MARATHON OIL CORP
Form 10-Q
August 06, 2015

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, 2015
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 (State or other jurisdiction of incorporation or organization)	25-0996816 (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 677,184,913 shares of Marathon Oil Corporation common stock outstanding as of July 31, 2015.

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).

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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, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Revenues and other income:				
Sales and other operating revenues, including related party	$1,307	$2,270	$2,587	$4,419
Marketing revenues	183	618	387	1,159
Income from equity method investments	26	120	62	257
Net gain (loss) on disposal of assets	—	(87)	1	(85)
Other income	15	20	26	40
Total revenues and other income	1,531	2,941	3,063	5,790
Costs and expenses:				
Production	450	562	894	1,104
Marketing, including purchases from related parties	182	614	387	1,156
Other operating	81	101	188	204
Exploration	111	145	201	218
Depreciation, depletion and amortization	751	680	1,572	1,323
Impairments	44	4	44	21
Taxes other than income	78	109	145	204
General and administrative	168	139	339	326
Total costs and expenses	1,865	2,354	3,770	4,556
Income (loss) from operations	(334)	587	(707)	1,234
Net interest and other	(58)	(76)	(105)	(125)
Income (loss) from continuing operations before income taxes	(392)	511	(812)	1,109
Provision (benefit) for income taxes	(6)	151	(150)	351
Income (loss) from continuing operations	(386)	360	(662)	758
Discontinued operations	—	180	—	931
Net income (loss)	$(386)	$540	$(662)	$1,689
Per basic share:				
Income (loss) from continuing operations	$(0.57)	$0.53	$(0.98)	$1.11
Discontinued operations	$—	$0.27	$—	$1.36
Net income (loss)	$(0.57)	$0.80	$(0.98)	$2.47
Per diluted share:				
Income (loss) from continuing operations	$(0.57)	$0.53	$(0.98)	$1.10
Discontinued operations	$—	$0.27	$—	$1.36
Net income (loss)	$(0.57)	$0.80	$(0.98)	$2.46
Dividends per share	$0.21	$0.19	$0.42	$0.38
Weighted average common shares outstanding:				
Basic	677	676	676	684
Diluted	677	679	676	688

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Net income (loss)	$(386)	$540	$(662)	$1,689
Other comprehensive income (loss)				
Postretirement and postemployment plans				
Change in actuarial loss and other	86	(13)	162	(43)
Income tax benefit (provision)	(30)	5	(57)	15
Postretirement and postemployment plans, net of tax	56	(8)	105	(28)
Comprehensive income (loss)	$(330)	$532	$(557)	$1,661

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

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MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	June 30, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$1,572	$2,398
Short-term investments	925	—
Receivables, less reserve of $4 and $3	1,195	1,729
Inventories	336	357
Other current assets	102	109
Total current assets	4,130	4,593
Equity method investments	1,045	1,113
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $23,395 and $21,884	29,121	29,040
Goodwill	459	459
Other noncurrent assets	1,015	806
Total assets	$35,770	$36,011
Liabilities		
Current liabilities:		
Accounts payable	$1,507	$2,545
Payroll and benefits payable	119	191
Accrued taxes	156	285
Other current liabilities	235	290
Long-term debt due within one year	1,035	1,068
Total current liabilities	3,052	4,379
Long-term debt	7,321	5,323
Deferred tax liabilities	2,531	2,486
Defined benefit postretirement plan obligations	438	598
Asset retirement obligations	1,963	1,917
Deferred credits and other liabilities	247	288
Total liabilities	15,552	14,991
Commitments and contingencies		
Stockholders' Equity		
Preferred stock – no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Securities exchangeable into common stock – no shares issued or outstanding (no par value, 29 million shares authorized)	—	—
Held in treasury, at cost – 93 million and 95 million shares	(3,555)	(3,642)
Additional paid-in capital	6,484	6,531
Retained earnings	16,691	17,638
Accumulated other comprehensive loss	(172)	(277)
Total stockholders' equity	20,218	21,020
Total liabilities and stockholders' equity	$35,770	$36,011

