—	—	1	—	62	—	62
Exploration	959	1	60	38	50	1,108	—	1,108
Development	1,477	—	150	13	31	(c) 1,671	—	1,671
Total	$2,501	$1	(b) $210	$52	$81	$2,845	$—	$2,845
December 31, 2014								
Property acquisition:								
Proved	$26	$—	$—	$—	$—	$26	$—	$26
Unproved	202	3	—	53	2	260	1	261
Exploration	1,140	4	35	119	119	1,417	6	1,423
Development	3,532	196	139	16	94	3,977	418	4,395
Total	$4,900	$203	$174	$188	$215	$5,680	$425	$6,105

December 31, 2013								
Property acquisition:								
Proved	$51	$30	$9	$—	$—	$90	$—	$90
Unproved	157	—	—	44	21	222	—	222
Exploration	885	9	4	124	151	1,173	98	1,271
Development	2,876	280	84	46	83	3,369	499	3,868
Total	$3,969	$319	$97	$214	$255	$4,854	$597	$5,451

(a) Includes costs incurred whether capitalized or expensed.

(b) Reflects reimbursements earned from the governments of Canada and Alberta related to funds previously expended for Quest CCS capital equipment.

(c) Includes negative revisions to asset retirement costs primarily due to lower estimated costs for future abandonments as well as changes in timing of these activities in the U.K.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

	U.S.	Canada	E.G.	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Year Ended December 31, 2015								
Revenues and other income:								
Sales	$3,374	$700	$40	$—	$329	$4,443	$—	$4,443
Transfers	—	—	296	—	—	296	—	296
Other income[a]	230	—	—	(109)	1	122	—	122
Total revenues and other income	3,604	700	336	(109)	330	4,861	—	4,861
Expenses:								
Production costs	(1,259)	(660)	(84)	(31)	(177)	(2,211)	—	(2,211)
Exploration expenses[b]	(750)	(348)	(41)	(36)	(143)	(1,318)	—	(1,318)
Depreciation, depletion and amortization[c]	(2,758)	(266)	(92)	(5)	(163)	(3,284)	—	(3,284)
Technical support and other	(47)	(2)	(6)	(2)	(3)	(60)	—	(60)
Total expenses	(4,814)	(1,276)	(223)	(74)	(486)	(6,873)	—	(6,873)
Results before income taxes	(1,210)	(576)	113	(183)	(156)	(2,012)	—	(2,012)
Income tax provision	437	31	(33)	87	86	608	—	608
Results of operations	$(773)	$(545)	$80	$(96)	$(70)	$(1,404)	$—	$(1,404)
Year Ended December 31, 2014								
Revenues and other income:								
Sales	$5,754	$1,316	$43	$244	$440	$7,797	$189	$7,986
Transfers	3	—	588	—	3	594	1,848	2,442
Other income[a]	(85)	—	—	—	—	(85)	1,832	1,747
Total revenues and other income	5,672	1,316	631	244	443	8,306	3,869	12,175
Expenses:								
Production costs	(1,544)	(803)	(154)	(79)	(253)	(2,833)	(181)	(3,014)
Exploration expenses	(607)	(1)	(26)	(103)	(56)	(793)	(5)	(798)
Depreciation, depletion and amortization[c]	(2,474)	(206)	(93)	(9)	(115)	(2,897)	(105)	(3,002)
Technical support and other	(193)	(15)	(31)	(21)	(14)	(274)	(7)	(281)
Total expenses	(4,818)	(1,025)	(304)	(212)	(438)	(6,797)	(298)	(7,095)
Results before income taxes	854	291	327	32	5	1,509	3,571	5,080
Income tax provision	(302)	(71)	(117)	(32)	(18)	(540)	(1,496)	(2,036)
Results of operations	$552	$220	$210	$—	$(13)	$969	$2,075	$3,044
Year Ended December 31, 2013								
Revenues and other income:								
Sales	$5,059	$1,376	$33	$1,106	$687	$8,261	$599	$8,860
Transfers	3	—	715	—	6	724	2,935	3,659
Other income[a]	(9)	—	—	—	(8)	(17)	—	(17)
Total revenues and other income	5,053	1,376	748	1,106	685	8,968	3,534	12,502
Expenses:								
Production costs	(1,318)	(867)	(113)	(73)	(271)	(2,642)	(273)	(2,915)
Exploration expenses	(717)	(8)	(3)	(65)	(98)	(891)	(107)	(998)
Depreciation, depletion and amortization[c]	(1,980)	(218)	(97)	(28)	(151)	(2,474)	(345)	— (2,819)

Technical support and other	(185)	(21)	(30)	(19)	(15)	(270)	(38)	(308)
Total expenses	(4,200)	(1,114)	(243)	(185)	(535)	(6,277)	(763)	(7,040)
Results before income taxes	853	262	505	921	150	2,691	2,771	5,462
Income tax provision	(323)	(66)	(182)	(920)	(117)	(1,608)	(1,948)	(3,556)
Results of operations	$530	$196	$323	$1	$33	$1,083	$823	$1,906

(a) Includes net gain (loss) on dispositions (see Note 5).
(b) Includes unproved property impairments (see Note 13).
(c) Includes long-lived asset impairments (see Note 13).
(d) Includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase (see Note 9).

