MARATHON OIL CORP
Form 10-Q
August 04, 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
For the Quarterly Period Ended June 30, 2016

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
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 847,258,512 shares of Marathon Oil Corporation common stock outstanding as of July 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)

(In millions, except per share data)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Revenues and other income:				
Sales and other operating revenues, including related party	$870	$1,307	$1,584	$2,587
Marketing revenues	89	183	147	387
Income from equity method investments	37	26	51	62
Net gain (loss) on disposal of assets	294	—	234	1
Other income	12	15	16	26
Total revenues and other income	1,302	1,531	2,032	3,063
Costs and expenses:				
Production	350	450	678	894
Marketing, including purchases from related parties	88	182	146	387
Other operating	95	81	204	188
Exploration	189	111	213	201
Depreciation, depletion and amortization	561	751	1,170	1,572
Impairments	—	44	1	44
Taxes other than income	39	78	87	145
General and administrative	132	168	283	339
Total costs and expenses	1,454	1,865	2,782	3,770
Income (loss) from operations	(152)	(334)	(750)	(707)
Net interest and other	(86)	(58)	(171)	(105)
Income (loss) before income taxes	(238)	(392)	(921)	(812)
Provision (benefit) for income taxes	(68)	(6)	(344)	(150)
Net income (loss)	$(170)	$(386)	$(577)	$(662)
Net income (loss) per share:				
Basic	$(0.20)	$(0.57)	$(0.73)	$(0.98)
Diluted	$(0.20)	$(0.57)	$(0.73)	$(0.98)
Dividends per share	$0.05	$0.21	$0.10	$0.42
Weighted average common shares outstanding:				
Basic	848	677	790	676
Diluted	848	677	790	676

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

(In millions)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net income (loss)	$(170)	$(386)	$(577)	$(662)
Other comprehensive income (loss)				
Postretirement and postemployment plans				
Change in actuarial loss and other	19	86	(5)	162
Income tax provision (benefit)	(7)	(30)	2	(57)
Postretirement and postemployment plans, net of tax	12	56	(3)	105
Other, net of tax	(2)	—	(2)	—
Other comprehensive income (loss)	10	56	(5)	105
Comprehensive income (loss)	$(160)	$(330)	$(582)	$(557)

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)	June 30, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$2,584	$1,221
Receivables, less reserve of $4 and $4	822	912
Inventories	272	313
Other current assets	76	144
Total current assets	3,754	2,590
Equity method investments	944	1,003
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,659 and $23,260	25,657	27,061
Goodwill	115	115
Other noncurrent assets	2,057	1,542
Total assets	$32,527	$32,311
Liabilities		
Current liabilities:		
Accounts payable	$953	$1,313
Payroll and benefits payable	114	133
Accrued taxes	85	132
Other current liabilities	229	150
Long-term debt due within one year	1	1
Total current liabilities	1,382	1,729
Long-term debt	7,280	7,276
Deferred tax liabilities	2,392	2,441
Defined benefit postretirement plan obligations	409	403
Asset retirement obligations	1,597	1,601
Deferred credits and other liabilities	314	308
Total liabilities	13,374	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 – 89 million and 93 million shares	(3,397)	(3,554)
Additional paid-in capital	7,433	6,498
Retained earnings	14,320	14,974
Accumulated other comprehensive loss	(140)	(135)
Total stockholders' equity	19,153	18,553
Total liabilities and stockholders' equity	$32,527	$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)	Six Months Ended June 30, 2016	2015
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income (loss)	$(577)	$(662)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Deferred income taxes	(392)	(185)
Depreciation, depletion and amortization	1,170	1,572
Impairments	1	44
Net (gain) loss on derivative instruments	88	17
Net cash received (paid) in settlement of derivative instruments	46	4
Pension and other postretirement benefits, net	14	14
Exploratory dry well costs and unproved property impairments	166	148
Net (gain) loss on disposal of assets	(234)	(1)
Equity method investments, net	22	37
Changes in:		
Current receivables	88	534
Inventories	30	21
Current accounts payable and accrued liabilities	(211)	(770)
All other operating, net	41	(56)
Net cash provided by operating activities	252	717
Investing activities:		
Additions to property, plant and equipment	(753)	(2,320)
Disposal of assets	758	2
Investments - return of capital	37	31
Purchases of short-term investments	—	(925)
Deposit for acquisition	(89)	—
All other investing, net	2	(1)
Net cash used in investing activities	(45)	(3,213)
Financing activities:		
Borrowings	—	1,996
Debt issuance costs	—	(19)
Debt repayments	—	(34)
Common stock issuance	1,236	—
Dividends paid	(77)	(285)
All other financing, net	—	11
Net cash provided by (used in) financing activities	1,159	1,669
Effect of exchange rate on cash and cash equivalents	(3)	1
Net increase (decrease) in cash and cash equivalents	1,363	(826)
Cash and cash equivalents at beginning of period	1,221	2,398
Cash and cash equivalents at end of period	$2,584	$1,572

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

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.

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.

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 second quarter and first six months of 2016 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Not Yet Adopted

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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. 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. While early adoption is permitted, we plan to adopt in the first quarter of 2018. We continue to evaluate certain provisions of this accounting standards update and are assessing 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 June 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 $468 million as of June 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 14 million stock options for the three and six month periods ended June 30, 2016 and 13 million stock options for the three and six month periods ended June 30, 2015 that were antidilutive.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2016	2015	2016	2015
Net income (loss)	$(170)	$(386)	$(577)	$(662)
Weighted average common shares outstanding	848	677	790	676
Weighted average common shares, diluted	848	677	790	676
Net income (loss) per share:				
Basic	$(0.20)	$(0.57)	$(0.73)	$(0.98)
Diluted	$(0.20)	$(0.57)	$(0.73)	$(0.98)

5. Acquisitions

In June 2016, we executed a purchase agreement to acquire PayRock Energy Holdings, LLC ("PayRock"), a portfolio company of EnCap Investments, which closed on August 1, 2016 for $888 million, subject to closing adjustments. PayRock has approximately 61,000 net surface acres and current production of approximately 9,000 net barrels of oil equivalent in the oil window of the Anadarko Basin STACK play in Oklahoma. In the second quarter of 2016 an $89 million deposit was paid into escrow related to the acquisition. The purchase price was paid with cash on hand. We accounted for this transaction as an asset acquisition, with the majority of the purchase price allocated to property, plant and equipment.