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, 2015	2014
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income (loss)	$(662)	$1,689
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Discontinued operations	—	(931)
Deferred income taxes	(185)	173
Depreciation, depletion and amortization	1,572	1,323
Impairments	44	21
Pension and other postretirement benefits, net	14	26
Exploratory dry well costs and unproved property impairments	148	156
Net (gain) loss on disposal of assets	(1)	85
Equity method investments, net	37	(10)
Changes in:		
Current receivables	534	(266)
Inventories	21	(58)
Current accounts payable and accrued liabilities	(770)	(31)
All other operating, net	(35)	(59)
Net cash provided by continuing operations	717	2,118
Net cash provided by discontinued operations	—	440
Net cash provided by operating activities	717	2,558
Investing activities:		
Additions to property, plant and equipment	(2,320)	(2,230)
Disposal of assets	2	2,232
Investments - return of capital	31	27
Purchases of short-term investments	(925)	—
Investing activities of discontinued operations	—	(233)
All other investing, net	(1)	—
Net cash used in investing activities	(3,213)	(204)
Financing activities:		
Commercial paper, net	—	(135)
Borrowings	1,996	—
Debt issuance costs	(19)	—
Debt repayments	(34)	(34)
Purchases of common stock	—	(1,000)
Dividends paid	(285)	(260)
All other financing, net	11	86
Net cash provided by (used in) financing activities	1,669	(1,343)
Effect of exchange rate on cash and cash equivalents:		
Continuing operations	1	—
Discontinued operations	—	(10)
Cash held for sale	—	(96)
Net increase (decrease) in cash and cash equivalents	(826)	905
Cash and cash equivalents at beginning of period	2,398	264

Cash and cash equivalents at end of period	$1,572	$1,169

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

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

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

As a result of the sale of our Angola assets and our Norway business in 2014, both are reflected as discontinued operations. The disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations, unless otherwise noted.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation 2014 Annual Report on Form 10-K. The results of operations for the second quarter and first six months of 2015 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Not Yet 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 will be applied on a retrospective basis. Early adoption is permitted. This standard only modifies disclosure requirements; as such, there will be no impact on our consolidated results of operations, financial position or cash flows.

In April 2015, the FASB issued an update that requires debt issuance costs to be presented in the balance sheet as a direct reduction from the associated debt liability. This standard is effective for us in the first quarter of 2016 and will be applied on a retrospective basis. Early adoption is permitted, including in interim periods. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2015, the FASB issued an amendment to the guidance for determining whether an entity is a variable interest entity ("VIE"). The standard does not add or remove any of the five characteristics that determine if an entity is a VIE. However, it does change the manner in which a reporting entity assesses one of the characteristics. In particular, when decision-making over the entity’s most significant activities has been outsourced, the standard changes how a reporting entity assesses if the equity holders at risk lack decision making rights. This standard is effective for us in the first quarter of 2016 and early adoption is permitted, including in interim periods. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

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

In May 2014, 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 also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively, and improves guidance for multiple-element arrangements. This standard is effective for us in the first quarter of 2018 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is permitted with an effective date no earlier than first quarter of 2017. 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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

3. Variable Interest Entity

The owners of the Athabasca Oil Sands Project ("AOSP"), in which we hold a 20% undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership (“Corridor Pipeline”) to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton, Alberta, Canada. Costs under this contract are accrued and recorded on a monthly basis, with current liabilities of $2 million recorded at June 30, 2015 and $3 million at December 31, 2014. 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 $508 million as of June 30, 2015. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month’s activity, which is substantially less than the maximum exposure over the contract term.

4. Income (Loss) per Common Share

Basic income (loss) per share is based on the weighted average number of common shares outstanding. Diluted income (loss) per share assumes exercise of stock options, provided the effect is not antidilutive. The per share calculations below exclude 13 million and 5 million stock options for the second quarters of 2015 and 2014 and 13 million and 4 million stock options for the first six months of 2015 and 2014 that were antidilutive.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2015	2014	2015	2014
Income (loss) from continuing operations	$(386)	$360	$(662)	$758
Discontinued operations	—	180	—	931
Net income (loss)	$(386)	$540	$(662)	$1,689
Weighted average common shares outstanding	677	676	676	684
Effect of dilutive securities	—	3	—	4
Weighted average common shares, diluted	677	679	676	688
Per basic share:				
Income (loss) from continuing operations	$(0.57)	$0.53	$(0.98)	$1.11
Discontinued operations	$—	$0.27	$—	$1.36
Net income (loss)	$(0.57)	$0.80	$(0.98)	$2.47
Per diluted share:				
Income (loss) from continuing operations	$(0.57)	$0.53	$(0.98)	$1.10
Discontinued operations	$—	$0.27	$—	$1.36
Net income (loss)	$(0.57)	$0.80	$(0.98)	$2.46

