MARATHON OIL CORP
Form 10-Q
November 03, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

| | |
|---|---|
| [X] | QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934<br>For the Quarterly Period Ended September 30, 2016 |

OR

| | |
|---|---|
| [ ] | TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934<br>For the transition period from _____ to _____ |

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)

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 (or for such shorter period that the registrant was required to file such reports), 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | | | | |
|---|---|---|---|---|
| Large accelerated filer | þ | | Accelerated filer | o |
| Non-accelerated filer | o | (Do not check if a smaller reporting company) | Smaller reporting company | o |

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

There were 847,211,288 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2016.

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to “Marathon Oil,” “we,” “our,” or “us” in this Form 10-Q 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).
For certain industry specific terms used in this Form 10-Q, please see "Definitions" in our 2015 Annual Report on Form 10-K.

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Part I - Financial Information
Item 1. Financial Statements

MARATHON OIL CORPORATION
Consolidated Statements of Income (Unaudited)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In millions, except per share data) | 2016 | 2015 | 2016 | 2015 |
| Revenues and other income: | | | | |
| Sales and other operating revenues, including related party | $1,020 | $1,300 | $2,604 | $3,887 |
| Marketing revenues | 80 | 84 | 227 | 471 |
| Income from equity method investments | 59 | 36 | 110 | 98 |
| Net gain (loss) on disposal of assets | 47 | (109) | 281 | (108) |
| Other income | 23 | 12 | 39 | 38 |
| Total revenues and other income | 1,229 | 1,323 | 3,261 | 4,386 |
| Costs and expenses: | | | | |
| Production | 295 | 406 | 973 | 1,300 |
| Marketing, including purchases from related parties | 80 | 84 | 226 | 471 |
| Other operating | 189 | 93 | 393 | 281 |
| Exploration | 83 | 585 | 296 | 786 |
| Depreciation, depletion and amortization | 594 | 717 | 1,764 | 2,289 |
| Impairments | 47 | 337 | 48 | 381 |
| Taxes other than income | 39 | 46 | 126 | 191 |
| General and administrative | 105 | 125 | 388 | 464 |
| Total costs and expenses | 1,432 | 2,393 | 4,214 | 6,163 |
| Income (loss) from operations | (203) | (1,070) | (953) | (1,777) |
| Net interest and other | (87) | (75) | (258) | (180) |
| Income (loss) before income taxes | (290) | (1,145) | (1,211) | (1,957) |
| Provision (benefit) for income taxes | (98) | (396) | (442) | (546) |
| Net income (loss) | $(192) | $(749) | $(769) | $(1,411) |
| Net income (loss) per share: | | | | |
| Basic | $(0.23) | $(1.11) | $(0.95) | $(2.09) |
| Diluted | $(0.23) | $(1.11) | $(0.95) | $(2.09) |
| Dividends per share | $0.05 | $0.21 | $0.15 | $0.63 |
| Weighted average common shares outstanding: | | | | |
| Basic | 847 | 677 | 809 | 677 |
| Diluted | 847 | 677 | 809 | 677 |

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Net income (loss) | $(192) | $(749) | $(769) | $(1,411) |
| Other comprehensive income (loss) | | | | |
| Postretirement and postemployment plans | | | | |
| Change in actuarial loss and other | — | (2) | (5) | 160 |
| Income tax provision (benefit) | — | (1) | 2 | (58) |
| Postretirement and postemployment plans, net of tax | — | (3) | (3) | 102 |
| Other, net of tax | 3 | — | 1 | — |
| Other comprehensive income (loss) | 3 | (3) | (2) | 102 |
| Comprehensive income (loss) | $(189) | $(752) | $(771) | $(1,309) |

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

| (In millions, except per share data) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,953 | $ 1,221 |
| Receivables, less reserve of $4 and $4 | 783 | 912 |
| Inventories | 221 | 313 |
| Other current assets | 85 | 144 |
| Total current assets | 3,042 | 2,590 |
| Equity method investments | 931 | 1,003 |
| Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,775 and $23,260 | 25,976 | 27,061 |
| Goodwill | 115 | 115 |
| Other noncurrent assets | 2,246 | 1,542 |
| Total assets | $ 32,310 | $ 32,311 |
| Liabilities | | |
| Current liabilities: | | |
| Accounts payable | $ 964 | $ 1,313 |
| Payroll and benefits payable | 121 | 133 |
| Accrued taxes | 66 | 132 |
| Other current liabilities | 256 | 150 |
| Long-term debt due within one year | 1 | 1 |
| Total current liabilities | 1,408 | 1,729 |
| Long-term debt | 7,277 | 7,276 |
| Deferred tax liabilities | 2,399 | 2,441 |
| Defined benefit postretirement plan obligations | 400 | 403 |
| Asset retirement obligations | 1,607 | 1,601 |
| Deferred credits and other liabilities | 297 | 308 |
| Total liabilities | 13,388 | 13,758 |
| Commitments and contingencies | | |
| Stockholders’ Equity | | |
| Preferred stock – no shares issued or outstanding (no par value, 26 million shares authorized) | — | — |
| Common stock: | | |
| Issued – 937 million shares and 770 million shares (par value $1 per share, 1.1 billion shares authorized) | 937 | 770 |
| Securities exchangeable into common stock – no shares issued or outstanding (no par value, 29 million shares authorized) | — | — |
| Held in treasury, at cost – 90 million and 93 million shares | (3,406 ) | (3,554 ) |
| Additional paid-in capital | 7,442 | 6,498 |
| Retained earnings | 14,086 | 14,974 |
| Accumulated other comprehensive loss | (137 ) | (135 ) |
| Total stockholders' equity | 18,922 | 18,553 |
| Total liabilities and stockholders' equity | $ 32,310 | $ 32,311 |

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

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MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

| (In millions) | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|
| Increase (decrease) in cash and cash equivalents | | |
| Operating activities: | | |
| Net income (loss) | $(769) | $(1,411) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 1,764 | 2,289 |
| Impairments | 48 | 381 |
| Exploratory dry well costs and unproved property impairments | 203 | 708 |
| Net (gain) loss on disposal of assets | (281) | 108 |
| Deferred income taxes | (504) | (590) |
| Net (gain) loss on derivative instruments | 48 | (88) |
| Net cash received (paid) in settlement of derivative instruments | 51 | 18 |
| Pension and other postretirement benefits, net | 2 | 9 |
| Stock based compensation | 37 | 34 |
| Equity method investments, net | 26 | 41 |
| Changes in: | | |
| Current receivables | 140 | 738 |
| Inventories | 81 | 30 |
| Current accounts payable and accrued liabilities | (236) | (954) |
| All other operating, net | 8 | (100) |
| Net cash provided by operating activities | 618 | 1,213 |
| Investing activities: | | |
| Additions to property, plant and equipment | (983) | (2,948) |
| Acquisitions, net of cash acquired | (902) | — |
| Disposal of assets | 837 | 105 |
| Equity method investments - return of capital | 47 | 61 |
| Purchases of short-term investments | — | (925) |
| Maturities of short-term investments | — | 225 |
| All other investing, net | 2 | 22 |
| Net cash used in investing activities | (999) | (3,460) |
| Financing activities: | | |
| Borrowings | — | 1,996 |
| Debt issuance costs | — | (19) |
| Debt repayments | (1) | (34) |
| Common stock issuance | 1,236 | — |
| Dividends paid | (119) | (427) |
| All other financing, net | — | 14 |
| Net cash provided by financing activities | 1,116 | 1,530 |
| Effect of exchange rate on cash and cash equivalents | (3) | (1) |
| Net increase (decrease) in cash and cash equivalents | 732 | (718) |
| Cash and cash equivalents at beginning of period | 1,221 | 2,398 |
| Cash and cash equivalents at end of period | $1,953 | $1,680 |

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

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, in the opinion of management, these statements reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been prepared in accordance with the applicable rules of the SEC and do not include all of the information and disclosures required by U.S. GAAP for complete financial statements.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in our 2015 Annual Report on Form 10-K. The results of operations for the third quarter and first nine months of 2016 are not necessarily indicative of the results to be expected for the full year.

A reclassification between operating cash flow categories was made to the prior year's financial information to present it on a basis comparable with the current year's presentation with no impact on net cash provided by operating activities.

2. Accounting Standards

Not Yet Adopted

In August 2016, the FASB issued a new accounting standards update which seeks to reduce the existing diversity in practice in how certain transactions are classified in the statement of cash flows. This standard is effective for us in the first quarter of 2018 and shall be applied on a retrospective basis. 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 statements of cash flows and related disclosures.

In June 2016, the FASB issued a new accounting standards update that changes the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standard requires the use of a forward-looking "expected loss" model as opposed to the current "incurred loss" model. This standard is effective for us in the first quarter of 2020 and will be adopted on a modified retrospective basis through a cumulative-effect adjustment to retained earnings as of the beginning of the adoption period. Early adoption is permitted starting January 2019. 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.

In March 2016, the FASB issued a new accounting standards update that changes several aspects of accounting for share-based payment transactions, including a requirement to recognize all excess tax benefits and tax deficiencies as income tax expense or benefit in the income statement, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This standard is effective for us in the first quarter of 2017 and varying transition methods (modified retrospective, retrospective or prospective) should be applied to different provisions of the standard. Early adoption is permitted. We continue to evaluate the provisions of this accounting standards update but do not believe it will have a material effect on our consolidated results of operations, financial position or cash flows.

In February 2016, the FASB issued a new lease accounting standard, which requires lessees to recognize most leases, including operating leases, on the balance sheet as a right of use asset and lease liability. Short-term leases can continue being accounted for off balance sheet based on a policy election. This standard is effective for us in the first quarter of 2019 and should be applied using a modified retrospective approach at the beginning of the earliest period presented in the financial statements. Early adoption is permitted. We are evaluating the provisions of this accounting standards update and assessing the impact it will have on our consolidated results of operations, financial position or cash flows.

In January 2016, the FASB issued an accounting standards update that addresses certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. This standard is effective for us in the first quarter of 2018. Early adoption is allowed for certain provisions. 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 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 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 for the annual period ending after December 15, 2016 and for annual periods and interim periods thereafter.

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, 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. While early adoption is permitted, we do not plan to early adopt. 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. We continue to evaluate whether to use the full retrospective or the modified retrospective transition method. We also continue to assess the impact it will have on our consolidated results of operations, financial position or cash flows.

Recently Adopted

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 was applied on a retrospective basis. This standard only modifies disclosure requirements; as such, there was 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 whether 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 in the first quarter of 2016. The adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

3. Variable Interest Entity

The owners of the Athabasca Oil Sands Project, 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, Alberta, Canada. Costs under this contract are accrued and recorded on a monthly basis, with current liabilities of $2 million recorded at September 30, 2016 and December 31, 2015. 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 $483 million as of September 30, 2016. 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

4. 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, provided the effect is not antidilutive. The per share calculations below exclude 13 million stock options for the three and nine month periods ended September 30, 2016 and 13 million stock options for the three and nine month periods ended September 30, 2015 that were antidilutive.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In millions, except per share data) | 2016 | 2015 | 2016 | 2015 |
| Net income (loss) | $(192 ) | $(749 ) | $(769 ) | $(1,411) |
| Weighted average common shares outstanding | 847 | 677 | 809 | 677 |
| Weighted average common shares, diluted | 847 | 677 | 809 | 677 |
| Net income (loss) per share: | | | | |
| Basic | $(0.23) | $(1.11) | $(0.95) | $(2.09 ) |
| Diluted | $(0.23) | $(1.11) | $(0.95) | $(2.09 ) |

5. Acquisitions

On August 1, 2016, we closed on our acquisition of PayRock Energy Holdings, LLC ("PayRock"), a portfolio company of EnCap Investments, including approximately 61,000 net surface acres in the oil window of the Anadarko Basin STACK play in Oklahoma. The purchase price of $904 million, subject to closing adjustments was paid with cash on hand. We accounted for this transaction as an asset acquisition, with a majority of the purchase price allocated to property, plant and equipment. Although the purchase price allocation has not been finalized, we do not expect to record any material adjustments to the preliminary purchase price allocation. The pro forma incremental impact on our results of operations for each of the three and nine months ended September 30, 2016 and 2015 is not material.