6. Dispositions

2016 - North America E&P Segment

During the quarter, 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 June 30, 2016 with total assets of $104 million and total liabilities of $4 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 net loss on sale of $48 million for the six months ended June 30, 2016. The remaining asset sales are 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 approximately $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 13).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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 represents income 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 June 30, 2016					
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
Sales and other operating revenues	$617	$159	$185	$ (91)	(c)	$870
Marketing revenues	53	23	13	—		89
Total revenues	670	182	198	(91)		959
Income from equity method investments	—	37	—	—		37
Net gain on disposal of assets and other income	2	7	1	296	(d)	306
Less:						
Production expenses	129	56	165	—		350
Marketing costs	52	23	13	—		88
Exploration expenses	37	4	7	141	(e)	189
Depreciation, depletion and amortization	433	68	49	11		561
Other expenses [(a)]	97	22	9	99	(f)	227
Taxes other than income	35	—	4	—		39
Net interest and other	—	—	—	86		86
Income tax benefit	(41)	(2)	(10)	(15)		(68)
Segment income (loss) / Net income (loss)	$(70)	$55	$(38)	$ (117)		$(170)
Capital expenditures [(b)]	$153	$12	$7	$ 5		$177

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Unrealized loss on commodity derivative instruments.
(d) Primarily related to partial sale of Wyoming upstream and midstream assets. (See note 6.)
(e) Impairments associated with decision to not drill remaining Gulf of Mexico undeveloped leases.
(f) Includes pension settlement loss of $31 million (See note 8).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended June 30, 2015				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$993	$211	$147	$ (44) [c]	$1,307
Marketing revenues	110	30	43	—	183
Total revenues	1,103	241	190	(44)	1,490
Income from equity method investments	—	26	—	—	26
Net gain on disposal of assets and other income	11	4	—	—	15
Less:					
Production expenses	179	64	207	—	450
Marketing costs	112	29	41	—	182
Exploration expenses	91	20	—	—	111
Depreciation, depletion and amortization	634	71	35	11	751
Impairments	—	—	—	44 [d]	44
Other expenses [a]	99	19	9	122 [e]	249
Taxes other than income	67	—	5	6	78
Net interest and other	—	—	—	58	58
Income tax provision (benefit)	(23)	27	(30)	20 [f]	(6)
Segment income (loss) / Net income (loss)	$(45)	$41	$(77)	$ (305)	$(386)
Capital expenditures [b]	$551	$99	$16	$ 12	$678

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized loss on commodity derivative instruments.
[d] Proved property impairment (See Note 13).
[e] Includes pension settlement loss of $64 million (see Note 8).
[f] Includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase (see Note 9).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
	Six Months Ended June 30, 2016					
Sales and other operating revenues	$1,110	$255	$333	$ (114)	[c]	$1,584
Marketing revenues	84	38	25	—		147
Total revenues	1,194	293	358	(114)		1,731
Income from equity method investments	—	51	—	—		51
Net gain on disposal of assets and other income	3	13	1	233	[d]	250
Less:						
Production expenses	263	109	306	—		678
Marketing costs	84	37	25	—		146
Exploration expenses	55	10	7	141	[e]	213
Depreciation, depletion and amortization	920	118	109	23		1,170
Impairments	1	—	—	—		1
Other expenses [a]	215	38	16	218	[f]	487
Taxes other than income	77	—	9	1		87
Net interest and other	—	—	—	171		171
Income tax benefit	(153)	(14)	(27)	(150)		(344)
Segment income (loss) / Net income (loss)	$(265)	$59	$(86)	$ (285)		$(577)
Capital expenditures [b]	$468	$44	$16	$ 8		$536

[a] Includes other operating expenses and general and administrative expenses.
(b)Includes accruals.
[c] Unrealized loss on commodity derivative instruments.
[d] Related to net gain on disposal of assets (see Note 6).
[e] Impairments associated with decision to not drill remaining Gulf of Mexico undeveloped leases.
[f] Includes pension settlement loss of $79 million and severance related expenses associated with workforce reductions of $8 million (see Note 8).

(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
	Six Months Ended June 30, 2015					
Sales and other operating revenues	$1,843	$393	$372	$ (21)	[c]	$2,587
Marketing revenues	288	56	43	—		387
Total revenues	2,131	449	415	(21)		2,974
Income from equity method investments	—	62	—	—		62
Net gain on disposal of assets and other income	11	14	1	1		27
Less:						
Production expenses	381	131	382	—		894
Marketing costs	292	54	41	—		387
Exploration expenses	126	75	—	—		201
Depreciation, depletion and amortization	1,317	135	97	23		1,572
Impairments	—	—	—	44	[d]	44
Other expenses [a]	216	42	18	251	[e]	527

Taxes other than income	128	—	10	7	145
Net interest and other	—	—	—	105	105
Income tax provision (benefit)	(112)	24	(36)	(26) [f]	(150)
Segment income (loss) / Net income (loss)	$(206)	$64	$(96)	$ (424)	$(662)
Capital expenditures [b]	$1,484	$245	$37	$ 14	$1,780

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

[b] Includes accruals.

[c] Unrealized loss on commodity derivative instruments.

[d] Proved property impairments (See Note 13).

[e] Includes pension settlement loss of $81 million and severance related expenses associated with workforce reductions of $43 million (see Note 8).

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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

8. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Service cost	$6	$12	$1	$ 1
Interest cost	10	13	2	2
Expected return on plan assets	(13)	(17)	—	—
Amortization:				
– prior service cost (credit)	(3)	(2)	(1)	(1)
– actuarial loss	4	7	—	—
Net settlement loss [a]	31	64	—	—
Net curtailment loss [b]	—	—	—	2
Net periodic benefit cost	$35	$77	$2	$ 4

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2016	2015	2016	2015
Service cost	$12	$24	$2	$ 2
Interest cost	21	27	5	5
Expected return on plan assets	(28)	(36)	—	—
Amortization:				
– prior service cost (credit)	(5)	(1)	(2)	(2)
– actuarial loss	7	14	—	—
Net settlement loss [a]	79	81	—	—
Net curtailment loss (gain) [b]	—	1	—	(4)
Net periodic benefit cost	$86	$110	$5	$ 1

(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.

During the first six 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 six months of 2016, we made contributions of $30 million to our funded pension plans. We expect to make additional contributions up to an estimated $34 million to our funded pension plans over the remainder of 2016. During the first six months of 2016, we made payments of $37 million and $10 million related to unfunded pension plans and other postretirement benefit plans, respectively.