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

5. Dispositions
2015 - North America E&P Segment
In July 2015, we entered into an agreement to sell our East Texas/North Louisiana and Wilburton, Oklahoma natural gas assets for expected proceeds of $102 million, excluding closing adjustments. We expect the transaction to close during the third quarter of 2015.
2014 - North America E&P Segment
In June 2014, we closed the sale of non-core acreage located in the far northwest portion of Williston Basin for proceeds of $90 million. A pretax loss of $91 million was recorded in the second quarter of 2014.
2014 - International E&P Segment
In the second quarter of 2014, we entered into an agreement to sell our Norway business, including the operated Alvheim floating production, storage and offloading vessel, 10 operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea. The transaction closed during the fourth quarter of 2014.
Our Norway business was reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for 2014. Select amounts reported in discontinued operations follow:

	Three Months Ended June 30,	Six Months Ended June 30,
(In millions)	2014	2014
Revenues applicable to discontinued operations	$693	$1,373
Pretax income from discontinued operations	$598	$1,130
After-tax income from discontinued operations [(a)]	$180	$322

[(a)] Includes a tax benefit of $26 million related to a decrease in the valuation allowance on U.S. foreign tax credits from the Norway operations.

In the first quarter of 2014, we closed the sales of our non-operated 10% working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion and recorded a $576 million after-tax gain on sale. Included in the after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.
Our Angola operations are reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for the prior period. Select amounts reported in discontinued operations follow:

	Six Months Ended June 30,
(In millions)	2014
Revenues applicable to discontinued operations	$58
Pretax income from discontinued operations, before gain	$51
Pretax gain on disposition of discontinued operations	$470
After-tax income from discontinued operations	$609

6. Segment Information
We are a global energy company with operations in North America, Europe and Africa. Each of our three reportable operating segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

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

gas ("LNG") and methanol, in Equatorial Guinea ("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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations excluding certain items not allocated to segments, net of income taxes attributable to the operating segments. Our corporate and operations support general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Gains or losses on dispositions, certain impairments, change in tax expense associated with a tax rate change, unrealized gains or losses on crude oil derivative instruments, or other items that affect comparability also are not allocated to operating segments.
As discussed in Note 5, as a result of the sale of our Angola assets and our Norway business in 2014, both are reflected as discontinued operations and excluded from the International E&P segment for 2014.

	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) /Loss from continuing operations	$(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 crude oil derivative instruments.
[d] Proved property impairment (See Note 12).
[e] Includes pension settlement loss of $64 million (see Note 7).
[f] Includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase (see Note 8).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended June 30, 2014				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$1,540	$347	$383	$—	$2,270
Marketing revenues	540	61	17	—	618
Total revenues	2,080	408	400	—	2,888
Income from equity method investments	—	120	—	—	120
Net gain (loss) on disposal of assets and other income	15	15	1	(98) [c]	(67)
Less:					
Production expenses	217	99	246	—	562
Marketing costs	537	60	17	—	614
Exploration expenses	82	63	—	—	145
Depreciation, depletion and amortization	550	75	45	10	680
Impairments	4	—	—	—	4
Other expenses [a]	126	34	13	67 [d]	240
Taxes other than income	102	—	6	1	109
Net interest and other	—	—	—	76	76
Income tax provision (benefit)	175	52	19	(95)	151
Segment income/Income from continuing operations	$302	$160	$55	$(157)	$360
Capital expenditures [b]	$1,102	$115	$55	$10	$1,282

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Primarily related to the sale of non-core acreage (see Note 5).
[d] Includes pension settlement loss of $8 million (see Note 7).

	Six 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	$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) /Loss from continuing operations	$(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 crude oil derivative instruments.
(d) Proved property impairment (See Note 12).
(e) Includes $43 million of severance related expenses associated with a workforce reduction and a pension settlement loss of $81 million (see Note 7).
(f) Includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase (see Note 8).