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of operations for oil and gas producing activities to segment income:

	Year Ended December 31,		
(In millions)	2015	2014	2013
Results of operations	$(1,404)	$3,044	$1,906
Discontinued operations	—	(2,075)	(823)
Results of continuing operations	(1,404)	969	1,083
Items not included in results of oil and gas operations, net of tax:			
Marketing income and other non-oil and gas producing related activities	(75)	73	40
Income from equity method investments	127	327	340
Items not allocated to segment income, net of tax:			
Loss (gain) on asset dispositions	(57)	58	20
Long-lived asset impairments	819	69	10
Unrealized gain on derivatives	(32)	—	—
Alberta provincial corporate tax rate increase	135	—	—
Segment income	$(487)	$1,496	$1,493

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves
U.S. GAAP prescribes guidelines for computing the standardized measure of future net cash flows and changes therein relating to estimated proved reserves, giving very specific assumptions to be made such as the use of a 10% discount rate and an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month. These and other required assumptions have not always proved accurate in the past, and other valid assumptions would give rise to substantially different results. This information is not the fair value nor does it represent the expected present value of future cash flows of our crude oil and condensate, natural gas liquid, natural gas and synthetic crude oil reserves.

(In millions)	U.S.	Canada	E.G.	Other Africa	Other Int'l	Total
Year Ended December 31, 2015						
Future cash inflows	$31,026	$31,087	$2,671	$12,157	$1,281	$78,222
Future production and support costs	(12,270)	(27,459)	(1,095)	(901)	(902)	(42,627)
Future development costs	(6,637)	(2,929)	(94)	(689)	(1,537)	(11,886)
Future income tax expenses	(778)	—	(369)	(9,857)	602	(10,402)
Future net cash flows	$11,341	$699	$1,113	$710	$(556)[a]	$13,307
10% annual discount for timing of cash flows	(6,082)	(534)	(380)	(441)	352	(7,085)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$5,259	$165	$733	$269	$(204)	$6,222
-related to discontinued operations	$—	$—	$—	$—	—	—
Year Ended December 31, 2014						
Future cash inflows	$66,307	$55,675	$5,027	$23,803	$3,040	$153,852
Future production and support costs	(19,504)	(34,838)	(1,270)	(803)	(1,452)	(57,867)
Future development costs	(14,626)	(9,754)	(259)	(680)	(1,669)	(26,988)
Future income tax expenses	(8,124)	(2,190)	(922)	(21,008)	(9)	(32,253)
Future net cash flows	$24,053	$8,893	$2,576	$1,312	$(90)	$36,744
10% annual discount for timing of cash flows	(12,138)	(6,613)	(915)	(742)	221	(20,187)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$11,915	$2,280	$1,661	$570	$131	$16,557
-related to discontinued operations	$—	$—	$—	$—	$—	$—
Year Ended December 31, 2013						
Future cash inflows	$54,099	$59,585	$5,911	$28,195	$3,178	$150,968
Future production and support costs	(16,774)	(35,954)	(1,619)	(976)	(1,191)	(56,514)
Future development costs	(9,685)	(9,694)	(367)	(793)	(1,302)	(21,841)
Future income tax expenses	(7,592)	(3,098)	(1,032)	(24,982)	(643)	(37,347)
Future net cash flows	$20,048	$10,839	$2,893	$1,444	$42	$35,266
10% annual discount for timing of cash flows	(9,940)	(8,300)	(1,084)	(828)	128	(20,024)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$10,108	$2,539	$1,809	$616	$170	$15,242
-related to discontinued operations	$—	$—	$—	$1,302	$1,228	$2,530

[a] Future cash flows for Other International reflects the impact of future abandonment costs related to the U.K.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Changes in the Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
(In millions)	2015	2014	2013
Sales and transfers of oil and gas produced, net of production and support costs	$(2,460)	$(5,284)	$(6,080)
Net changes in prices and production and support costs related to future production	(25,239) [b]	(2,688)	(336)
Extensions, discoveries and improved recovery, less related costs	1,100	3,539	3,415
Development costs incurred during the period	1,694	4,088	3,429
Changes in estimated future development costs	9,397	(1,423)	898
Revisions of previous quantity estimates[a]	(7,625)	(3,193)	1,330
Net changes in purchases and sales of minerals in place	(460)	(168)	(229)
Accretion of discount	2,967	3,132	2,657
Net change in income taxes	10,291	3,312	(1,930)
Net change for the year	(10,335)	1,315	3,154
Beginning of the year related to continuing operations	16,557	15,242	12,088
End of the year related to continuing operations	$6,222	$16,557	$15,242
Net change for the year related to discontinued operations	$—	$(2,530)	$399

(a) Includes amounts resulting from changes in the timing of production.