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. Our effective income tax rates for the first six months of 2016 and 2015 were 37% and 18%. In Libya, considerable uncertainty remains around the timing of future production and sales levels. Reliable estimates of 2016 and 2015 Libyan annual ordinary income from our 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

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recorded as a discrete item in the first six months of 2016 and 2015. For the first six 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 36% and 15% for the first six months of 2016 and 2015. The change was driven by a shift in jurisdictional income and tax legislation enacted by the Alberta government 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. 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 June 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 third 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)	June 30, 2016	December 31, 2015
Liquid hydrocarbons, natural gas and bitumen	$31	$ 35
Supplies and other items	241	278
Inventories, at cost	$272	$ 313

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

(In millions)	June 30, 2016	December 31, 2015
North America E&P	$13,965	$ 15,226
International E&P	2,479	2,533
Oil Sands Mining	9,101	9,197
Corporate	112	105
Net property, plant and equipment	$25,657	$ 27,061

Our Libya operations continue to be impacted by civil unrest. Operations were interrupted in mid-2013 as a result of the shutdown of the Es-Sider crude oil terminal, and although temporarily re-opened during the second half of 2014, production remains shut-in. Earlier this year, an Internationally-backed Unity Government was established in Tripoli. During the second quarter, the two National Oil Companies agreed to unify and reportedly have begun preliminary discussions on re-opening the Es-Sider and other crude oil terminals which, if successful, will allow resumption of production operations at our Waha concessions. However, considerable uncertainty remains around the timing of future production and sales levels.

As of June 30, 2016, our net property, plant and equipment investment in Libya is $775 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 continue to exceed the carrying value of $775 million by a material amount. However, changes in

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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 June 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. Fair Value Measurements

Fair Values - Recurring

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

	June 30, 2016			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Commodity [(a)]	$—	$ 6	$ —	$ 6
Interest rate	—	12	—	12
Derivative instruments, assets	$—	$ 18	$ —	$ 18
Derivative instruments, liabilities				
Commodity [(a)]	$—	$ 70	$ —	$ 70
Derivative instruments, liabilities	$—	$ 70	$ —	$ 70

[(a)] Derivative instruments are recorded on a net basis in the company's balance sheet (see Note 14).

	December 31, 2015			
(In millions)	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 the company's balance sheet (see Note 14).

Commodity derivatives include three-way collars, two-way collars, call options and swaptions. 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. Interest rate swaps are measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs. See Note 14 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 and operating expenses and tax rates. The assumptions used in the income approach

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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 June 30,			
	2016		2015	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$—	$ —	$17	$ 44

	Six Months Ended June 30,			
	2016		2015	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$—	$ 1	$17	$ 44

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.

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.

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 June 30, 2016 and December 31, 2015.

	June 30, 2016		December 31, 2015	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$198	$ 206	$104	$ 118
Total financial assets	$198	$ 206	$104	$ 118
Financial liabilities				
Other current liabilities	$25	$ 24	$34	$ 33
Long-term debt, including current portion [(a)]	7,186	7,291	6,723	7,291

Deferred credits and other liabilities	121	117	97	95
Total financial liabilities	$7,332	$ 7,432	$6,854	$ 7,419

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

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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.

14. Derivatives

For further information regarding the fair value measurement of derivative instruments, see Note 13. 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.

	June 30, 2016			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$12	$ —	$ 12	Other noncurrent assets
Total Designated Hedges	$12	$ —	$ 12	

	June 30, 2016			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Not Designated as Hedges				
Commodity	$6	$ 39	$ 33	Other current liabilities
Commodity	—	31	31	Deferred credits and other liabilities
Total Not Designated as Hedges	$6	$ 70	$ 64	

	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.

	June 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	4.94	%	$600	4.73	%
March 15, 2018	$300	4.77	%	$300	4.66	%

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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 June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2016	2015	2016	2015
Derivative					
Interest rate	Net interest and other	$—	$(2)	$4	$3
Hedged Item					
Long-term debt	Net interest and other	$—	$2	$(4)	$(3)

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, call options and swaptions. 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 June 30, 2016 and the weighted average prices for those contracts:

Crude Oil

	Third Quarter	Fourth Quarter	Year Ending December 31, 2017
Three-Way Collars			
Volume (Bbls/day)	47,000	47,000	—
Price per Bbl:			
Ceiling	$55.37	$55.37	—
Floor	$50.23	$50.23	—
Sold put	$40.96	$40.96	—
Sold call options [a]			
Volume (Bbls/day)	10,000	10,000	35,000
Price per Bbl	$72.39	$72.39	$61.91
Two-way Collars			
Volume (Bbls/day)	10,000	10,000	—
Price per Bbl:			—
Ceiling	$50.00	$50.00	
Floor	$41.55	$41.55	

[a] Call options settle monthly.

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Natural Gas

	Third Quarter	Fourth Quarter	Year Ending December 31, 2017
Three-Way Collars [(a)]			
Volume (MMBtu/day)	20,000	20,000	40,000
Price per MMBtu			
Ceiling	$2.93	$2.93	$3.28
Floor	$2.50	$2.50	$2.75
Sold put	$2.00	$2.00	$2.25

(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 mark-to-market impact of these commodity derivative instruments appears in sales and other operating revenues in our consolidated statements of income for the three and six month periods ended June 30, 2016 was a net loss of $88 million and $90 million compared to a net loss of $43 million and $17 million for the same respective periods in 2015. Net cash received from settlements of commodity derivative instruments for the three and six month periods ended June 30, 2016 was $14 million and $46 million compared to $4 million for both of the respective periods in 2015.

15. Incentive Based Compensation

Stock options, restricted stock awards and restricted stock units

The following table presents a summary of activity for the first six 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	5,233,984	$7.91
Options Exercised/Stock Vested	—	—	(1,148,953)	$32.29
Canceled	(973,295)	$25.76	(557,051)	$23.20
Outstanding at June 30, 2016	13,372,124	$27.42	7,545,324	$15.23

(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 six 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.

16. Debt

Revolving Credit Facility

As of June 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 June 30, 2016, we were in compliance with this covenant with a debt-to-capitalization ratio of 28%.

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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.