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30, 2014				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$2,932	$727	$760	$—	$4,419
Marketing revenues	980	131	48	—	1,159
Total revenues	3,912	858	808	—	5,578
Income from equity method investments	—	257	—	—	257
Net gain (loss) on disposal of assets and other income	18	32	3	(98) [c]	(45)
Less:					
Production expenses	428	199	477	—	1,104
Marketing costs	977	131	48	—	1,156
Exploration expenses	139	79	—	—	218
Depreciation, depletion and amortization	1,065	146	90	22	1,323
Impairments	21	—	—	—	21
Other expenses [a]	236	72	26	196 [d]	530
Taxes other than income	192	—	11	1	204
Net interest and other	—	—	—	125	125
Income tax provision (benefit)	328	139	40	(156)	351
Segment income /Income from continuing operations	$544	$381	$119	$(286)	$758
Capital expenditures [b]	$1,969	$220	$123	$13	$2,325

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Primarily related to the sale of non-core acreage (see Note 5).
[d] Includes pension settlement loss of $71 million (see Note 7).

7. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost (credit):

	Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2015	2014	2015	2014
Service cost	$12	$11	$1	$1
Interest cost	13	15	2	3
Expected return on plan assets	(17)	(14)	—	—
Amortization:				
– prior service cost (credit)	(2)	2	(1)	(1)
– actuarial loss	7	10	—	—
Net settlement loss [a]	64	8	—	—
Net curtailment loss [b]	—	—	2	—
Net periodic benefit cost	$77	$32	$4	$3

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2015	2014	2015	2014
Service cost	24	23	2	2
Interest cost	27	31	5	6
Expected return on plan assets	(36)	(32)	—	—
Amortization:				
– prior service cost (credit)	(1)	3	(2)	(2)
– actuarial loss	14	16	—	—
Net settlement loss[a]	81	71	—	—
Net curtailment loss (gain) [b]	1	—	(4)	—
Net periodic benefit cost	$110	$112	$1	$6

(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 the workforce reduction, which reduced the future expected years of service for employees participating in the plans.

During the first six months of 2015, we recorded the effects of a workforce reduction and a pension plan amendment. The pension plan amendment freezes the final average pay used to calculate the formula benefit and is effective July 6, 2015. Additionally, during the first six months of 2015 and 2014, we recorded the effects of partial 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 (credit).

During the first six months of 2015, we made contributions of $46 million to our funded pension plans. We expect to make additional contributions up to an estimated $42 million to our funded pension plans over the remainder of 2015. During the first six months of 2015, we made payments of $42 million and $8 million related to unfunded pension plans and other postretirement benefit plans, respectively.

8. Income Taxes

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 (benefits) and the sum of the amounts allocated to segments is reported in the “Not Allocated to Segments” column of the tables in Note 6.

Our effective income tax rates on continuing operations for the first six months of 2015 and 2014 were 18% and 32%. The tax provision (benefit) applicable to Libyan ordinary income (loss) was recorded as a discrete item in the first six months of 2015 and 2014. Excluding Libya, the effective tax rates on continuing operations, would be 15% and 34% for the first six months of 2015 and 2014. In Libya, uncertainty remains around the timing of future production and sales levels. Reliable estimates of 2015 and 2014 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, for the first six months of 2015 and 2014, estimated annual effective tax rates were calculated excluding Libya and applied to consolidated ordinary income (loss).

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

In the second quarter of 2015, we reviewed our operations and concluded that we do not have the same level of capital needs outside the U.S. as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings of approximately $1 billion associated with our Canadian operations to be permanently reinvested outside the

U.S. As such, none of Marathon Oil's foreign earnings remain permanently reinvested abroad. We anticipate foreign tax credits associated with these Canadian earnings would be sufficient to offset any incremental U.S. tax liabilities, and therefore, no additional net deferred taxes have been recorded in the second quarter of 2015.

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9. Short-term Investments

As of June 30, 2015, our short-term investments are comprised of bank time deposits with original maturities of greater than three months and remaining maturities of less than twelve months. The maturity dates range from September 2015 to October 2015. These short-term investments are classified as held-to-maturity investments, which are recorded at amortized cost. The carrying values of our short-term investments approximate fair value.

10. Inventories

Inventories of liquid hydrocarbons, natural gas and bitumen are carried at the lower of cost or market value. Materials and supplies are valued at weighted average cost and reviewed for obsolescence or impairment when market conditions indicate.