6. Dispositions

2016 - North America E&P Segment

In September 2016, we entered into an agreement to sell certain non-operated $CO_2$ and waterflood assets in West Texas and New Mexico. The sale closed in late October for proceeds of $235 million, before closing adjustments. These assets are classified as held for sale in the consolidated balance sheet as of September 30, 2016 with total assets of $171 million and total liabilities of $4 million. During the quarter, we sold certain non-operated assets primarily in West Texas and New Mexico to multiple purchasers for combined proceeds of approximately $67 million, subject to certain adjustments, and recognized a total pre-tax gain of $55 million.

During the second quarter 2016, we announced the sale of our Wyoming upstream and midstream assets for proceeds of $870 million, before closing adjustments, of which approximately $690 million was received in the second quarter. A pre-tax gain of $266 million was recognized in the second quarter 2016. The remaining asset sales are subject to the receipt of certain tribal consents and are expected to close before year-end. These assets are classified as held for sale in the consolidated balance sheet as of September 30, 2016 with total assets of $105 million and total liabilities of $5 million. The proceeds for the remaining asset sales were deposited into an escrow account by the buyer.

In March and April 2016, we entered into separate agreements to sell our 10% working interest in the outside-operated Shenandoah discovery in the Gulf of Mexico, operated natural gas assets in the Piceance basin in Colorado and certain undeveloped acreage in West Texas for a combined total of approximately $80 million in proceeds, before closing adjustments. We closed on certain of the asset sales and recognized a net pre-tax loss on sale of $48 million for the nine months ended September 30, 2016, with the remaining asset sales expected to close by year-end.

2015 - North America E&P Segment

In the third quarter of 2015, we closed on 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 as a result of the anticipated sale (see Note 14).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

2015 - International E&P Segment

In the third quarter of 2015, we entered into an agreement 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. This transaction closed during the first quarter of 2016.

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.

- N.A. E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- 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 (loss) represents income (loss) which excludes 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. Additionally, items which affect comparability such as: gains or losses on dispositions, certain impairments, change in tax expense associated with a tax rate change, unrealized gains or losses on commodity derivative instruments, pension settlement losses or other items (as determined by the CODM) are not allocated to operating segments.

| | Three Months Ended September 30, 2016 | | | | | |
|---|---|---|---|---|---|---|
| (In millions) | N.A. E&P | Int'l E&P | OSM | Not Allocated to Segments | | Total |
| Sales and other operating revenues | $604 | $152 | $239 | $ 25 | (c) | $1,020 |
| Marketing revenues | 44 | 36 | — | — | | 80 |
| Total revenues | 648 | 188 | 239 | 25 | | 1,100 |
| Income from equity method investments | — | 59 | — | — | | 59 |
| Net gain on disposal of assets and other income | 19 | 7 | — | 44 | (d) | 70 |
| Less: | | | | | | |
| Production expenses | 113 | 47 | 135 | — | | 295 |
| Marketing costs | 45 | 35 | — | — | | 80 |
| Exploration expenses | 35 | 10 | — | 38 | | 83 |
| Depreciation, depletion and amortization | 443 | 66 | 72 | 13 | | 594 |
| Impairments | — | — | — | 47 | (e) | 47 |
| Other expenses [a] | 85 | 18 | 9 | 182 | (f) | 294 |
| Taxes other than income | 35 | — | 4 | — | | 39 |
| Net interest and other | — | — | — | 87 | | 87 |
| Income tax provision (benefit) | (30 ) | 19 | 4 | (91 ) | | (98 ) |
| Segment income (loss) / Net income (loss) | $(59 ) | $59 | $15 | $ (207 ) | | $(192 ) |
| Capital expenditures [b] | $216 | $18 | $12 | $ 3 | | $249 |

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized gain on commodity derivative instruments.

(d) Primarily related to certain non-operated assets in West Texas and New Mexico. (see Note 6).

(e) Proved property impairments (see Note 14).

(f) Includes termination payment on our Gulf of Mexico deepwater drilling rig contract of $113 million and pension settlement loss of $14 million (see Note 8).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

| (In millions) | Three Months Ended September 30, 2015 N.A. E&P | Int'l E&P | OSM | Not Allocated to Segments | | Total |
|---|---|---|---|---|---|---|
| Sales and other operating revenues | $796 | $182 | $242 | $ 80 | (c) | $1,300 |
| Marketing revenues | 57 | 25 | 2 | — | | 84 |
| Total revenues | 853 | 207 | 244 | 80 | | 1,384 |
| Income (loss) from equity method investments | — | 48 | — | (12) | (d) | 36 |
| Net gain (loss) on disposal of assets and other income | 6 | 6 | — | (109) | (e) | (97) |
| Less: | | | | | | |
| Production expenses | 179 | 61 | 166 | — | | 406 |
| Marketing costs | 56 | 25 | 3 | — | | 84 |
| Exploration expenses | 22 | 10 | — | 553 | (f) | 585 |
| Depreciation, depletion and amortization | 549 | 79 | 76 | 13 | | 717 |
| Impairments | — | — | 4 | 333 | (g) | 337 |
| Other expenses [a] | 106 | 25 | 8 | 79 | (h) | 218 |
| Taxes other than income | 42 | — | 5 | (1) | | 46 |
| Net interest and other | — | — | — | 75 | | 75 |
| Income tax provision (benefit) | (34) | 32 | (7) | (387) | | (396) |
| Segment income (loss) / Net income (loss) | $(61) | $29 | $(11) | $ (706) | | $(749) |
| Capital expenditures [b] | $564 | $30 | $(11) | $ 12 | | $595 |

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Unrealized gain on commodity derivative instruments.
(d) Partial impairment of investment in equity method investee (see Note 14).
(e) Includes loss on sale of East Africa exploration acreage (see Note 6.).
(f) Unproved property impairments associated with lower forecasted commodity prices and change in conventional exploration strategy (see Note 13).
(g) Proved property impairments (see Note 14).
(h) Includes pension settlement loss of $18 million (see Note 8) and severance related expenses associated with workforce reductions of $4 million.

| (In millions) | Nine Months Ended September 30, 2016 N.A. E&P | Int'l E&P | OSM | Not Allocated to Segments | | Total |
|---|---|---|---|---|---|---|
| Sales and other operating revenues | $1,714 | $407 | $572 | $ (89) | (c) | $2,604 |
| Marketing revenues | 128 | 74 | 25 | — | | 227 |
| Total revenues | 1,842 | 481 | 597 | (89) | | 2,831 |
| Income from equity method investments | — | 110 | — | — | | 110 |
| Net gain on disposal of assets and other income | 22 | 20 | 1 | 277 | (d) | 320 |
| Less: | | | | | | |
| Production expenses | 376 | 156 | 441 | — | | 973 |
| Marketing costs | 129 | 72 | 25 | — | | 226 |
| Exploration expenses | 90 | 20 | 7 | 179 | (e) | 296 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Depreciation, depletion and amortization | 1,363 | 184 | 181 | 36 | | 1,764 |
| Impairments | 1 | — | — | 47 | (f) | 48 |
| Other expenses [a] | 300 | 56 | 25 | 400 | (g) | 781 |
| Taxes other than income | 112 | — | 13 | 1 | | 126 |
| Net interest and other | — | — | — | 258 | | 258 |
| Income tax provision (benefit) | (183 ) | 5 | (23 ) | (241 ) | | (442 ) |
| Segment income (loss) / Net income (loss) | $(324 ) | $118 | $(71 ) | $ (492 ) | | $(769 ) |
| Capital expenditures [b] | $684 | $62 | $28 | $ 11 | | $785 |

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Unrealized loss on commodity derivative instruments.
(d) Primarily related to net gain on disposal of assets (see Note 6).
(e) Primarily associated with impairments associated with decision to not drill remaining Gulf of Mexico undeveloped leases (see Note 13).
(f) Proved property impairments (see Note 14).
(g) Includes termination payment on our Gulf of Mexico deepwater drilling rig contract of $113 million and includes pension settlement loss of $93 million and severance related expenses associated with workforce reductions of $8 million (see Note 8).

| (In millions) | Nine Months Ended September 30, 2015 N.A. E&P | Int'l E&P | OSM | Not Allocated to Segments | | Total |
|---|---|---|---|---|---|---|
| Sales and other operating revenues | $2,639 | $575 | $614 | $59 | (c) | $3,887 |
| Marketing revenues | 345 | 81 | 45 | — | | 471 |
| Total revenues | 2,984 | 656 | 659 | 59 | | 4,358 |
| Income (loss) from equity method investments | — | 110 | — | (12) | (d) | 98 |
| Net gain (loss) on disposal of assets and other income | 17 | 20 | 1 | (108) | (e) | (70) |
| Less: | | | | | | |
| Production expenses | 560 | 192 | 548 | — | | 1,300 |
| Marketing costs | 348 | 79 | 44 | — | | 471 |
| Exploration expenses | 148 | 85 | — | 553 | (f) | 786 |
| Depreciation, depletion and amortization | 1,866 | 214 | 173 | 36 | | 2,289 |
| Impairments | — | — | 4 | 377 | (g) | 381 |
| Other expenses (a) | 322 | 67 | 26 | 330 | (h) | 745 |
| Taxes other than income | 170 | — | 15 | 6 | | 191 |
| Net interest and other | — | — | — | 180 | | 180 |
| Income tax provision (benefit) | (146) | 56 | (43) | (413) | (i) | (546) |
| Segment income (loss) / Net income (loss) | $(267) | $93 | $(107) | $(1,130) | | $(1,411) |
| Capital expenditures (b) | $2,048 | $275 | $26 | $26 | | $2,375 |

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Unrealized gain on commodity derivative instruments.
(d) Partial impairment of investment in equity-method investee (see Note 14).
(e) Includes loss on sale of East Africa exploration acreage (see Note 6.).
(f) Unproved property impairments associated with lower forecasted commodity prices and change in conventional exploration strategy (see Note 13).
(g) Proved property impairments (See Note 14).
(h) Includes pension settlement loss of $99 million (see Note 8) and severance related expenses associated with workforce reductions of $47 million.
(i) Includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase (see Note 9).

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8. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Service cost | $6 | $11 | $1 | $ — |
| Interest cost | 9 | 12 | 3 | 3 |
| Expected return on plan assets | (12 ) | (17 ) | — | — |
| Amortization: | | | | |
| – prior service cost (credit) | (2 ) | (3 ) | (1 ) | (1 ) |
| – actuarial loss | 4 | 5 | — | 1 |
| Net settlement loss [(a)] | 14 | 18 | — | — |
| Net curtailment loss [(b)] | — | 4 | — | — |
| Net periodic benefit cost | $19 | $30 | $3 | $ 3 |

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Service cost | $18 | $35 | $3 | $ 2 |
| Interest cost | 30 | 39 | 8 | 8 |
| Expected return on plan assets | (40 ) | (53 ) | — | — |
| Amortization: | | | | |
| – prior service cost (credit) | (7 ) | (4 ) | (3 ) | (3 ) |
| – actuarial loss | 11 | 19 | — | 1 |
| Net settlement loss [(a)] | 93 | 99 | — | — |
| Net curtailment loss (gain) [(b)] | — | 5 | — | (4 ) |
| Net periodic benefit cost | $105 | $140 | $8 | $ 4 |

(a) Settlements are recognized as they occur, once it is probable that lump sum payments from a plan for a given year will exceed the plan's total service and interest cost for that year.