(b) Decrease primarily due to lower realized prices.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as of December 31, 2015.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management’s Report on Internal Control over Financial Reporting" under Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

See "Report of Independent Registered Public Accounting Firm" under Item 8 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2015, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item is incorporated by reference to "Proposal 1: Election of Directors," "Corporate Governance—Committees of the Board" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2016 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2015 (the "2016 Proxy Statement").

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for information about our executive officers.

Our Code of Business Conduct and the Code of Ethics for Senior Financial Officers are available on our website at www.marathonoil.com.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the 2016 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Portions of information required by this item are incorporated by reference to "Security Ownership of Certain Beneficial Owners and Management" in the 2016 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2015 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan")
- Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") – No additional awards will be granted under this plan.
- Marathon Oil Corporation 2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.
- Deferred Compensation Plan for Non-Employee Directors – No additional awards will be granted under this plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights[c]	Number of securities remaining available for future issuance under equity compensation plans	
Equity compensation plans approved by stockholders	13,715,861	(a)	$29.97	30,434,538	(d)
Equity compensation plans not approved by stockholders	12,291	(b)	N/A	—	
Total	13,728,152		N/A	30,434,538	

(a) Includes the following:

- 3,513,104 stock options outstanding under the 2012 Plan; 8,479,140 stock options outstanding under the 2007 Plan; 673,175 stock options outstanding under the 2003 Plan;
- 294,800 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2012 Plan, 2007 Plan and 2003 Plan; common stock units credited under the 2012 Plan, 2007 Plan and 2003 Plan were 97,292, 163,513 and 33,995, respectively;
- 755,642 restricted stock units granted to non-officers under the 2012 Plan and 2007 Plan and outstanding as of December 31, 2015.

In addition to the awards reported above 3,261,702 shares of restricted stock were issued and outstanding as of December 31, 2015, but subject to forfeiture restrictions under the 2012 Plan.

(b)

Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon Oil common stock in place of the common stock units.

(c) The weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(d) Reflects the shares available for issuance under the 2012 Plan. No more than 14,592,300 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, canceled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to "Transactions with Related Persons," and "Proposal 1: Election of Directors—Director Independence" in the 2016 Proxy Statement.

Item 14. Principal Accountant Fees and Services

Information required by this item is incorporated by reference to "Proposal 2: Ratification of Independent Auditor for 2016" in the 2016 Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements – See Part II, Item 8. of this Annual Report on Form 10-K.

2. Financial Statement Schedules – Financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Exhibits – The information required by this Item 15 is incorporated by reference to the Exhibit Index accompanying this Annual Report on Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 25, 2016	MARATHON OIL CORPORATION
	By: /s/ GARY E. WILSON
	Gary E. Wilson
	Vice President, Controller and Chief Accounting Officer

POWER OF ATTORNEY

Each person whose signature appears below appoints Lee M. Tillman, John R. Sult, and Gary E. Wilson, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, with full power and authority to each of said attorneys-in-fact and agents to do and perform each and every act whatsoever that is necessary, appropriate or advisable in connection with any or all of the above-described matters and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 25, 2016 on behalf of the registrant and in the capacities indicated.

Signature	Title
/S/ LEE M. TILLMAN Lee M. Tillman	President and Chief Executive Officer and Director
/S/ JOHN R. SULT John R. Sult	Executive Vice President and Chief Financial Officer
/s/ GARY E. WILSON Gary E. Wilson	Vice President, Controller and Chief Accounting Officer
/S/ DENNIS H. REILLEY Dennis H. Reilley	Chairman of the Board
/s/ GAURDIE E. BANISTER, JR. Gaurdie E. Banister, Jr.	Director
/S/ GREGORY H. BOYCE Gregory H. Boyce	Director
/S/ PIERRE BRONDEAU Pierre Brondeau	Director
/S/ CHADWICK C. DEATON Chadwick C. Deaton	Director
/S/ MARCELA E. DONADIO Marcela E. Donadio	Director