17. Reclassifications Out of Accumulated Other Comprehensive Loss

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

	Three Months Ended June 30,		Six Months Ended June 30,		
(In millions)	2016	2015	2016	2015	Income Statement Line
Postretirement and postemployment plans					
Amortization of actuarial loss	$(4)	$(7)	$(7)	$(14)	General and administrative
Net settlement loss	(31)	(64)	(79)	(81)	General and administrative
Net curtailment gain (loss)	—	(2)	—	3	General and administrative
	(35)	(73)	(86)	(92)	Income (loss) from operations
	13	25	29	32	Provision (benefit) for income taxes
Total reclassifications to expense	$(22)	$(48)	$(57)	$(60)	Net income (loss)

18. 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.

19. Supplemental Cash Flow Information

	Six Months Ended June 30,	
(In millions)	2016	2015
Net cash (used in) operating activities:		
Interest paid (net of amounts capitalized)	$(177)	$(143)
Income taxes paid to taxing authorities	(61)	(165)
Noncash investing activities:		
Asset retirement cost increase	$2	$6
Asset retirement obligations assumed by buyer	83	—

20. 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.

21. Subsequent Event

During the third quarter 2016, we executed an agreement to terminate our Gulf of Mexico deepwater drilling rig contract. As a result, we expect to recognize a termination payment of $113 million in other operating expense in that quarter.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Executive Overview
Outlook
Operations
Market Conditions
Results of Operations
Critical Accounting Estimates
Cash Flows and Liquidity

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 $33 billion at June 30, 2016.

Our significant strategic actions and financial results include the following:

- Strengthened balance sheet
  - At the end of the second quarter of 2016, we had $5.9 billion of liquidity, comprised of $2.6 billion in cash and an undrawn $3.3 billion revolving credit facility
  - Cash-adjusted debt-to-capital ratio of 20% at June 30, 2016, as compared with 25% at December 31, 2015
- Focused on cost reductions
  - Production expenses per boe in the second quarter of 2016, as compared to the same period last year improved in the North America E&P segment by 13% to $6.28 per boe and in the International E&P segment by 22% to $5.09 per boe
  - 2016 Capital Program reduced by $100 million to $1.3 billion
  - Eagle Ford completed well costs down 30% to $4.2 million versus the same quarter last year
- Simplifying and concentrating portfolio
  - Closed on the PayRock acquisition of STACK assets in Oklahoma for $888 million, funded with cash on hand
  - Entered into agreements for over $1 billion of transaction value related to non-core asset sales; already received over $800 million in proceeds through August 1, 2016
- Major Project updates
  - Alba B3 compression project in E.G., designed to maintain the production plateau two additional years and extend field life up to eight years, was completed within budget and on schedule with first gas in July
  - Outside-operated Gunflint development project in the Gulf of Mexico achieved first oil in July
- Financial results
  - Cash provided by operating activities of $252 million for the first six months of 2016, despite average crude oil and condensate price realizations of $35.27 per bbl.
  - Net loss per share of $0.20 in the second quarter of 2016 as compared to net loss per share of $0.57 in the same period last year. Included in the second quarter 2016 net loss are:
    - Unrealized losses from our commodity derivative instruments totaling $91 million, pre-tax
    - Net gains on disposal of non-core assets totaling $294 million, pre-tax
    - Non-cash impairments totaling $141 million, pre-tax, as a result of our decision not to drill any of our remaining Gulf of Mexico leases

Outlook

Commodity prices are the most significant factor impacting our revenues, profitability, operating cash flows and the amount of capital available to reinvest into our business. Our focus continues on the strengthening of the balance sheet, the simplification and concentration of our portfolio and cost reductions which during the second quarter of 2016 included a reduction to our Capital Program of $100 million to $1.3 billion for the year.

Exploration Update

In September 2015, we announced our intention to scale back our conventional exploration program, with future exploration investment focused on fulfilling our existing commitments in the Gulf of Mexico and Gabon. In second quarter of 2016, we made the decision to not drill our remaining Gulf of Mexico undeveloped leases. As a result, we recorded a non-cash impairment of $141 million in the second quarter of 2016. Additionally, during the third quarter 2016, we executed an agreement to terminate our Gulf of Mexico deepwater drilling rig contract. As a result, we expect to recognize a termination payment of $113 million in other operating expense in that quarter.

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.

	Three Months Ended June 30,			Six Months Ended June 30,		
Net Sales Volumes	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
North America E&P (mboed)	224	274	(18)%	232	278	(17)%
International E&P (mboed)	120	108	11%	108	112	(4)%
Oil Sands Mining (mbbld) [a]	49	29	69%	54	44	23%
Total (mboed)	393	411	(4)%	394	434	(9)%

[a] Includes blendstocks

North America E&P

Net sales volumes in the segment were lower in the second quarter and first six months of 2016 primarily as a result of decreased drilling and completion activity resulting in fewer wells brought to sales as well as 17 mboed relating to dispositions of certain non-core assets (Gulf of Mexico and East Texas, North Louisiana and Wilburton, Oklahoma) during the second half of 2015. The following tables provide details regarding net sales volumes, sales mix and operational drilling activity for our significant operations within this segment:

	Three Months Ended June 30,			Six Months Ended June 30,		
Net Sales Volumes	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Equivalent Barrels (mboed)						
Eagle Ford	109	135	(19)%	114	141	(19)%
Oklahoma Resource Basins	27	24	13%	27	24	13%
Bakken	53	61	(13)%	55	59	(7)%
Other North America [a]	35	54	(35)%	36	54	(33)%
Total North America E&P	224	274	(18)%	232	278	(17)%

[a] Includes 17 mboed of Gulf of Mexico and other conventional onshore U.S. production, which was disposed of during the sale of non-core assets in the second half of 2015.