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

During the first nine months of 2016, we recorded the effects of settlements of our U.S. pension plans. As required, we remeasured the plans' assets and liabilities as of the applicable balance sheet dates. The cumulative effects of these events are included in the remeasurement and reflected in both the pension liability and net periodic benefit cost.

During the first nine months of 2016, we made contributions of $48 million to our funded pension plans and we expect to make additional contributions up to an estimated $16 million over the remainder of 2016. During the first nine months of 2016, we made payments of $47 million and $16 million related to unfunded pension plans and other postretirement benefit plans, respectively.

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9. Income Taxes

Effective Tax Rate

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 is reported in the "Not Allocated to Segments" column of the tables in Note 7. For the three-month and nine-month periods in 2016 and 2015, our effective income tax rates were as follows:

| | 2016 | 2015 |
|---|---|---|
| Three months ended September 30 | 34 % | 35 % |
| Nine months ended September 30 | 37 % | 28 % |

In Libya, reliable estimates of 2016 and 2015 annual ordinary income from our Libyan operations could not be made, and the range of possible scenarios in the worldwide annual effective tax rate calculation demonstrates significant variability. Thus, the tax benefit applicable to Libyan ordinary loss was recorded as a discrete item in the first nine months of 2016 and 2015. For the first nine months of 2016 and 2015, estimated annual effective tax rates were calculated excluding Libya and applied to consolidated ordinary income (loss). Excluding Libya, the effective tax rates would be 30% and 35% for the third quarters 2016 and 2015, and 35% and 27% for the first nine months of 2016 and 2015.

The rate change between years for the third quarter was driven by a shift in jurisdictional income and the impact of tax legislation enacted by the U.K. government on September 15, 2016 reducing the rate of the Petroleum Revenue Tax (PRT) from 35% to 0% and reducing the Supplemental Charge Tax (SCT) from 20% to 10%. As a result of this legislation, we reduced our deferred tax asset by $6 million and recorded an expense in the third quarter of 2016. The rate change between years for the first nine months was driven by a shift in jurisdictional income and tax legislation enacted by the Alberta government in Canada on June 29, 2015 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

In connection with our assessment of the realizability of our deferred tax assets, 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. This assessment requires analysis of all available positive and negative evidence, including losses in recent years as well as forecasts of future income, assessment of future business assumptions and applicable tax planning strategies. We expect to be in a cumulative loss position in 2017 which constitutes significant objective negative evidence. However, we have concluded that our long-term commodity price forecast, proved reserves and available tax planning strategies provide sufficient positive evidence to support the net deferred tax assets recorded as of September 30, 2016. Future increases to our valuation allowance are possible if our estimates and assumptions (particularly as they relate to our long-term commodity price forecast) are revised such that they reduce estimates of future taxable income during the carryforward period.

10. Short-term Investments

As of September 30, 2015, we held short-term investments comprised of bank time deposits with original maturities of greater than three months and remaining maturities of less than twelve months. These short-term investments, which were classified as held-to-maturity investments and recorded at amortized cost, matured in the fourth quarter of 2015.

11. 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.

| (In millions) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Liquid hydrocarbons, natural gas and bitumen | $ 26 | $ 35 |
| Supplies and other items | 195 | 278 |
| Inventories, at cost | $ 221 | $ 313 |

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12. Property, Plant and Equipment, net of Accumulated Depreciation, Depletion and Amortization

| (In millions) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| North America E&P | $ 14,391 | $ 15,226 |
| International E&P | 2,440 | 2,533 |
| Oil Sands Mining | 9,043 | 9,197 |
| Corporate | 102 | 105 |
| Net property, plant and equipment | $ 25,976 | $ 27,061 |

Due to civil unrest, our Libya operations were interrupted in mid-2013 as a result of the shutdown of the Es-Sider crude oil terminal, and while temporarily re-opened in July 2014, operations were again interrupted in December 2014. Force Majeure was lifted on September 14, 2016 and production resumed on October 2, 2016 at our Waha concession. The Libya National Oil Corporation has commenced lifting from the Ras Lanuf crude oil terminal and liftings from the Es-Sider terminal may resume as early as the fourth quarter of 2016.

As of September 30, 2016, our net property, plant and equipment investment in Libya is $770 million, and total proved reserves (unaudited) in Libya as of December 31, 2015 are 235 million barrels of oil equivalent ("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 exceed the carrying value of $770 million by a material amount. However, changes in management's forecast assumptions may cause us to reassess our assets in Libya for impairment and could result in non-cash impairment charges in the future.

Exploratory well costs capitalized greater than one year after completion of drilling were $118 million and $85 million as of September 30, 2016 and December 31, 2015. The $33 million increase primarily relates to the Alba Block Sub Area B offshore Equatorial Guinea where the Rodo well reached total depth in the first quarter of 2015. We have since completed a seismic feasibility study and continue to finalize next steps in the Alba Block Sub Area B exploration program.

13. Impairments and Exploration Expenses

The continued decline of commodity prices resulted in a downward revision of our long-term commodity price assumptions which triggered an assessment of certain of our long-lived assets related to oil and gas producing properties for impairment as of September 30, 2016. Similarly, in 2015, a downward revision of our long-term commodity price assumptions triggered an assessment of our long-lived assets related to oil and gas producing properties for impairment as of September 30, 2015. Further changes in management's forecast assumptions may cause us to reassess our long-lived assets for impairment and could result in non-cash impairment charges in the future.

The following table summarizes impairment charges of proved properties:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in millions) | 2016 | 2015 | 2016 | 2015 |
| Total impairments | $ 47 | $ 337 | $ 48 | $ 381 |

Impairments for the three and nine months ended September 30, 2016 consisted primarily of conventional non-core proved properties in Oklahoma as a result of lower forecasted long-term commodity prices.

Impairments for the three and nine months ended September 30, 2015 consisted primarily of proved properties in Colorado and the Gulf of Mexico as a result of lower forecasted commodity prices. See Note 7 for relevant detail regarding segment presentation and Note 14 for fair value measurements related to impairments of proved properties.

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The following table summarizes the components of exploration expenses:

| (In millions) | Three Months Ended September 30, 2016 | 2015 | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|---|---|
| Exploration Expenses | | | | |
| Unproved property impairments | $28 | $563 | $172 | $612 |
| Dry well costs | 9 | (3) | 31 | 96 |
| Geological and geophysical | 1 | 8 | 1 | 23 |
| Other | 45 | 17 | 92 | 55 |
| Total exploration expenses | $83 | $585 | $296 | $786 |

Unproved property impairments for the nine months ended September 30, 2016 primarily consist of non-cash charges of $118 million as a result of our decision to not drill any of our remaining Gulf of Mexico undeveloped leases. Included in the unproved property impairments for the three and nine months ended September 30, 2015 are non-cash charges of $553 million as a result of changes in our conventional exploration strategy (Gulf of Mexico and Harir block in the Kurdistan Region of Iraq) and lower forecasted commodity prices (Colorado). See Note 7 for relevant detail regarding segment presentation.

14. Fair Value Measurements

Fair Values - Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of September 30, 2016 and December 31, 2015 by fair value hierarchy level.

| (In millions) | September 30, 2016 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Derivative instruments, assets | | | | |
| Commodity (a) | $— | $ 4 | $ — | $ 4 |
| Interest rate | — | 10 | — | 10 |
| Derivative instruments, assets | $— | $ 14 | $ — | $ 14 |
| Derivative instruments, liabilities | | | | |
| Commodity (a) | $— | $ 43 | $ — | $ 43 |
| Derivative instruments, liabilities | $— | $ 43 | $ — | $ 43 |

(a) Derivative instruments are recorded on a net basis in our balance sheet (see Note 15).

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

(a) Derivative instruments are recorded on a net basis in our balance sheet (see Note 15).

Commodity derivatives include three-way collars, two-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 commodity 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.

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Both our interest rate swaps and forward starting interest rate swaps are measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs. See Note 15 for additional discussion of the types of derivative instruments we use.

Fair Values – Goodwill

Unlike long-lived assets, goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Goodwill is tested for impairment at the reporting unit level. We estimate the fair value of our International E&P reporting unit using a combination of market and income approaches. 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 pricing, estimated quantities of liquid hydrocarbons and natural gas proved and probable reserves, estimated timing of production, discount rates, future capital requirements, operating expenses and tax rates. The assumptions used in the income approach are consistent with those that management uses to make business decisions. These valuations methodologies represent Level 3 fair value measurements. We performed our annual impairment test in April 2016 and concluded no impairment was required. While the fair value of our International E&P reporting unit exceeded the book value, subsequent commodity price and/or common stock declines may cause us to reassess our goodwill for impairment and could result in non-cash impairment charges in the future.

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.

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| (In millions) | Fair Value | Impairment | Fair Value | Impairment |
| Long-lived assets held for use | $15 | $ 47 | $41 | $ 337 |

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| (In millions) | Fair Value | Impairment | Fair Value | Impairment |
| Long-lived assets held for use | $15 | $ 48 | $58 | $ 381 |

The continued decline of commodity prices resulted in a downward revision of our long-term commodity price assumptions which triggered an assessment of certain of our long-lived assets related to oil and gas producing properties for impairment as of September 30, 2016. Similarly, in 2015, a downward revision of our long-term commodity price assumptions triggered an assessment of our long-lived assets related to oil and gas producing properties for impairment as of September 30, 2015. Further changes in management's forecast assumptions may cause us to reassess our long-lived assets for impairment and could result in non-cash impairment charges in the future. 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. 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.

2016 - North America E&P

In the third quarter of 2016, impairments of $47 million were recorded primarily consisting of conventional non-core proved properties in Oklahoma as a result of lower forecasted long-term commodity prices, to an aggregate fair value of $15 million.

2015- 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 a non-cash 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 6). The fair values were measured using a probability weighted income approach based on both the anticipated sales price and a held-for-use model.

2015- 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 fair value of $604 million. This impairment was reflected in income equity method investments in our consolidated statements of income.

Fair Values – Financial Instruments

Our current assets and liabilities include financial instruments, the most significant of which are receivables, long-term debt and payables. We believe the carrying values of our receivables 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 credit rating, and (3) our historical incurrence of and expected future insignificant bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding receivables, payables and derivative financial instruments, and their reported fair values by individual balance sheet line item at September 30, 2016 and December 31, 2015.

| | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| (In millions) | Fair Value | Carrying Amount | Fair Value | Carrying Amount |
| Financial assets | | | | |
| Other noncurrent assets | $112 | $ 118 | $104 | $ 118 |
| Total financial assets | $112 | $ 118 | $104 | $ 118 |
| Financial liabilities | | | | |
| Other current liabilities | $49 | $ 59 | $34 | $ 33 |
| Long-term debt, including current portion (a) | 7,345 | 7,292 | 6,723 | 7,291 |
| Deferred credits and other liabilities | 123 | 117 | 97 | 95 |
| Total financial liabilities | $7,517 | $ 7,468 | $6,854 | $ 7,419 |

(a) Excludes capital leases, debt issuance costs and interest rate swap adjustments.

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.

15. Derivatives

For further information regarding the fair value measurement of derivative instruments, see Note 14. 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 where they appear on the consolidated balance sheets.