/S/ PHILIP LADER Philip Lader	Director
/S/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director

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Exhibit Index

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form	Exhibit	Filing Date
3	Articles of Incorporation and By-laws			
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	10-Q	3.1	8/8/2013
3.2	Marathon Oil Corporation By-laws (Amended and restated as of September 1, 2015)	8-K	3.1	8/28/2015
3.3	Specimen of Common Stock Certificate	10-K	3.3	2/28/2014
4	Instruments Defining the Rights of Security Holders, Including Indentures			
4.1	Indenture, dated as of February 26, 2002, between Marathon Oil Corporation and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon Oil Corporation. Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request	10-K	4.2	2/28/2014
10	Material Contracts			
10.1	Amended and Restated Credit Agreement, dated as of May 28, 2014, among Marathon Oil Corporation, as borrower, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	8-K	4.1	6/2/2014
10.2	First Amendment, dated as of May 5, 2015, to the Amended and Restated Credit Agreement dated as of May 28, 2014, by and among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	10-Q	10.1	5/7/2015
10.3†	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012
10.4†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement	8-K	10.1	8/1/2014
10.5†	Form of Performance Unit Award Agreement 2014 - 2016 Performance Cycle for Section 16 Officers	10-Q	10.1	5/7/2014
10.6†	Form of Performance Unit Award Agreement 2014 - 2016 Performance Cycle for Officers	10-Q	10.2	5/7/2014
10.7†	Form of Initial CEO Option Grant Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.1	11/6/2013

10.8†	Form of CEO Restricted Stock Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-Q	10.2	11/6/2013
10.9†	Form of CEO Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-Q	10.3	11/6/2013
10.10†	Form of Performance Unit Award Agreement (2013-2015 Performance Cycle) for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.1	5/10/2013

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Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form	Exhibit	Filing Date
10.11†	Form of Performance Unit Award Agreement (2013-2015 Performance Cycle) for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.2	5/10/2013
10.12†	Form of Nonqualified Stock Option Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.5	2/22/2013
10.13†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.6	2/22/2013
10.14†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-K	10.7	2/22/2013
10.15†	Form of Restricted Stock Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-K	10.8	2/22/2013
10.16†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.9	2/22/2013
10.17†	Form of Restricted Stock Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.10	2/22/2013
10.18†	Form of Nonqualified Stock Option Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.11	2/22/2013
10.19†	Form of Nonqualified Stock Option Award Agreement for non-officers in Canada granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.12	2/22/2013
10.20†	Form of Restricted Stock Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.13	2/22/2013
10.21†	Form of Restricted Stock Unit Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.14	2/22/2013
10.22†	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012
10.23†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.6	2/29/2012
10.24†		10-K	10.5	2/28/2011

	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan			
10.25†	Form of Nonqualified Stock Option Award Agreement granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.26	2/26/2010
10.26†	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003	10-K	10.9	2/26/2010

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form	Exhibit	Filing Date
10.27†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.22	2/26/2010
10.28†	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of January 1, 2012)	10-Q	10.3	5/7/2014
10.29†	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012
10.30†	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012
10.31†	Marathon Oil Corporation 2011 Officer Change in Control Severance Benefits Plan (as amended, effective November 1, 2014)	10-K	10.36	3/2/2015
10.32†	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011
10.33†	Marathon Oil Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009
10.34†	Marathon Oil Corporation Bonus Agreement Upon Commencement of Employment for Lee M. Tillman	10-Q	10.4	11/6/2013
10.35	Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC	8-K	10.1	5/26/2011
12.1*	Computation of Ratio of Earnings to Fixed Charges			
21.1*	List of Significant Subsidiaries			
23.1*	Consent of Independent Registered Public Accounting Firm			
23.2*	Consent of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists			
23.3*	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists			
23.4*	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists			
31.1*	Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
31.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
32.1*	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350			
32.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350			
99.1*	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2015			
99.2	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2014	10-K	99.1	3/2/2015

99.3	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2013	10-K	99.1	2/28/2014

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Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form	Exhibit	Filing Date
99.4*	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2014			
99.5	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2013	10-K	99.4	3/2/2015
99.6	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2012	10-K	99.4	2/28/2014
99.7*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2014			
99.8	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2013	10-K	99.7	3/2/2015
99.9	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2012	10-K	99.7	2/28/2014
101.INS*	XBRL Instance Document			
101.SCH*	XBRL Taxonomy Extension Schema			
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase			
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase			
101.LAB*	XBRL Taxonomy Extension Label Linkbase			
101.DEF*	XBRL Taxonomy Extension Definition Linkbase			
*	Filed herewith.			
**	Furnished, not filed.			
†	Management contract or compensatory plan or arrangement.			