	Three Months Ended June 30, 2016		
Sales Mix - U.S. Resource Plays	Crude oil and condensate	Natural gas liquids	Natural gas
Eagle Ford	56%	21%	23%
Oklahoma Resource Basins	21%	29%	50%
Bakken	83%	9%	8%

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Gross Operated				
Eagle Ford:				
Wells drilled to total depth	40	59	98	147
Wells brought to sales	30	52	80	143
Oklahoma Resource Basins:				
Wells drilled to total depth	6	5	11	13
Wells brought to sales	5	3	8	8
Bakken:				
Wells drilled to total depth	—	5	3	25
Wells brought to sales	4	22	10	46

- Eagle Ford – Of the 30 gross operated wells brought to sales during the second quarter of 2016, 19 were Lower Eagle Ford, 3 were Upper Eagle Ford and 8 were Austin Chalk. Production decreases were due to lower completion activity with fewer gross operated wells brought to sales and reduced contribution from 2015 high-density pads drilled at tighter well spacing. Our average time to drill an Eagle Ford well in the second quarter 2016, spud-to-total depth, was 8 days, a decrease from 11 days in the same quarter last year as efficiency gains in drilling continued. Wells were drilled at an average rate of 2,400 feet per day.
- Oklahoma Resource Basins – Of the 5 gross operated wells brought to sales in the second quarter of 2016, 3 were in the SCOOP Woodford; 2 were in the STACK Meramec and all were extended laterals. We also participated in 16 outside-operated wells during the second quarter of 2016, 10 of which were in the SCOOP and 6 were in the STACK.

We closed on the Payrock acquisition in the STACK play in Oklahoma on August 1, 2016 and continue to operate one drilling rig on the acreage with plans to add another rig late in the third quarter. This will bring the total rig count in Oklahoma to 4.

- Bakken – Of the 4 gross operated wells brought to sales in the second quarter of 2016, 2 were in the Middle Bakken formation and 2 in the Three Forks formation, all with higher intensity completions. We do not currently have an active drilling rig in the Bakken.
- Other North America – Net sales volumes declined in the second quarter of 2016 primarily due to the 2015 sales of the non-core assets in the Gulf of Mexico, East Texas, North Louisiana and Wilburton, Oklahoma. On June 30, we closed the sale of certain of our Wyoming upstream and midstream assets. Net sales volumes for all of our Wyoming assets were approximately 16 mboed for the second quarter and first half of 2016.

The Gunflint field, located in Mississippi Canyon block 948 in the Gulf of Mexico, achieved first production in July 2016. Full production is expected to reach at least 20 mboed gross with oil representing approximately 75% of the volumes produced. We hold an 18% non-operated working interest in the Gunflint field.

International E&P

Net sales volumes in the segment were higher in the second quarter of 2016 primarily as a result of planned turnaround and maintenance activities at the Alba field and E.G. LNG facilities in the second quarter of 2015. The following table provides details regarding net sales volumes for our significant operations within this segment.

	Three Months Ended June 30,			Six Months Ended June 30,		
Net Sales Volumes	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Equivalent Barrels (mboed)						
Equatorial Guinea	101	89	13%	93	93	—%
United Kingdom[(a)]	19	19	—%	15	19	(21)%
Total International E&P	120	108	11%	108	112	(4)%
Equity Method Investees						
LNG (mtd)	5,797	4,991	16%	5,060	5,629	(10)%
Methanol (mtd)	1,303	673	94%	1,292	778	66%
Condensate & LPG (boed)	11,306	8,586	32%	10,757	10,892	(1)%

(a) Includes natural gas acquired for injection and subsequent resale of 5 mmcfd and 7 mmcfd for the second quarters of 2016 and 2015, and 5 mmcfd and 9 mmcfd for the first six months of 2016 and 2015.

- Equatorial Guinea – Second quarter 2016 net sales were higher compared to the same quarter of 2015 due to lower planned turnaround and maintenance activities at the Alba field and E.G. LNG facilities. The Alba field compression project achieved first gas in July, which 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 six months of 2016 were lower due to 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 shut-in.
- Libya – Due to continued civil unrest, there were no liftings during the quarter, or any period presented. Earlier this year, an Internationally-backed Unity Government was established in Tripoli. During the second quarter, the two National Oil Companies agreed to unify and reportedly have begun preliminary discussions on re-opening the Es-Sider and other crude oil terminals which, if successful, will allow resumption of production operations at our Waha concessions. However, considerable uncertainty remains around the timing of future production and sales levels.

Oil Sands Mining

Our net synthetic crude oil sales volumes were 49 mbbld and 54 mbbld in the second quarter and first six months of 2016 compared to 29 mbbld and 44 mbbld in the same periods of 2015. Sales volumes increased in comparison to second quarter and first six months of 2015 which were adversely affected due to planned turnarounds at the base upgrader and Muskeg River Mine and unplanned downtime at the expansion upgrader. These sales volume increases were partially offset by a brief suspension of operations at both the Muskeg River and Jackpine mines in May 2016 in order to support emergency response efforts related to the Fort McMurray area wildfires in addition to the completion of planned maintenance activities at the Jackpine Mine and expansion upgrader that began in the first quarter 2016. Neither of the mines sustained any damage as a result of the wildfires. 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 lower in the second quarter and first six 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 second quarter and first six months of 2016 and 2015.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Decrease	2016	2015	Increase (Decrease)
Average Price Realizations [(a)]						
Crude Oil and Condensate (per bbl) [(b)]	$40.77	$52.63	(23)%	$34.21	$47.11	(27)%
Natural Gas Liquids (per bbl)	14.84	14.77	—%	11.43	14.60	(22)%
Total Liquid Hydrocarbons (per bbl)	35.07	45.96	(24)%	29.32	41.37	(29)%
Natural Gas (per mcf)	1.96	2.76	(29)%	1.99	2.88	(31)%
Benchmarks						
WTI crude oil (per bbl)	$45.64	$57.95	(21)%	$39.78	$53.34	(25)%
LLS crude oil (per bbl)	47.35	62.94	(25)%	41.49	57.97	(28)%
Mont Belvieu NGLs (per bbl) [(c)]	17.52	17.65	(1)%	15.78	18.02	(12)%
Henry Hub natural gas (per mmbtu)	1.95	2.64	(26)%	2.02	2.81	(28)%

(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 $0.12 per bbl and $0.06 per bbl for the second quarter 2016 and 2015, and $0.91 per bbl and $0.14 per bbl for the first six months of 2016 and 2015. Inclusion of realized gains on natural gas derivative instruments would have increased average realizations by $0.02 per mcf and $0.01 per mcf for the second quarter and first six months of 2016.