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| | September 30, 2016 | | | |
|---|---|---|---|---|
| (In millions) | Asset | Liability | Net Asset | Balance Sheet Location |
| Fair Value Hedges | | | | |
| Interest rate | $8 | $ — | $ 8 | Other noncurrent assets |
| Cash Flow Hedges | | | | |
| Interest rate | 2 | — | 2 | Other noncurrent assets |
| Total Designated Hedges | $10 | $ — | $ 10 | |

| | September 30, 2016 | | | |
|---|---|---|---|---|
| (In millions) | Asset | Liability | Net Liability | Balance Sheet Location |
| Not Designated as Hedges | | | | |
| Commodity | $4 | $ 30 | $ 26 | Other current liabilities |
| Commodity | — | 13 | 13 | Deferred credits and other liabilities |
| Total Not Designated as Hedges | $4 | $ 43 | $ 39 | |

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

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.

| | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| 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 | 5.01 % | $600 | 4.73 % |
| March 15, 2018 | $300 | 4.86 % | $300 | 4.66 % |

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

| | | Gain (Loss) | | | |
|---|---|---|---|---|---|
| | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (In millions) | Income Statement Location | 2016 | 2015 | 2016 | 2015 |

| | | | | | |
|---|---|---|---|---|---|
| Derivative | | | | | |
| Interest rate | Net interest and other | $(4) | $4 | $ — | $ 7 |
| Hedged Item | | | | | |
| Long-term debt | Net interest and other | $4 | $(4) | $ — | $ (7) |

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Derivatives Designated as Cash Flow Hedges

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. Derivative instruments designated as cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The effective portion of changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is reclassified to net income when the underlying forecasted transaction is recognized in net income. Ineffective portions of a cash flow hedge's change in fair value are recognized currently within net interest and other on the consolidated statements of income. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in other comprehensive income is immediately reclassified into net income.

During the third quarter of 2016, we entered into forward starting interest rate swaps to hedge the variations in cash flows related to fluctuations in long term interest rates from debt that is probable to be refinanced by us in 2018, specifically interest rate risk associated with future changes in the benchmark treasury rate. The occurrence of the forecasted transaction is probable and each respective derivative contract can be tied to an anticipated underlying dollar notional amount. At conclusion of the hedge in the first quarter of 2018, the final value will be reclassified from accumulated other comprehensive income into earnings. At September 30, 2016, the forward starting interest rate swaps continued to qualify as an effective hedge and the ineffective portion was not material.

The following table presents, by maturity date, information about our forward starting interest rate swap agreements, including the rate.

| | September 30, 2016 | |
|---|---|---|
| Maturity Dates | Aggregate Notional Amount (in millions) | Weighted Average, LIBOR Fixed Rate |
| March 15, 2018 | $750 | 1.57% |

The following table sets forth the net impact of the derivatives designated as cash flow hedges on other comprehensive income (loss).

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Cash Flow Hedges | | | | |
| Beginning balance | $ — | $ — | $ — | $ — |
| Change in fair value recognized in other | 2 | — | 2 | — |

| | | | | |
|---|---|---|---|---|
| comprehensive income | | | | |
| Reclassification from other comprehensive income | — | — | — | |
| Ending balance | $ 2 | $ — | $ 2 | $ — |

At September 30, 2016, accumulated other comprehensive income included deferred gains of $1 million, net of tax, related to interest rate cash flow hedges. We do not expect any reclassification to earnings as an adjustment to net interest and other during the next 12 months.

Derivatives not Designated as Hedges

We have entered into multiple crude oil and natural gas derivatives indexed to NYMEX WTI and Henry Hub related to a portion of our forecasted North America E&P sales through December 2017. These commodity derivatives consist of three-way collars, two-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 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/Henry Hub price plus the difference between the floor and the sold put price. These commodity derivatives were not designated as hedges. The following table sets forth outstanding derivative contracts as of September 30, 2016 and the weighted average prices for those contracts:

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Crude Oil

| | 2016 | 2017 | | | |
|---|---|---|---|---|---|
| | Fourth Quarter | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| Three-Way Collars [(a)] | | | | | |
| Volume (Bbls/day) | 47,000 | 30,000 | 30,000 | — | — |
| Price per Bbl: | | | | | |
| Ceiling | $55.37 | $58.19 | $58.19 | — | — |
| Floor | $50.23 | $49.33 | $49.33 | — | — |
| Sold put | $40.96 | $42.67 | $42.67 | — | — |
| Sold call options [(b)] | | | | | |
| Volume (Bbls/day) | 10,000 | 35,000 | 35,000 | 35,000 | 35,000 |
| Price per Bbl | $72.39 | $61.91 | $61.91 | $61.91 | $61.91 |
| Two-way Collars | | | | | |
| Volume (Bbls/day) | 10,000 | — | — | — | — |
| Price per Bbl: | | | | | |
| Ceiling | $50.00 | — | — | — | — |
| Floor | $41.55 | — | — | — | — |

(a) Subsequent to September 30, 2016, we entered into 10,000 Bbls/day of three-way collars for January - June 2017 with a ceiling price of $58.27, a floor price of $49.50, and a sold put price of $42.50.

(b) Call options settle monthly.

Natural Gas

| | 2016 | 2017 | | | |
|---|---|---|---|---|---|
| | Fourth Quarter | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| Three-Way Collars [(a)] | | | | | |
| Volume (MMBtu/day) | 20,000 | 60,000 | 60,000 | 60,000 | 60,000 |
| Price per MMBtu | | | | | |
| Ceiling | $2.93 | $3.46 | $3.46 | $3.46 | $3.46 |
| Floor | $2.50 | $2.84 | $2.84 | $2.84 | $2.84 |
| Sold put | $2.00 | $2.35 | $2.35 | $2.35 | $2.35 |

(a) On our 2016 collars, the counterparty has the option to execute fixed-price swaps (swaptions) at a weighted average price of $2.93 per MMBtu indexed to NYMEX Henry Hub, which is exercisable on December 22, 2016. If the counterparty exercises, the term of the fixed-price swaps would be for the calendar year 2017 and, if all such options are exercised, 20,000 MMBtu per day.

The mark-to-market impact and settlement of these commodity derivative instruments appears in sales and other operating revenues in our consolidated statements of income for the three and nine month periods ended September 30, 2016. The impact was a net gain of $42 million and a net loss of $48 million compared to a net gain of $108 million and $91 million for the same respective periods in 2015. Net cash received from settlements of commodity derivative instruments for the three and nine month periods ended September 30, 2016 was $8 million and $54 million compared to $18 million and $23 million for both of the respective periods in 2015.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

16. Incentive Based Compensation

Stock options, restricted stock awards and restricted stock units

The following table presents a summary of activity for the first nine months of 2016:

| | Stock Options | | Restricted Stock Awards & Units | |
|---|---|---|---|---|
| | Number of Shares | Weighted Average Exercise Price | Awards | Weighted Average Grant Date Fair Value |
| Outstanding at December 31, 2015 | 12,665,419 | $29.97 | 4,017,344 | $30.76 |
| Granted | 1,680,000 [(a)] | $7.22 | 5,247,751 | $7.93 |
| Options Exercised/Stock Vested | — | — | (1,264,325) | $32.52 |
| Canceled | (1,936,084) | $23.95 | (1,119,975) | $19.92 |
| Outstanding at September 30, 2016 | 12,409,335 | $27.83 | 6,880,795 | $14.79 |

[(a)] The weighted average grant date fair value of stock option awards granted was $1.97 per share.

Stock-based performance unit awards

During the first nine months of 2016, we granted 1,205,517 stock-based performance units to certain officers. The grant date fair value per unit was $3.72. In September of 2016, 377,857 stock-based performance units were canceled.

17. Debt

Revolving Credit Facility

As of September 30, 2016, we had no borrowings against our revolving credit facility (the "Credit Facility"), as described below.

In March 2016, we increased our $3.0 billion unsecured Credit Facility by $300 million to a total of $3.3 billion. 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 September 30, 2016, we were in compliance with this covenant with a debt-to-capitalization ratio of 28%.

Debt Issuance

In the second quarter of 2015, we issued $2 billion aggregate principal amount of unsecured senior notes and used the aggregate net proceeds to repay our $1 billion 0.90% senior notes November 1, 2015, and for general corporate purposes.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

18. Reclassifications Out of Accumulated Other Comprehensive Loss

The following table presents a summary of amounts reclassified from accumulated other comprehensive loss:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|
| (In millions) | 2016 | 2015 | 2016 | 2015 | Income Statement Line |
| Postretirement and postemployment plans | | | | | |
| Amortization of actuarial loss | $(4) | $(6) | $(11) | $(20) | General and administrative |
| Net settlement loss | (14) | (18) | (93) | (99) | General and administrative |
| Net curtailment loss | — | (4) | — | (1) | General and administrative |
| | (18) | (28) | (104) | (120) | Income (loss) from operations |
| | 6 | 10 | 38 | 44 | Benefit for income taxes |
| Total reclassifications to expense | $(12) | $(18) | $(66) | $(76) | Net income (loss) |

19. Stockholder's Equity

In March 2016, we issued 166,750,000 shares of our common stock, par value $1 per share, at a price of $7.65 per share, excluding underwriting discounts and commissions, for net proceeds of $1,236 million. The proceeds were used to strengthen our balance sheet and for general corporate purposes, including funding a portion of our Capital Program.

20. Supplemental Cash Flow Information

| | Nine Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| Net cash (used in) operating activities: | | |
| Interest paid (net of amounts capitalized) | $(243) | $(200) |
| Income taxes paid to taxing authorities | (68) | (174) |
| Noncash investing activities: | | |
| Asset retirement cost increase | $3 | $12 |
| Asset retirement obligations assumed by buyer | 86 | 23 |

21. Commitments and Contingencies

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

We have incurred and will continue to incur 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.

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Item 2. 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 preceding consolidated financial statements and notes in Item 1.

Executive Overview

We are an independent global exploration and production company based in Houston, Texas with operations in North America, Europe and Africa and a focus on U.S. unconventional resource plays. Total proved reserves were 2.2 billion boe at December 31, 2015 and total assets were $32 billion at September 30, 2016.

Our significant strategic actions and financial results include the following:

- Strengthened balance sheet
  - At the end of the third quarter of 2016, we had $5.3 billion of liquidity, comprised of $2.0 billion in cash and an undrawn $3.3 billion revolving credit facility
  - Cash-adjusted debt-to-capital ratio of 22% at September 30, 2016, as compared with 25% at December 31, 2015
- Focused on cost reductions
  - Decreased production expenses per boe in the third quarter of 2016, as compared to the same period last year in the North America E&P segment by 23% to $5.70 per boe and in the International E&P segment by 27% to $4.05 per boe
  - Eagle Ford completed well costs were down to less than $4 million per well on average, which is a 20% decrease in the current quarter compared to the same quarter last year
  - General and administrative expenses dropped $20 million versus the same quarter last year due to cost savings realized from the 2015 workforce reductions
- Simplifying and concentrating portfolio
  - In the quarter we closed on the Oklahoma STACK acquisition for $904 million, funded with cash on hand
  - Closed the sale of non-operated CO2 and waterflood assets in West Texas and New Mexico for $235 million in late October, bringing our non-core asset sales announced or closed to more than $1.5 billion since August 2015
- Operational updates
  - Net sales volumes increased 78% in Oklahoma in the third quarter of 2016 compared to the same quarter last year; with Eagle Ford experiencing a 23% decrease over the same period
  - Plan to increase North American E&P segment rig activity by 50% adding four rigs in the fourth quarter
  - Net sales volumes in E.G. increased 14% in the third quarter of 2016 versus the same quarter last year due primarily to the completion of the Alba B3 compression project
- Financial results
  - Cash provided by operating activities of $618 million for the first nine months of 2016, reflecting average crude oil and condensate price realizations of $36.82 per bbl.
  - Improving our net loss per share of $0.23 in the third quarter of 2016 as compared to net loss per share of $1.11 in the same period last year. Included in the third quarter 2016 net loss are:
    - Expense associated with the termination payment for our Gulf of Mexico deepwater drilling rig of $113 million, pre-tax
    - Unrealized gain on our commodity derivative instruments totaling $25 million, pre-tax
    - Net gains on disposal of non-core assets totaling $47 million, pre-tax
    - Non-cash charges totaling $47 million pre-tax, as a result of impairments of non-core proved properties