(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 second quarter and first six months of 2016 and 2015.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Average Price Realizations						
Crude Oil and Condensate (per bbl)	$42.21	$56.70	(26)%	$37.56	$52.92	(29)%
Natural Gas Liquids (per bbl)	2.65	3.10	(15)%	2.45	3.29	(26)%
Liquid Hydrocarbons (per bbl)	32.11	44.70	(28)%	28.11	41.06	(32)%
Natural Gas (per mcf)	0.53	0.78	(32)%	0.56	0.78	(28)%
Benchmark						
Brent (Europe) crude oil (per bbl) [(a)]	$45.52	$61.69	(26%)	$39.61	$57.81	(31)%

(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 second quarter and first six months of 2016 and 2015.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Decrease	2016	2015	Increase (Decrease)
Average Price Realizations						
Synthetic Crude Oil (per bbl)	$40.88	$52.46	(22%)	$32.94	$44.33	(26 %)
Benchmarks						
WTI crude oil (per bbl)	$45.64	$57.95	(21%)	$39.78	$53.34	(25 %)
WCS crude oil (per bbl)[a]	32.29	46.35	(30%)	25.75	40.13	(36 %)

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

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Results of Operations

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

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

(In millions)	Three Months Ended June 30, 2016	2015
Sales and other operating revenues, including related party		
North America E&P	$617	$993
International E&P	159	211
Oil Sands Mining	185	147
Segment sales and other operating revenues, including related party	$961	$1,351
Unrealized (loss) gain on commodity derivative instruments	(91)	(44)
Sales and other operating revenues, including related party	$870	$1,307

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 June 30, 2015	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended June 30, 2016
North America E&P Price-Volume Analysis [(a)]				
Liquid hydrocarbons	$ 893	$(172)	$ (170)	$ 551
Natural gas	90	(22)	(13)	55
Realized gain on commodity derivative instruments	1	2		3
Other sales	9			8
Total	$ 993			$ 617
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 172	$(50)	$ 7	$ 129
Natural gas	28	(10)	4	22
Other sales	11			8
Total	$ 211			$ 159
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$ 137	$(51)	$ 95	$ 181
Other sales	10			4
Total	$ 147			$ 185

(a) Three months ended June 30, 2016 includes a net sales volume reduction of 17 mboed related to dispositions in the Gulf of Mexico and other conventional onshore U.S. production.

Marketing revenues decreased $94 million in the second quarter of 2016 from the comparable prior-year period. Marketing activities include the purchase of commodities from third parties for resale and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Since the volume of marketing activity is based on market dynamics, it can fluctuate from period to period. The decreases are related primarily to lower marketed volumes in North America E&P and OSM, which were further compounded by a lower commodity price environment.

Income from equity method investments increased $11 million in the second quarter of 2016 from the comparable 2015 period. The increase is primarily due to an increase in net sales volumes as 2015 volumes were lower because of planned turnaround and maintenance activities at the Alba field and E.G. LNG facilities.

Net gain on disposal of assets in the second quarter of 2016 was primarily related to the sale of our Wyoming upstream and midstream assets and West Texas acreage. See Note 6 to the consolidated financial statements for

information about dispositions.
Production expenses decreased $100 million. North America E&P declined $50 million primarily due to lower operational, maintenance and labor costs, coupled with the disposition of our producing assets in the Gulf of Mexico and East Texas, North Louisiana and Wilburton, Oklahoma gas assets. International E&P declined $8 million primarily as a result of lower project and labor costs in the U.K. and 2015 also includes costs arising from planned flowline maintenance at the outside operated Foinaven field; these declines were partially offset by increased costs resulting from higher net sales volumes. OSM

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decreased $42 million primarily due to lower turnaround costs and continued cost management, specifically staffing and contract labor.

The second 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 higher sales volumes and lower production expenses, as discussed above.

The following table provides production expense rates for each segment:

	Three Months Ended June 30,	
($ per boe)	2016	2015
Production Expense Rate		
North America E&P	$6.28	$7.19
International E&P	$5.09	$6.51
Oil Sands Mining [(a)]	$39.02	$78.24

(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.

Marketing costs decreased $94 million in the second quarter of 2016 from the comparable 2015 period, consistent with the marketing revenues changes discussed above.

Exploration expenses increased $78 million primarily as a result of our decision to not drill any of our remaining Gulf of Mexico undeveloped leases. The following table summarizes the components of exploration expenses:

	Three Months Ended June 30,	
(In millions)	2016	2015
Exploration Expenses		
Unproved property impairments	$133	$40
Dry well costs	22	41
Geological and geophysical	—	12
Other	34	18
Total exploration expenses	$189	$111

Depreciation, depletion and amortization decreased $190 million primarily as a result of production volume decreases, a higher proved reserve base in Eagle Ford in the second half of 2015 and as a result of the non-core asset dispositions in 2015. 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 North America E&P decreased primarily as a result of a higher proved reserve base in Eagle Ford in the second half of 2015. The DD&A rate for International E&P declined due to lower asset retirement costs, with cost estimates refined in the fourth quarter of 2015. 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 June 30,	
($ per boe)	2016	2015
DD&A Rate		
North America E&P	$21.16	$25.45
International E&P	$6.22	$7.17

Oil Sands Mining	$11.39	$12.87

Impairments decreased $44 million in the second quarter of 2016 as a result of the second quarter of 2015 non-cash impairment charge related to East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets in anticipation of the sale in 2015. See Note 13 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 $39 million in the second quarter of 2016. The following table summarizes the components of taxes other than income:

(In millions)	Three Months Ended June 30, 2016	2015
Production and severance	$25	$ 40
Ad valorem	5	15
Other	9	23
Total	$39	$ 78

General and administrative expenses decreased $36 million primarily due to lower pension settlement charges in the second quarter of 2016, which totaled $31 million, compared to $64 million in the prior year.
Net interest and other increased $28 million primarily due to increased interest expense associated with our June 2015 debt issuance. See Note 16 to the consolidated financial statements for discussion of the June 2015 debt issuance.
Provision (benefit) for income taxes reflects an effective tax rate of 29% in the second quarter of 2016, as compared to 2% in the second 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. 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, or other items that affect comparability also are not allocated to operating segments.
The following table reconciles segment income (loss) to net income (loss):

(In millions)	Three Months Ended June 30, 2016	2015
North America E&P	$(70)	$(45)
International E&P	55	41
Oil Sands Mining	(38)	(77)
Segment income (loss)	(53)	(81)
Items not allocated to segments, net of income taxes	(117)	(305)
Net income (loss)	$(170)	$(386)

North America E&P segment loss increased $25 million after-tax primarily due to lower price realizations and sales volumes, which was 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 $14 million after-tax primarily due to decreased exploration expenses and an increase in income from equity investments, which were partially offset by lower price realizations.
Oil Sands Mining segment loss decreased $39 million after-tax primarily due to higher sales volumes and lower production expenses, partially offset by lower price realizations and higher DD&A expense.

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

(In millions)	Six Months Ended June 30, 2016	2015
Sales and other operating revenues, including related party		
North America E&P	$1,110	$1,843
International E&P	255	393
Oil Sands Mining	333	372
Segment sales and other operating revenues, including related party	$1,698	$2,608
Unrealized loss on commodity derivative instruments	(114)	(21)
Sales and other operating revenues, including related party	$1,584	$2,587

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)	Six Months Ended June 30, 2015	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Six Months Ended June 30, 2016
North America E&P Price-Volume Analysis [a]				
Liquid hydrocarbons	$ 1,633	$(394)	$ (279)	$ 960
Natural gas	188	(51)	(24)	113
Realized gain on commodity derivative instruments	5	19		24
Other sales	17			13
Total	$ 1,843			$ 1,110
International E&P Price-Volume Analysis				
Crude oil and condensate				
Natural gas liquids				
Liquid hydrocarbons	$ 310	$(90)	$ (26)	$ 194
Natural gas	60	(17)	—	43
Other sales	23			18
Total	$ 393			$ 255
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$ 355	$(112)	$ 81	$ 324
Other sales	17			9
Total	$ 372			$ 333

[a] Six months ended June 30, 2016 includes a net sales volume reduction of 17 mboed related to dispositions in the Gulf of Mexico and other conventional onshore U.S. production.

Marketing revenues for the first six months of 2016 decreased by $240 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 decreased $11 million. The decrease is primarily due to lower net sales volumes as a result of planned downtime at E.G. as a result of the Alba field compression project which impacted our equity method plants, which was partially offset by planned turnaround and maintenance activities at the Alba field and E.G. LNG facilities in 2015. Also impacting the first six months of 2016 were lower price realizations for LPG at our Alba plant.

Net gain on disposal of assets for the first six months of 2016 was primarily related to the sale of our Wyoming upstream and midstream assets and West Texas acreage. See Note 6 to the consolidated financial statements for information about dispositions.

Production expenses for the first six months of 2016 decreased by $216 million compared to the same period of 2015. North America E&P declined $118 million due to lower operational, maintenance and labor costs, coupled with the disposition of our producing assets in the Gulf of Mexico and East Texas, North Louisiana and Wilburton, Oklahoma gas assets. International E&P declined $22 million largely due to lower operational costs in the U.K. OSM decreased $76 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 six 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 six months of 2016 primarily due to reduced maintenance and project costs in the U.K. The OSM expense rate decreased in the first six months of 2016 primarily due to higher production coupled with lower operational costs.

	Six Months Ended June 30,	
($ per boe)	2016	2015
Production Expense Rate		
North America E&P	$6.22	$7.57
International E&P	$5.53	$6.45
Oil Sands Mining [(a)]	$33.42	$50.06

(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 $241 million in the first six months of 2016 from the comparable 2015 period, consistent with the marketing revenues changes discussed above.

Exploration expenses were $12 million higher in the first six months of 2016 than in the comparable 2015 period primarily due to higher unproved property impairments, which were partially offset by lower dry well costs. Unproved property impairments were higher in 2016 primarily as a result of Gulf of Mexico leases that we decided not to drill. Dry well costs for the first six months of 2015 primarily consist of costs associated with the Sodalita West #1 well in E.G., the Key Largo well in the Gulf of Mexico, and suspended well costs related to Birchwood in-situ. The following table summarizes the components of exploration expenses:

	Six Months Ended June 30,	
(In millions)	2016	2015
Exploration Expenses		
Unproved property impairments	$144	$49
Dry well costs	22	99
Geological and geophysical	—	15
Other	47	38
Total exploration expenses	$213	$201

Depreciation, depletion and amortization ("DD&A") decreased $402 million in the first six months of 2016 from the comparable 2015 period primarily as a result of production volume decreases and a higher proved reserve base in Eagle Ford in the second half of 2015. 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 a higher proved reserve base in Eagle Ford in the second half of 2015.

($ per boe)	Six Months Ended June 30, 2016	2015
DD&A Rate		
North America E&P	$21.79	$26.16
International E&P	$5.98	$6.62
Oil Sands Mining	$11.34	$12.58

Impairments decreased $43 million in the first six months of 2016 as a result of the second quarter of 2015 non-cash impairment charge related to East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets in anticipation of the sale in 2015. See Note 13 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 $58 million in the first six months of 2016 from the comparable 2015 period. The following table summarizes the components of taxes other than income:

(In millions)	Six Months Ended June 30, 2016	2015
Production and severance	$44	$74
Ad valorem	19	31
Other	24	40
Total	$87	$145

General and administrative expenses decreased $56 million in the first six months of 2016 compared to the same period in 2015. This decrease was primarily due to cost savings realized from the 2015 workforce reductions and corresponding severance expenses.

Provision (benefit) for income taxes reflect effective tax rates of 37% in the first six months of 2016, as compared to 18% 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. 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, or other items that affect comparability also are not allocated to operating segments.

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

(In millions)	Six Months Ended June 30, 2016	2015
North America E&P	$(265)	$(206)
International E&P	59	64
Oil Sands Mining	(86)	(96)
Segment income (loss)	(292)	(238)
Items not allocated to segments, net of income taxes	(285)	(424)
Net income (loss)	$(577)	$(662)

North America E&P segment loss increased $59 million after-tax in the first six months of 2016 from the comparable 2015 period primarily due to lower price realizations and sales volumes, which was 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 decreased $5 million after-tax in the first six months of 2016 from the comparable 2015 period primarily due to lower liquid hydrocarbon price realizations. These declines were partially offset by lower exploration, production and DD&A expenses.
Oil Sands Mining segment loss decreased $10 million after-tax in the first six months of 2016 from the comparable 2015 period primarily due to higher sales volumes and lower production expenses, partially offset by lower price realizations and higher DD&A expense.

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.