Operations

The following table presents a summary of our sales volumes for each of our segments. Refer to the Results of Operations for a price-volume analysis for each of the segments.

| Net Sales Volumes | Three Months Ended September 30, 2016 | 2015 | Increase (Decrease) | Nine Months Ended September 30, 2016 | 2015 | Increase (Decrease) |
|---|---|---|---|---|---|---|
| North America E&P (mboed) | 216 | 261 | (17)% | 226 | 273 | (17)% |
| International E&P (mboed) | 126 | 119 | 6% | 114 | 115 | (1)% |
| Oil Sands Mining (mbbld) [(a)] | 65 | 65 | —% | 58 | 51 | 14% |
| Total (mboed) | 407 | 445 | (9)% | 398 | 439 | (9)% |

[(a)] Includes blendstocks

North America E&P

Net sales volumes in the segment were lower in the third quarter of 2016 primarily as a result of 30 mboed relating to the dispositions of certain non-core assets (Gulf of Mexico, East Texas, North Louisiana, Wyoming and Oklahoma) during the last six months of 2015 through August of 2016, as well as base declines and lower completion activity resulting in fewer wells brought to sales. The following tables provide details regarding net sales volumes, sales mix and operational drilling activity for our significant operations within this segment:

| Net Sales Volumes | Three Months Ended September 30, 2016 | 2015 | Increase (Decrease) | Nine Months Ended September 30, 2016 | 2015 | Increase (Decrease) |
|---|---|---|---|---|---|---|
| Equivalent Barrels (mboed) | | | | | | |
| Eagle Ford | 97 | 126 | (23)% | 109 | 137 | (20)% |
| Oklahoma Resource Basins | 41 | 23 | 78% | 32 | 24 | 33% |
| Bakken | 54 | 61 | (11)% | 55 | 59 | (7)% |
| Other North America [(a)] | 24 | 51 | (53)% | 30 | 53 | (43)% |
| Total North America E&P | 216 | 261 | (17)% | 226 | 273 | (17)% |

[(a)] Includes 10 mboed for the first nine months ending September 30, 2016 of mainly Wyoming production, which was disposed of in June 2016. Includes 30 mboed for the three months ending September 30, 2015 and 31 mboed for the first nine months ending September 30, 2015 of Gulf of Mexico, Wyoming, and other conventional onshore U.S. production, which was disposed of during the sale of non-core assets in the second half of 2015 and continuing into 2016.

| Sales Mix - U.S. Resource Plays | Three Months Ended September 30, 2016<br>Crude oil and condensate | Natural gas liquids | Natural gas |
|---|---|---|---|
| Eagle Ford | 56% | 23% | 21% |
| Oklahoma Resource Basins | 26% | 26% | 48% |
| Bakken | 81% | 11% | 8% |

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Gross Operated | | | | |
| Eagle Ford: | | | | |
| Wells drilled to total depth | 33 | 51 | 131 | 198 |
| Wells brought to sales | 36 | 57 | 116 | 200 |
| Oklahoma Resource Basins: | | | | |
| Wells drilled to total depth | 9 | 4 | 20 | 17 |
| Wells brought to sales | 12 | 8 | 20 | 16 |
| Bakken: | | | | |
| Wells drilled to total depth | — | 5 | 3 | 30 |
| Wells brought to sales | 3 | 5 | 13 | 51 |

- Eagle Ford – During the third quarter of 2016, we brought 36 gross operated wells to sales, of which 20 were Lower Eagle Ford, 15 were Upper Eagle Ford and 1 was Austin Chalk. Production decreases were in line with expectations and due to base declines and lower completion activity. We have plans to increase activity from four to six rigs in the fourth quarter.
- Oklahoma Resource Basins – Of the 12 gross operated wells brought to sales in the third quarter of 2016, 10 were in the STACK Meramec and 2 wells were in the SCOOP Woodford. Two of the STACK wells and one of the SCOOP wells were extended laterals. We also participated in 17 outside-operated wells during the third quarter of 2016, 9 of which were in the STACK and 8 were in the SCOOP.

We closed the STACK acquisition in Oklahoma on August 1, 2016 and added a second drilling rig on the acreage in the third quarter. We expect to further increase our rig activity from four to five rigs in the fourth quarter, with activity focused in the STACK.

- Bakken – Of the 3 gross operated wells brought to sales in the third quarter of 2016, 2 were in the Three Forks formation and 1 in the Middle Bakken formation. Strong well productivity from the Clarks Creek and Maggie pad along with high reliability continued to support base production in the current quarter. We plan to return to drilling in the Bakken with one rig to be added late in the fourth quarter.
- Other North America – Net sales volumes declined in the third quarter of 2016 primarily due to the aforementioned non-core asset sales.

The Gunflint field located in Mississippi Canyon block 948 in the Gulf of Mexico, achieved first production in the third quarter of 2016. We hold an 18% non-operated working interest in the field.

International E&P

Net sales volumes in the segment were higher in the third quarter of 2016 primarily as a result of the completion and start-up of E.G. Alba field compression project when compared to the third quarter of 2015. The following table provides details regarding net sales volumes for our significant operations within this segment.

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| Net Sales Volumes | 2016 | 2015 | Increase (Decrease) | 2016 | 2015 | Increase (Decrease) |
| Equivalent Barrels (mboed) | | | | | | |
| Equatorial Guinea | 115 | 101 | 14% | 100 | 96 | 4% |
| United Kingdom[(a)] | 11 | 18 | (39)% | 14 | 19 | (26)% |
| Total International E&P | 126 | 119 | 6% | 114 | 115 | (1)% |
| Equity Method Investees | | | | | | |
| LNG (mtd) | 6,620 | 5,700 | 16% | 5,584 | 5,653 | (1)% |
| Methanol (mtd) | 1,529 | 1,125 | 36% | 1,371 | 895 | 53% |
| Condensate & LPG (boed) | 16,766 | 13,427 | 25% | 12,775 | 11,746 | 9% |

(a) Includes natural gas acquired for injection and subsequent resale of 5 mmcfd and 8 mmcfd for the third quarters of 2016 and 2015, and 5 mmcfd and 8 mmcfd for the first nine months of 2016 and 2015.

- Equatorial Guinea – Third quarter 2016 net sales were higher compared to the same quarter of 2015 as a result of the completion and start-up of Alba field compression project, which achieved first gas in July. The project is expected to maintain the production plateau for an additional two years and extend field life up to eight years.
- United Kingdom – Net sales volumes in the first nine months of 2016 were lower due to the timing of Brae liftings and repair activities at the Brae Alpha facility following a process pipe failure in late 2015. Production was restored at the facility in late April. Higher overall production efficiency at the remaining Brae facilities and improved reliability from the outside-operated Foinaven field partially offset the Brae Alpha outage.
- Libya – Force Majeure was lifted on September 14, 2016 and production resumed on October 2, 2016 at our Waha concession. The Libya National Oil Corporation has commenced lifting from the Ras Lanuf crude oil terminal and liftings from the Es-Sider terminal may resume as early as the fourth quarter of 2016.

Oil Sands Mining

Our net synthetic crude oil sales volumes were 65 mbbld and 58 mbbld in the third quarter and first nine months of 2016 compared to 65 mbbld and 51 mbbld in the same periods of 2015. Sales volumes increased in the first nine months relative to the same periods of 2015 as a result of strong mine and upgrader performance coupled with less planned maintenance. We hold a 20% non-operated working interest in the Athabasca Oil Sands Project.

Market Conditions

Prevailing prices for the crude oil, NGLs and natural gas that we produce significantly impact our revenues and cash flows. The benchmark prices for crude oil, NGLs and natural gas were mostly lower in the third quarter and first nine months of 2016 as compared to the same period in 2015; as a result, we experienced declines in our price realizations associated with those benchmarks. Additional detail on market conditions, including our average price realizations and benchmarks for crude oil, NGLs and natural gas relative to our operating segments, follows.

North America E&P

The following table presents our average price realizations and the related benchmarks for crude oil, NGLs and natural gas for the third quarter and first nine months of 2016 and 2015.

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Decrease | 2016 | 2015 | Increase (Decrease) |
| Average Price Realizations [a] | | | | | | |
| Crude Oil and Condensate (per bbl) [b] | $41.35 | $41.37 | —% | $36.37 | $45.27 | (20 )% |
| Natural Gas Liquids (per bbl) | 12.44 | 11.88 | 5% | 11.79 | 13.67 | (14 )% |
| Total Liquid Hydrocarbons (per bbl) | 34.00 | 35.75 | (5)% | 30.79 | 39.55 | (22 )% |
| Natural Gas (per mcf) | 2.67 | 2.75 | (3)% | 2.22 | 2.84 | (22 )% |
| Benchmarks | | | | | | |
| WTI crude oil (per bbl) | $44.94 | $46.50 | (3)% | $41.53 | $51.01 | (19 )% |
| LLS crude oil (per bbl) | 46.52 | 50.22 | (7)% | 43.19 | 55.33 | (22 )% |
| Mont Belvieu NGLs (per bbl) [c] | 17.04 | 15.86 | 7% | 16.21 | 17.28 | (6 )% |
| Henry Hub natural gas (per mmbtu) | 2.81 | 2.77 | 1% | 2.29 | 2.80 | (18 )% |

(a) Excludes gains or losses on commodity derivative instruments.

(b) Inclusion of realized gains on crude oil derivative instruments would have increased average realizations by $1.55 per bbl and $1.87 per bbl for the third quarter 2016 and 2015, and $1.10 per bbl and $0.69 per bbl for the first nine months of 2016 and 2015.

(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 NGL 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, NGLs, and natural gas for the third quarter and first nine months of 2016 and 2015.

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Increase (Decrease) | 2016 | 2015 | Increase (Decrease) |
| Average Price Realizations | | | | | | |
| Crude Oil and Condensate (per bbl) | $41.45 | $46.18 | (10)% | $38.99 | $50.51 | (23 )% |
| Natural Gas Liquids (per bbl) | 1.93 | 2.69 | (28)% | 2.25 | 3.08 | (27 )% |
| Liquid Hydrocarbons (per bbl) | 30.40 | 35.88 | (15)% | 28.96 | 39.21 | (26 )% |
| Natural Gas (per mcf) | 0.46 | 0.59 | (22)% | 0.52 | 0.71 | (27 )% |
| Benchmark | | | | | | |
| Brent (Europe) crude oil (per bbl) [a] | $45.79 | $50.23 | (9%) | $41.67 | $55.28 | (25 )% |

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

Liquid hydrocarbons – Our U.K. liquid hydrocarbon production is generally sold in relation to the Brent crude benchmark. Our production from E.G. is condensate, which receives lower prices than crude oil.

Our NGL and natural gas sales in the International E&P segment originate primarily from our E.G. operations and are sold to our equity method investees under fixed-price, term contracts; therefore, our reported average realized prices for NGLs and natural gas will not fully track market price movements. The equity affiliates then utilize, process and sell the NGLs at market prices and natural gas at fixed prices under long-term contracts, with our share of their income/loss reflected in the income from equity method investments line on the consolidated statements of income.

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 roughly two-thirds of the normal output mix have historically tracked movements in WTI and one-third have historically tracked movements in the Canadian heavy crude oil marker, primarily WCS.

The following table presents our average price realizations and the related benchmarks for the third quarter and first nine months of 2016 and 2015.

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Decrease | 2016 | 2015 | Increase (Decrease) |
| Average Price Realizations | | | | | | |
| Synthetic Crude Oil (per bbl) | $39.59 | $39.49 | —% | $35.46 | $42.26 | (16 %) |
| Benchmarks | | | | | | |
| WTI crude oil (per bbl) | $44.94 | $46.50 | (3%) | $41.53 | $51.01 | (19 %) |
| WCS crude oil (per bbl)[a] | 31.44 | 33.16 | (5%) | 27.65 | 37.80 | (27 %) |

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

Results of Operations

Three Months Ended September 30, 2016 vs. Three Months Ended September 30, 2015

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

| (In millions) | Three Months Ended September 30, 2016 | 2015 |
|---|---|---|
| Sales and other operating revenues, including related party | | |
| North America E&P | $604 | $796 |
| International E&P | 152 | 182 |
| Oil Sands Mining | 239 | 242 |
| Segment sales and other operating revenues, including related party | $995 | $1,220 |
| Unrealized gain on commodity derivative instruments | 25 | 80 |
| Sales and other operating revenues, including related party | $1,020 | $1,300 |

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) | Three Months Ended September 30, 2015 | Increase (Decrease) Related to Price Realizations | Net Sales Volumes | Three Months Ended September 30, 2016 |
|---|---|---|---|---|
| North America E&P Price-Volume Analysis [(a)] | | | | |
| Liquid hydrocarbons | $ 674 | $(28) | $ (138) | $ 508 |
| Natural gas | 85 | (2) | (5) | 78 |
| Realized gain on commodity derivative instruments | 28 | (11) | | 17 |
| Other sales | 9 | | | 1 |
| Total | $ 796 | | | $ 604 |
| International E&P Price-Volume Analysis | | | | |
| Liquid hydrocarbons | $ 152 | $(22) | $ (5) | $ 125 |
| Natural gas | 24 | (6) | 2 | 20 |
| Other sales | 6 | | | 7 |
| Total | $ 182 | | | $ 152 |
| Oil Sands Mining Price-Volume Analysis | | | | |
| Synthetic crude oil | $ 236 | $2 | $ — | $ 238 |
| Other sales | 6 | | | 1 |
| Total | $ 242 | | | $ 239 |

(a) Three months ended September 30, 2016 includes a net sales volume reduction of 30 mboed related to dispositions in the Gulf of Mexico and other conventional onshore U.S. production.

Income from equity method investments increased $23 million in the third quarter of 2016 from the comparable 2015 period. The improvement is due to an increase in net sales volumes as a result of the completion of the Alba B3 compression project in E.G. during the third quarter of 2016 and the $12 million partial impairment of our investment in an equity method investee in 2015.

Net gain (loss) on disposal of assets increased $156 million in the third quarter of 2016. See Note 6 to the consolidated financial statements for information about dispositions.

Production expenses decreased $111 million. North America E&P declined $66 million primarily due to lower operational, maintenance and labor costs, coupled with lower net sales volumes including the impact of our non-core asset dispositions. International E&P declined $14 million primarily as a result of lower costs resulting from lower U.K. net sales volumes. Contributing to the U.K. decrease was a more favorable exchange rate on expenses. OSM decreased $31 million primarily due to lower condensate purchases and continued cost management, specifically staffing and contract labor.

The third quarter of 2016 production expense rate (expense per boe) for North America E&P declined as cost reductions occurred at a rate faster than our production decline. The expense rate for International E&P declined due to an increase in volumes, combined with reduced maintenance and project costs in the U.K. The OSM expense rate decreased as a result of consistent sales volumes while achieving lower production expenses due to lower condensate purchases, as discussed above.

The following table provides production expense rates for each segment:

| | Three Months Ended September 30, | |
|---|---|---|
| ($ per boe) | 2016 | 2015 |
| Production Expense Rate | | |
| North America E&P | $5.70 | $7.43 |
| International E&P | $4.05 | $5.53 |
| Oil Sands Mining [(a)] | $20.69 | $26.01 |

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

Other operating expenses increased $96 million primarily as a result of the termination payment of our Gulf of Mexico deepwater drilling rig.

Exploration expenses decreased $502 million primarily as a result of a strategic decision in 2015 to reduce our conventional exploration program; as a result, we impaired certain of our leases in the Gulf of Mexico and the Harir block in the Kurdistan Region of Iraq. Further contributing to this decrease was an impairment of unproved property in Colorado, which we deemed uneconomic given our forecasted natural gas prices in the third quarter of 2015. The following table summarizes the components of exploration expenses:

| | Three Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| Exploration Expenses | | |
| Unproved property impairments | $28 | $563 |
| Dry well costs | 9 | (3) |
| Geological and geophysical | 1 | 8 |
| Other | 45 | 17 |
| Total exploration expenses | $83 | $585 |

Depreciation, depletion and amortization decreased $123 million primarily as a result of production volume decreases in North America E&P, and as a result of the non-core asset dispositions. 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 per boe), 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. The DD&A rate for International E&P declined primarily due to sales volume mix changes in the current quarter between E.G. and the U.K. The DD&A rate for OSM declined as a result of a higher proved reserve base in the fourth quarter of 2015.

| | Three Months Ended September 30, | |
|---|---|---|
| ($ per boe) | 2016 | 2015 |
| DD&A Rate | | |

| | | |
|---|---|---|
| North America E&P | $22.37 | $22.84 |
| International E&P | $5.72 | $7.32 |
| Oil Sands Mining | $11.34 | $12.62 |

Impairments decreased $290 million primarily as a result of the third quarter of 2015 non-cash impairment charge of proved properties in Colorado and the Gulf of Mexico as a result of lower forecasted commodity prices. This was partially offset by a $47 million non-cash impairment charge in the third quarter of 2016 relating to conventional non-core proved properties in Oklahoma. See Note 14 to the consolidated financial statements for discussion of the impairment.

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, decreased $7 million in the third quarter of 2016 versus the same period in 2015. The following table summarizes the components of taxes other than income:

| | Three Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| Production and severance | $ 23 | $ 28 |
| Ad valorem | 3 | 2 |
| Other | 13 | 16 |
| Total | $ 39 | $ 46 |

General and administrative expenses decreased $20 million primarily due to cost savings realized from the 2015 workforce reductions and corresponding severance expenses.

Net interest and other increased $12 million primarily due to higher net foreign currency gains in the third quarter of 2015 compared to the current year.

Provision (benefit) for income taxes reflects an effective tax rate of 34% in the third quarter of 2016, as compared to 35% in the third quarter of 2015.

Segment Income (Loss)

Segment income (loss) represents income (loss) from 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. Gains or losses on dispositions, certain impairments, unrealized gains or losses on commodity derivative instruments, pension settlement losses, or other items that affect comparability also are not allocated to operating segments.

The following table reconciles segment income (loss) to net income (loss):

| | Three Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| North America E&P | $(59 ) | $(61 ) |
| International E&P | 59 | 29 |
| Oil Sands Mining | 15 | (11 ) |
| Segment income (loss) | 15 | (43 ) |
| Items not allocated to segments, net of income taxes | (207 ) | (706 ) |
| Net income (loss) | $(192) | $(749) |

North America E&P segment loss slightly decreased by $2 million after-tax primarily due to lower net sales volumes resulting from lower completions activities and non-core asset sales; this decrease was nearly offset by the corresponding impacts of lower net sales volumes to DD&A and production costs.

International E&P segment income increased $30 million after-tax primarily due to a decrease in production costs resulting from lower U.K. sales volumes, lower DD&A expenses and an increase in income from equity investments. This was partially offset by lower price realizations.

Oil Sands Mining segment income increased $26 million after-tax primarily due to lower production costs resulting from lower condensate purchases.

Results of Operations
Nine Months Ended September 30, 2016 vs. Nine Months Ended September 30, 2015
Consolidated Results of Operation
Sales and other operating revenues, including related party are presented by segment in the table below:

| (In millions) | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|
| Sales and other operating revenues, including related party | | |
| North America E&P | $1,714 | $2,639 |
| International E&P | 407 | 575 |
| Oil Sands Mining | 572 | 614 |
| Segment sales and other operating revenues, including related party | $2,693 | $3,828 |
| Unrealized gain (loss) on commodity derivative instruments | (89) | 59 |
| Sales and other operating revenues, including related party | $2,604 | $3,887 |

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) | Nine Months Ended September 30, 2015 | Increase (Decrease) Related to Price Realizations | Net Sales Volumes | Nine Months Ended September 30, 2016 |
|---|---|---|---|---|
| North America E&P Price-Volume Analysis (a) | | | | |
| Liquid hydrocarbons | $ 2,307 | $(419) | $ (420) | $ 1,468 |
| Natural gas | 273 | (53) | (29) | 191 |
| Realized gain on commodity derivative instruments | 33 | 8 | | 41 |
| Other sales | 26 | | | 14 |
| Total | $ 2,639 | | | $ 1,714 |
| International E&P Price-Volume Analysis | | | | |
| Crude oil and condensate | | | | |
| Natural gas liquids | | | | |
| Liquid hydrocarbons | $ 462 | $(113) | $ (30) | $ 319 |
| Natural gas | 83 | (23) | 3 | 63 |
| Other sales | 30 | | | 25 |
| Total | $ 575 | | | $ 407 |
| Oil Sands Mining Price-Volume Analysis | | | | |
| Synthetic crude oil | $ 592 | $(108) | $ 77 | $ 562 |
| Other sales | 22 | | | 10 |
| Total | $ 614 | | | $ 572 |

(a) Includes 10 mboed for the first nine months ending September 30, 2016 of mainly Wyoming production, which was disposed of in June 2016. Nine months ended September 30, 2015 includes net sales volumes of 31mboed related to dispositions in the Gulf of Mexico and other conventional onshore U.S. production.

Marketing revenues for the first nine months of 2016 decreased by $244 million. 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. Because the volume of marketing activity is based on market dynamics, it can fluctuate from period to period. The decrease is related primarily to lower marketed volumes in North America, which were further compounded by a lower commodity price environment.

Income from equity method investments increased $12 million for the first nine months of 2016 primarily due to a partial impairment of our investment in an equity method investee in 2015.

Net gain on disposal of assets increased $389 million for the first nine months of 2016. See Note 6 to the consolidated financial statements for information about dispositions.

Production expenses for the first nine months of 2016 decreased by $327 million compared to the same period of 2015. North America E&P declined $184 million primarily due to lower operational, maintenance and labor costs, coupled with lower net sales volumes including the impact of our non-core asset dispositions. International E&P declined $36 million largely due to lower operational costs resulting from lower U.K. net sales volumes. Also contributing to the U.K. decrease was a more favorable exchange rate on expenses. OSM decreased $107 million primarily due to continued cost management, specifically staffing and contract labor, lower turnaround costs, and a favorable exchange rate on expenses denominated in the Canadian Dollar.

The first nine months of 2016 production expense rate (expense per boe) for North America E&P declined primarily due to cost reductions that occurred at a rate faster than our production decline. The International E&P expense rate decreased in the first nine months of 2016 primarily due to reduced maintenance and project costs in the U.K. The OSM expense rate decreased in the first nine months of 2016 primarily due to lower operational costs.

| | Nine Months Ended September 30, | |
|---|---|---|
| ($ per boe) | 2016 | 2015 |
| Production Expense Rate | | |
| North America E&P | $6.06 | $7.52 |
| International E&P | $4.98 | $6.13 |
| Oil Sands Mining [(a)] | $28.35 | $39.58 |

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

Marketing costs decreased $245 million in the first nine months of 2016 from the comparable 2015 period, consistent with the marketing revenues changes discussed above.

Other operating expenses increased $112 million primarily as a result of the termination payment of our Gulf of Mexico deepwater drilling rig.