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 eight months of 2016:

	Unweighted 8-month 2016 Average	Unweighted 12-month 2015 Average
WTI Crude oil	$40.48	$50.28
Henry Hub natural gas	2.24	2.59
Brent crude oil	41.08	54.25
Natural gas liquids	14.92	17.32

Any significant future price change could have a material effect on the quantity and present value of our proved reserves. To the extent that commodity prices decrease during the remainder of 2016, a portion of our proved reserves could be deemed uneconomic and no longer classified as proved. This could impact both proved developed producing reserves as well as proved undeveloped reserves. Assuming lower commodity pricing in the remaining 4-months of 2016, a material volume of our proved reserves could become uneconomic and would have to be reclassified to non-proved reserve or resource category. In this scenario, our OSM proved reserves represent the largest risk to be reclassified to non-proved reserve or resource category. However, any impact of lower SEC pricing will likely be partially offset by continued cost reduction efforts. Also, any volumes reclassified to non-proved reserves could return to proved reserves as commodity prices improve. In the event the OSM proved reserves are reclassified to non-proved reserves or resource, their classification will have no impact on future plans for production.

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)	Six Months Ended June 30, 2016	2015
Sources of cash and cash equivalents		
Operating activities	$252	$717
Disposals of assets	758	2
Borrowings	—	1,996
Common stock issuance	1,236	—
Other	39	43
Total sources of cash and cash equivalents	$2,285	$2,758
Uses of cash and cash equivalents		
Cash additions to property, plant and equipment	$(753)	$(2,320)
Deposit for acquisition	(89)	—
Purchases of short-term investments	—	(925)
Debt issuance costs	—	(19)
Debt repayments	—	(34)
Dividends paid	(77)	(285)
Other	(3)	(1)
Total uses of cash and cash equivalents	$(922)	$(3,584)

Cash flows generated from operating activities in the first six months of 2016 were lower as the downturn in the commodity cycle continued. This continued downward pressure on price realizations, coupled with the lower net sales volumes, continues to negatively impact our cash flows from operating activities. In the first six months of 2016, consolidated average oil and NGL price realizations were down by approximately 27% and consolidated net sales volumes declined by 9% as compared to the prior year.

Proceeds from disposals of assets are primarily from the sale of our Wyoming upstream and midstream assets; 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.

Additions to property, plant and equipment are our most significant use of cash and cash equivalents and were lower in the first half 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 (the table excludes an $89 million deposit paid into escrow related to the acquisition of PayRock assets - see Note 5 to the consolidated financial statements for further information related to this acquisition):

(In millions)	Six Months Ended June 30, 2016	2015
North America E&P	$468	$1,484
International E&P	44	245
Oil Sands Mining	16	37
Corporate	8	14
Total capital expenditures	536	1,780
Decrease in capital expenditure accrual	217	540
Total use of cash and cash equivalents for property, plant and equipment	$753	$2,320

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

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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). 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 June 30, 2016, we had no borrowings against our revolving credit facility.

At June 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

During the quarter, 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. 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 six months ended June 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 20% at June 30, 2016, compared to 25% at December 31, 2015.

	June 30,	December 31,
(In millions)	2016	2015
Long-term debt due within one year	$1	$1
Long-term debt	7,280	7,276
Total debt	$7,281	$7,277
Cash and cash equivalents	$2,584	$1,221
Equity	$19,153	$18,553
Calculation:		
Total debt	$7,281	$7,277
Minus cash and cash equivalents	2,584	1,221
Total debt minus cash, cash equivalents	$4,697	$6,056
Total debt	$7,281	$7,277
Plus equity	19,153	18,553
Minus cash and cash equivalents	2,584	1,221
Total debt plus equity minus cash, cash equivalents	$23,850	$24,609
Cash-adjusted debt-to-capital ratio	20 %	25 %

Capital Requirements

We closed on our purchase agreement of PayRock for $888 million, as discussed in Note 5 to the consolidated financial statements. We expect our Capital Program for full-year 2016 to be $1.3 billion, or $100 million lower than the original budget, which includes the increased activity from the PayRock acquisition.

On July 27, 2016, our Board of Directors approved a dividend of $0.05 per share for the second quarter of 2016 payable September 12, 2016 to stockholders of record at the close of business on August 17, 2016.

As of June 30, 2016, we plan to make contributions of up to $34 million to our funded pension plans during the remainder of 2016.

Contractual Cash Obligations

As of June 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, except for the agreement we entered into to acquire PayRock as described above, which was paid with cash on hand.

During the third quarter we executed an agreement to terminate our Gulf of Mexico deepwater drilling rig contract, as a result we expect to make a termination payment of $113 million during the third quarter of 2016.

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. To date, no federal or state enforcement action has been commenced in connection with this matter. We anticipate that resolution of this matter will result in civil or administrative penalties of an undetermined amount and 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 13 and 14 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 six 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 June 30, 2016 and the weighted average price for those contracts:

Crude Oil

			Year Ending December 31,
	Third Quarter	Fourth Quarter	2017
Three-Way Collars			
Volume (Bbls/day)	47,000	47,000	—
Price per Bbl:			
Ceiling	$55.37	$55.37	—
Floor	$50.23	$50.23	—
Sold put	$40.96	$40.96	—
Sold call options [(a)]			
Volume (Bbls/day)	10,000	10,000	35,000
Price per Bbl	$72.39	$72.39	$61.91
Two-way Collars			
Volume (Bbls/day)	10,000	10,000	—
Price per Bbl:			—
Ceiling	$50.00	$50.00	
Floor	$41.55	$41.55	

(a) Call options settle monthly.

Natural Gas

			Year Ending December 31,
	Third Quarter	Fourth Quarter	2017
Three-Way Collars [(a)]			
Volume (MMBtu/day)	20,000	20,000	40,000
Price per MMBtu			
Ceiling	$2.93	$2.93	$3.28
Floor	$2.50	$2.50	$2.75
Sold put	$2.00	$2.00	$2.25

(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 June 30, 2016.

(In millions)	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Crude oil derivatives	$ (32)	$ 73
Natural gas derivatives	(5)	5
Total	$ (37)	$ 78

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

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities): [(a)]		
Interest rate swap agreements	$ 12 [(b)]	$ 1
Long term debt, including amounts due within one year	$ (7,186) [(b)(c)]	$ (287)

(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 June 30, 2016.

During the second 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. To date, no federal or state enforcement action has been commenced in connection with this matter. We anticipate that resolution of this matter will result in civil or administrative penalties of an undetermined amount and 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 June 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
04/01/16 - 04/30/16	103,922	$10.97	—	n/a
05/01/16 - 05/31/16	141,243	13.56	—	n/a
06/01/16 - 06/30/16	486	13.00	—	n/a
Total	245,651	$12.46	—	

(a) 245,651 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.

August 4, 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
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.			