Exploration expenses decreased $490 million in the first nine months of 2016 versus the comparable 2015 period. In 2015 we made a strategic decision to reduce the overall level of our conventional exploration program; as a result, we impaired certain leases in the Gulf of Mexico and the Harir block in the Kurdistan Region of Iraq. Further contributing to the prior year increase was an impairment of unproved property in Colorado, which we deemed uneconomic given our forecasted natural gas prices. In 2016, unproved property impairments primarily consisted of non-cash charges related to our decision to not drill our remaining Gulf of Mexico leases. The following table summarizes the components of exploration expenses:

| | Nine Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| Exploration Expenses | | |
| Unproved property impairments | $172 | $612 |
| Dry well costs | 31 | 96 |
| Geological and geophysical | 1 | 23 |
| Other | 92 | 55 |
| Total exploration expenses | $296 | $786 |

Depreciation, depletion and amortization (“DD&A”) decreased $525 million in the first nine months of 2016 from the comparable 2015 period primarily as a result of net sales volume decreases, including the impact of non-core asset dispositions, and also a higher proved reserve base in Eagle Ford. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs; therefore, volumes have an impact on DD&A expense.

The DD&A rate (expense per boe), which is impacted by field-level changes in sales volumes, reserves and capitalized costs, 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 the impact of non-core asset dispositions, and a higher proved reserve base. The DD&A rate for International E&P declined primarily due to sales volume mix changes in E.G. and the U.K. for the first nine months of 2016. The DD&A rate for OSM declined as a result of a higher proved reserve base in the fourth quarter of 2015.

| | Nine Months Ended September 30, | |
|---|---|---|
| ($ per boe) | 2016 | 2015 |
| DD&A Rate | | |
| North America E&P | $21.98 | $25.09 |
| International E&P | $5.89 | $6.87 |
| Oil Sands Mining | $11.34 | $12.60 |

Impairments decreased $333 million in the first nine months of 2016 as a result of the third quarter 2015 non-cash impairment charge related to the proved properties in Colorado and the Gulf of Mexico as a result of lower forecasted commodity prices. This was partially offset by a non-cash impairment charge in the third quarter of 2016 primarily relating to conventional non-core proved properties in Oklahoma. See Note 14 to the consolidated financial statements for discussion of the impairment.

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, decreased $65 million in the first nine months of 2016 from the comparable 2015 period. The following table summarizes the components of taxes other than income:

| | Nine Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| Production and severance | $68 | $102 |
| Ad valorem | 22 | 33 |
| Other | 36 | 56 |
| Total | $126 | $191 |

General and administrative expenses decreased $76 million in the first nine months of 2016 compared to the same period in 2015. This decrease was primarily due to cost savings realized from the 2015 workforce reductions including corresponding severance expenses.

Net interest and other increased $78 million in the first nine months of 2016 compared to same period in 2015. This increase was primarily due to an increase in interest expense as a result of the increase in long-term debt in the second quarter of 2015. See Note 17 to the consolidated financial statements for further discussion.

Provision (benefit) for income taxes reflect effective tax rates of 37% in the first nine months of 2016, as compared to 28% from the comparable 2015 period. See Note 9 to the consolidated financial statements for discussion of the effective tax rate.

Segment Income (Loss)

Segment income (loss) represents income (loss) 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. 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, pension settlement losses, or other items that affect comparability also are not allocated to operating segments.

The following table reconciles segment income (loss) to net income (loss):

| | Nine Months Ended September 30, | |
|---|---|---|
| (In millions) | 2016 | 2015 |
| North America E&P | $(324) | $(267) |
| International E&P | 118 | 93 |
| Oil Sands Mining | (71) | (107) |
| Segment income (loss) | (277) | (281) |
| Items not allocated to segments, net of income taxes | (492) | (1,130) |
| Net income (loss) | $(769) | $(1,411) |

North America E&P segment loss increased $57 million after-tax in the first nine months of 2016 from the comparable 2015 period primarily due to lower price realizations and net sales volumes, which were partially offset by the impact of lower net sales volumes to DD&A, production costs and taxes other than income; and lower exploration expenses.

International E&P segment income increased $25 million after-tax in the first nine months of 2016 from the comparable 2015 period primarily due to sales volume mix changes in E.G. and U.K. which resulted in a decrease in production costs as a result of lower U.K. sales volumes, which was partially offset by lower price realizations.

Oil Sands Mining segment loss decreased $36 million after-tax in the first nine months of 2016 from the comparable 2015 period primarily due to higher sales volumes and lower production expenses, which were partially offset by lower price realizations.

Critical Accounting Estimates

There have been no material changes or developments in the evaluation of the accounting estimates and the underlying assumptions or methodologies pertaining to our Critical Accounting Estimates disclosed in our Form 10-K for the year ended December 31, 2015, except as discussed below.

Fair Value Estimates - 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. We performed our annual impairment test in April 2016 and concluded no impairment was required. While the fair value of our International E&P reporting unit exceeded book value, subsequent commodity price and/or common stock declines may cause us to reassess our goodwill for impairment, and could result in non-cash impairment charges in the future.

Fair Value Estimates - Impairment Assessments of Long-Lived Assets

The continued decline of commodity prices resulted in a downward revision of our long-term commodity price assumptions which triggered an assessment of certain long-lived assets related to oil and gas producing properties for impairment as of September 30, 2016. We estimated the fair values using an income approach and concluded that impairments of $47 million were required (See Notes 13 & 14). Changes in management's forecast assumptions may cause us to reassess our long-lived assets for impairment and could result in non-cash impairment charges in the future.

Income Tax Estimates - Deferred Tax Assets

In connection with our assessment of the realizability of our deferred tax assets, 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. This assessment requires analysis of all available positive and negative evidence, including losses in recent years as well as forecasts of future income, assessment of future business assumptions and applicable tax planning strategies. We expect to be in a cumulative loss position in 2017 which constitutes significant objective negative evidence. However, we have concluded that our long-term commodity price forecast, proved reserves and available tax planning strategies provide sufficient positive evidence to support the net deferred tax assets recorded as of September 30, 2016. 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 forecast) are revised such that they reduce estimates of future taxable income during the carryforward period.

Estimated Quantities of Net Reserves

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

| | Unweighted 11-month 2016 Average | Unweighted 12-month 2015 Average |
|---|---|---|
| WTI Crude oil | $41.99 | $50.28 |
| Henry Hub natural gas | 2.41 | 2.59 |
| Brent crude oil | 42.67 | 54.25 |
| Natural gas liquids | 15.58 | 17.32 |

Any significant future price change could have a material effect on the quantity and present value of our proved reserves. If commodity pricing were to significantly decrease, a material volume of our proved reserves could become uneconomic and would have to be reclassified to non-proved reserves or resource category. In this scenario, our OSM proved reserves represent the largest risk to be reclassified to non-proved reserve or resource category.

Accounting Standards Not Yet Adopted

See Note 2 to the consolidated financial statements.

Cash Flows

The following table presents sources and uses of cash and cash equivalents:

| (In millions) | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|
| Sources of cash and cash equivalents | | |
| Operating activities | $618 | $1,213 |
| Disposals of assets | 837 | 105 |
| Borrowings | — | 1,996 |
| Common stock issuance | 1,236 | — |
| Maturities of short-term investment | — | 225 |
| Other | 49 | 97 |
| Total sources of cash and cash equivalents | $2,740 | $3,636 |
| Uses of cash and cash equivalents | | |
| Cash additions to property, plant and equipment | $(983) | $(2,948) |
| Acquisitions, net of cash acquired | (902) | — |
| Purchases of short-term investments | — | (925) |
| Debt issuance costs | — | (19) |
| Debt repayments | (1) | (34) |
| Dividends paid | (119) | (427) |
| Other | (3) | (1) |
| Total uses of cash and cash equivalents | $(2,008) | $(4,354) |

Cash flows generated from operating activities in the first nine months of 2016 were lower as the downturn in the commodity cycle continues to impact price realizations and negatively impact our cash flows from operating activities. In the first nine months of 2016, consolidated average oil and NGL price realizations were down by approximately 20% and consolidated net sales volumes declined by 11% as compared to the prior year.

Proceeds from disposals of assets in 2016 are primarily from the sale of our Wyoming upstream and midstream assets, as well as the sale of other non-core assets in West Texas and New Mexico; see Note 6 to the consolidated financial statements for further information concerning dispositions. Common stock issuance reflects net proceeds received in March 2016 from our public sale of common stock. See Liquidity and Capital Resources below for additional information.

On August 1, 2016, we closed the Oklahoma STACK acquisition for a purchase price of $902 million, net of cash acquired; see Note 5 to the consolidated financial statements for further information concerning acquisitions.

Additions to property, plant and equipment were lower in the first nine months of 2016 consistent with a reduced Capital Program as compared to the prior year. The following table shows capital expenditures by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows.

| (In millions) | Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|
| North America E&P | $684 | $2,048 |
| International E&P | 62 | 275 |
| Oil Sands Mining | 28 | 26 |
| Corporate | 11 | 26 |
| Total capital expenditures | 785 | 2,375 |
| Decrease in capital expenditure accrual | 198 | 573 |
| Total use of cash and cash equivalents for property, plant and equipment | $983 | $2,948 |

The Board of Directors approved a $0.05 per share dividend for the first and second quarters of 2016, which were paid in the second and third quarters of 2016, respectively. See Capital Requirements below for additional information about the third quarter dividend.

Liquidity and Capital Resources

In March 2016, we issued 166,750,000 shares of our common stock, par value $1 per share, at a price of $7.65 per share, excluding underwriting discounts and commissions, for net proceeds of $1,236 million. The proceeds were used to strengthen our balance sheet and for general corporate purposes, including funding a portion of our Capital Program.

Also in March 2016, we increased our $3 billion unsecured Credit Facility by $300 million to a total of $3.3 billion. Fees on the unused commitment of each lender, as well as the borrowing options under the Credit Facility, remain unaffected by the increase.

Our main sources of liquidity are cash and cash equivalents, sales of non-core assets, internally generated cash flow from operations, capital market transactions, and our $3.3 billion Credit Facility. Our working capital requirements are supported by these sources and we may draw on our $3.3 billion 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.

Due to decreases in crude oil and U.S. natural gas prices, credit rating agencies reviewed companies in the industry earlier this year, including us. During the first quarter of 2016, our corporate credit rating was downgraded by: Standard & Poor's Ratings Services to BBB- (stable) from BBB (stable); by Fitch Ratings to BBB (negative) from BBB+ (stable); and by Moody's Investor Services, Inc. to Ba1 (negative) from Baa1 (stable). On October 11, 2016 Moody’s Investor Services, Inc. subsequently revised their outlook of our corporate credit rating to stable from negative. Any further rating downgrades could increase our future cost of financing or limit our ability to access capital, and result in additional collateral requirements. See Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2015 for a discussion of how a further downgrade in our credit ratings could affect us.

The June 23, 2016 referendum by British voters to exit the European Union (“Brexit”) provided uncertainty and potential volatility around European currencies and resulted in a decline in the value of the British pound, as compared to the U.S. dollar and other currencies. Volatility in exchange rates may continue in the short term as the U.K. negotiates its exit from the European Union. A weaker British pound compared to the U.S. dollar during a reporting period causes local currency results of our U.K. operations to be translated into fewer U.S. dollars. For our U.K. operations, a majority of our revenues are tied to global crude oil prices which are denominated in U.S. dollars while a significant portion of our operating and capital costs are denominated in British pounds. In addition, our U.K. operations have an asset retirement obligation, which represents a future cash commitment. In the longer term, any impact from Brexit on our U.K. operations will depend, in part, on the outcome of tariff, trade, regulatory, and other negotiations.

Capital Resources

Credit Arrangements and Borrowings

At September 30, 2016, we had no borrowings against our revolving credit facility.

At September 30, 2016, we had $7.3 billion in long-term debt outstanding, with our next debt maturity in the amount of $682 million due in the fourth quarter of 2017.

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 a "well-known seasoned issuer" for purposes of SEC rules, have the ability to issue and sell an indeterminate amount of various types of equity and debt securities.

Asset Disposals

We have announced or closed \$1.5 billion of non-core asset sales since August 2015. Recently, we announced the sale of certain non-operated CO2 and waterflood assets in West Texas and New Mexico for proceeds of \$235 million, before closing adjustments. The sale subsequently closed late October.

During the third quarter 2016, we sold certain non-operated assets primarily in West Texas and New Mexico to multiple purchasers for combined proceeds of approximately \$67 million, subject to certain adjustments.

During the second quarter 2016, we announced the sale of our Wyoming upstream and midstream assets for proceeds of \$870 million, before closing adjustments, of which approximately \$690 million was received. The remaining asset sales are subject to the receipt of certain tribal consents and are expected to close before year-end. The proceeds for the remaining asset sales were deposited into an escrow account by the buyer.

In March and April 2016, we entered into separate agreements to sell our 10% working interest in the outside-operated Shenandoah discovery in the Gulf of Mexico, operated natural gas assets in the Piceance basin in Colorado and certain undeveloped acreage in West Texas for a combined total of approximately $80 million in proceeds, before closing adjustments. We closed on certain of the asset sales during the nine months ended September 30, 2016. The remaining asset sales are expected to close by year-end.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash and cash equivalents to total debt-plus-equity-minus-cash and cash equivalents) was 22% at September 30, 2016, compared to 25% at December 31, 2015.

| (In millions) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Long-term debt due within one year | $1 | $1 |
| Long-term debt | 7,277 | 7,276 |
| Total debt | $7,278 | $7,277 |
| Cash and cash equivalents | $1,953 | $1,221 |
| Equity | $18,922 | $18,553 |
| Calculation: | | |
| Total debt | $7,278 | $7,277 |
| Minus cash and cash equivalents | 1,953 | 1,221 |
| Total debt minus cash, cash equivalents | $5,325 | $6,056 |
| Total debt | $7,278 | $7,277 |
| Plus equity | 18,922 | 18,553 |
| Minus cash and cash equivalents | 1,953 | 1,221 |
| Total debt plus equity minus cash, cash equivalents | $24,247 | $24,609 |
| Cash-adjusted debt-to-capital ratio | 22 % | 25 % |

Capital Requirements

On October 26, 2016, our Board of Directors approved a dividend of $0.05 per share for the third quarter of 2016 payable December 12, 2016 to stockholders of record at the close of business on November 16, 2016.

As of September 30, 2016, we plan to make contributions of up to $16 million to our funded pension plans during the remainder of 2016.

Contractual Cash Obligations

As of September 30, 2016, there are no material changes to our consolidated cash obligations to make future payments under existing contracts, as disclosed in our 2015 Annual Report on Form 10-K.

Environmental Matters and Other Contingencies

In July 2015, we received a request for information from the EPA under Section 114 of the Clean Air Act regarding several tank batteries used in our Bakken operations. Beginning in the second quarter of 2016, we have been in settlement discussions with the State of North Dakota’s Department of Health regarding potential noncompliance with the Clean Air Act, North Dakota Century Code Air Pollution Control provisions, and implementing regulations. We anticipate executing a settlement agreement to close these discussions in the fourth quarter of 2016. We anticipate that resolution of this matter will result in civil or administrative penalties in excess of $100,000 and will require us to undertake corrective actions which may increase our development and/or operating costs. We do not believe that any penalties or corrective action expenditures that may result from this matter will have a material adverse effect on our financial position, results of operation or cash flows.

Forward-Looking Statements

This report 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 (the "Exchange Act"). All statements other than statements of historical fact, including without limitation statements regarding our future performance, business strategy, reserve estimates, asset quality, production guidance, drilling plans, capital plans, cost and expense estimates, assets acquisitions and sales, future financial position, and other plans and objectives for future operations, are forward-looking statements. Words such as “anticipate,” “believe,” "could," “estimate,” “expect,” “forecast,” "guidance," "intend," "may," “plan,” “project,” “seek,” “should,” "target," "will," “would” or similar words may be used to identify forward-looking statements; however, the absence of these words does not mean that the statements are not forward-looking. While we believe our assumptions concerning future events are reasonable, a number of factors could cause results to differ materially from those projected, including, but not limited to:

- conditions in the oil and gas industry, including supply/demand levels and the resulting impact on price;
- changes in expected reserve or production levels;
- changes in economic conditions in the jurisdictions in which we operate, including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions;
- capital available for exploration and development;
- risks related to our hedging activities;
- our level of success in integrating acquisitions;
- well production timing;
- drilling and operating risks;
- availability of materials and labor;
- difficulty in obtaining necessary approvals and permits;
- non-performance by third parties of contractual obligations;
- unforeseen hazards such as weather conditions;
- political conditions and developments, including political instability, acts of war or terrorist acts, and the governmental or military response thereto;
- cyber-attacks;
- changes in safety, health, environmental, tax and other regulations;
- other geological, operating and economic considerations; and
- the risk factors, forward-looking statements and challenges and uncertainties described in our 2015 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other filings with the SEC.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to revise or update any forward-looking statements as a result of new information, future events or otherwise.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For a detailed discussion of our risk management strategies and our derivative instruments, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our 2015 Annual Report on Form 10-K. Notes 14 and 15 to the consolidated financial statements include additional disclosures regarding our open derivative positions, including underlying notional quantities, how they are reported in our consolidated financial statements and how their fair values are measured.

Commodity Price Risk During the first nine months of 2016, we entered into crude oil and natural gas derivatives, indexed to NYMEX WTI and Henry Hub, related to a portion of our forecasted North America E&P sales. The following tables provide a summary of open positions as of September 30, 2016 and the weighted average price for those contracts:

Crude Oil

| | 2016 | 2017 | | | |
|---|---|---|---|---|---|
| | Fourth Quarter | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| Three-Way Collars [(a)] | | | | | |
| Volume (Bbls/day) | 47,000 | 30,000 | 30,000 | — | — |
| Price per Bbl: | | | | | |
| Ceiling | $55.37 | $58.19 | $58.19 | — | — |
| Floor | $50.23 | $49.33 | $49.33 | — | — |
| Sold put | $40.96 | $42.67 | $42.67 | — | — |
| Sold call options [(b)] | | | | | |
| Volume (Bbls/day) | 10,000 | 35,000 | 35,000 | 35,000 | 35,000 |
| Price per Bbl | $72.39 | $61.91 | $61.91 | $61.91 | $61.91 |
| Two-way Collars | | | | | |
| Volume (Bbls/day) | 10,000 | — | — | — | — |
| Price per Bbl: | | | | | |
| Ceiling | $50.00 | — | — | — | — |
| Floor | $41.55 | — | — | — | — |

(a) Subsequent to September 30, 2016, we entered into 10,000 Bbls/day of three-way collars for January - June 2017 with a ceiling price of $58.27, a floor price of $49.50, and a sold put price of $42.50.

(b) Call options settle monthly.

Natural Gas

| | 2016 | 2017 | | | |
|---|---|---|---|---|---|
| | Fourth Quarter | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
| Three-Way Collars [(a)] | | | | | |
| Volume (MMBtu/day) | 20,000 | 60,000 | 60,000 | 60,000 | 60,000 |
| Price per MMBtu | | | | | |
| Ceiling | $2.93 | $3.46 | $3.46 | $3.46 | $3.46 |
| Floor | $2.50 | $2.84 | $2.84 | $2.84 | $2.84 |
| Sold put | $2.00 | $2.35 | $2.35 | $2.35 | $2.35 |

(a) On our 2016 collars, the counterparty has the option to execute fixed-price swaps (swaptions) at a weighted average price of $2.93 per MMBtu indexed to NYMEX Henry Hub, which is exercisable on December 22, 2016. If counterparty exercises, the term of the fixed-price swaps would be for the calendar year 2017 and, if all such options are exercised, 20,000 MMBtu per day.

The following table provides a sensitivity analysis of the projected incremental effect on income (loss) from operations of a hypothetical 10% change in NYMEX WTI and Henry Hub prices on our open commodity derivative instruments as of September 30, 2016.

| (In millions) | Hypothetical Price Increase of 10% | Hypothetical Price Decrease of 10% |
|---|---|---|
| Crude oil derivatives | $ (59 ) | $ 46 |
| Natural gas derivatives | (6 ) | 5 |
| Total | $ (65 ) | $ 51 |

Interest Rate Risk Sensitivity analysis of the incremental effect of a hypothetical 10% decrease in interest rates on financial assets and liabilities as of September 30, 2016, is provided in the following table.

| (In millions) | Fair Value | | Incremental Change in Fair Value |
|---|---|---|---|
| Financial assets (liabilities): [a] | | | |
| Interest rate cash flow hedges | $2 | [b] | $ (11 ) |
| Interest rate fair value hedges | $8 | [b] | $ 1 |
| Long term debt, including amounts due within one year | $(7,345) | [b][c] | $ (273 ) |

(a) Fair value of cash and cash equivalents, receivables, 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.

## Item 4. 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 Exchange Act) 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 September 30, 2016.

During the third quarter of 2016, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II – OTHER INFORMATION

Item 1. Legal and Administrative Proceedings

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

In July 2015, we received a request for information from the EPA under Section 114 of the Clean Air Act regarding several tank batteries used in our Bakken operations. Beginning in the second quarter of 2016, we have been in settlement discussions with the State of North Dakota's Department of Health regarding potential noncompliance with the Clean Air Act, North Dakota Century Code Air Pollution Control provisions, and implementing regulations. We anticipate executing a settlement agreement to close these discussions in the fourth quarter of 2016. We anticipate that resolution of this matter will result in civil or administrative penalties in excess of $100,000 and will require us to undertake corrective actions which may increase our development and/or operating costs. We do not believe that any penalties or corrective action expenditures that may result from this matter will have a material adverse effect on our financial position, results of operation or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. There have been no material changes to the risk factors under Item 1A. Risk Factors in our 2015 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about repurchases by Marathon Oil of its common stock during the quarter ended September 30, 2016.

| 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 | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| 07/01/16 - 07/31/16 | 3,468 | $15.16 | — | n/a |
| 08/01/16 - 08/31/16 | 39,245 | $14.89 | — | n/a |
| 09/01/16 - 09/30/16 | 2,352 | $14.61 | — | n/a |
| Total | 45,065 | $14.89 | — | |

(a) 45,065 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Exhibit Index accompanying this Form 10-Q.

SIGNATURES

Pursuant to the requirements 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.

| | |
|---|---|
| November 3, 2016 | MARATHON OIL CORPORATION |
| | |
| By: | /s/ Gary E. Wilson |
| | Gary E. Wilson |
| | Vice President, Controller and Chief Accounting Officer |
| | (Duly Authorized Officer) |

Exhibit Index

| Exhibit Number | Exhibit Description | Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form | Exhibit | Filing Date |
|---|---|---|---|---|
| 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 February 24, 2016)* | | | |
| 3.3 | Specimen of Common Stock Certificate | 10-K | 3.3 | 2/28/2014 |
| 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 SEC upon its request | 10-K | 4.1 | 2/28/2014 |
| 10.1 | Marathon Oil Corporation 2016 Incentive Compensation Plan | 14A | App. A | 4/07/2016 |
| 10.2 | Separation Agreement with John R. Sult | 8-K | 10.1 | 9/23/2016 |
| 10.3 | Consulting Services Agreement with John R. Sult | 8-K | 10.2 | 9/23/2016 |
| 10.4 | Separation Agreement with Lance W. Robertson | 8-K | 10.3 | 9/23/2016 |
| 10.5 | Form of Restricted Stock Award Agreement for Section 16 Reporting Officers granted under the Marathon Oil Corporation 2016 Incentive Compensation Plan | 8-K/A | 10.1 | 9/30/2016 |
| 12.1 | Computation of Ratio of Earnings to Fixed Charges* | | | |
| 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* | | | |
| 101.INS | XBRL Instance Document* | | | |
| 101.SCH | XBRL Taxonomy Extension Schema* | | | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase* | | | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase* | | | |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase* | | | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase* | | | |
| * | Filed herewith. | | | |