(In millions)	June 30, 2015	December 31, 2014
Liquid hydrocarbons, natural gas and bitumen	$50	$58
Supplies and other items	286	299
Inventories, at cost	$336	$357

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

(In millions)	June 30, 2015	December 31, 2014
North America E&P	$16,757	$16,717
International E&P	2,848	2,741
Oil Sands Mining	9,401	9,455
Corporate	115	127
Net property, plant and equipment	$29,121	$29,040

Our Libya operations continue to be impacted by civil unrest and, in December 2014, Libya's National Oil Corporation once again declared force majeure at the Es Sider oil terminal, as disruptions from civil unrest continue. Considerable uncertainty remains around the timing of future production and sales levels.

As of June 30, 2015, our net property, plant and equipment investment in Libya is $775 million, and total proved reserves (unaudited) in Libya as of December 31, 2014 are 243 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 continues to exceed the carrying value of $775 million by a material amount.

Exploratory well costs capitalized greater than one year after completion of drilling were $88 million and $126 million as of June 30, 2015 and December 31, 2014. This $38 million net decrease was associated with our Canadian in-situ assets at Birchwood. After further evaluation of the estimated recoverable resources and our development plans, we withdrew our regulatory application for the proposed steam assisted gravity drainage ("SAGD") demonstration project.

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12. 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, 2015 and December 31, 2014 by fair value hierarchy level.

	June 30, 2015			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Commodity [(a)]	$—	$5	$—	$5
Interest rate	—	11	—	11
Derivative instruments, assets	$—	$16	$—	$16
Derivative instruments, liabilities				
Commodity [(a)]	$—	$26	$—	$26
Derivative instruments, liabilities	$—	$26	$—	$26

(a) Derivative instruments are recorded on a net basis in the company's balance sheet (see Note 13).

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

Commodity derivatives include three-way collars, swaptions, extendable three-way collars and call options. These instruments are measured at fair value using either the Black-Scholes Model or Black Model. Inputs to both models include prices, interest rates, and implied volatility. The inputs to these models are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Interest rate swaps are measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs.

See Note 13 for additional discussion of the types of derivative instruments we use.

Fair Values - Nonrecurring

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

	Three Months Ended June 30,			
	2015		2014	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$17	$44	$—	$4

	Six Months Ended June 30,			
	2015		2014	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$17	$44	$—	$21

Commodity prices began declining in the second half of 2014 and remain substantially lower through 2015 as compared to the first six months of 2014. As this period of sustained reduced commodity prices continues, it could result in non-cash impairment charges related to long-lived assets in future periods.

All long-lived assets held for use that were impaired in the first six months of 2015 and 2014 were held by our North America E&P segment.

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In July 2015, we entered into an agreement to sell our East Texas/North Louisiana and Wilburton, Oklahoma natural gas assets. We expect the transaction to close during the third quarter of 2015. 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. The fair values were measured using a probability weighted income approach based on both the anticipated sales price and a held-for-use model. The held-for-use model contained internal estimates of future production levels, prices and discount rate. All such inputs were classified as Level 3.

The Ozona development in the Gulf of Mexico ceased producing in 2013, at which time those long-lived assets were fully impaired. In the first and second quarters of 2014, we recorded additional impairments of $17 million and $4 million as a result of estimated abandonment cost revisions. The fair value was measured using an income approach based upon forecasted future abandonment costs, which are Level 3 inputs.

Fair Values – Financial Instruments

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

The following table summarizes financial instruments, excluding receivables, short-term investments, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at June 30, 2015 and December 31, 2014.

	June 30, 2015		December 31, 2014	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$134	$133	$132	$129
Total financial assets	134	133	132	129
Financial liabilities				
Other current liabilities	13	13	13	13
Long-term debt, including current portion [a]	8,720	8,324	6,887	6,360
Deferred credits and other liabilities	73	67	69	68
Total financial liabilities	$8,806	$8,404	$6,969	$6,441

[a] Excludes capital leases.

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

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

13. Derivatives

For further information regarding the fair value measurement of derivative instruments, see Note 12. 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 as of June 30, 2015 and December 31, 2014.

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	June 30, 2015			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$11	$—	$11	Other noncurrent assets
Total	$11	$—	$11	

	June 30, 2015			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Not Designated as Hedges				
Commodity	$5	$17	$12	Other current liabilities
Commodity	—	9	9	Other noncurrent liabilities
Total	$5	$26	$21	

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

Derivatives Designated as Fair Value Hedges

The following table presents, by maturity date, information about our interest rate swap agreements as of June 30, 2015 and December 31, 2014, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

	June 30, 2015		December 31, 2014	
Maturity Dates	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate
October 1, 2017	$600	4.67 %	$600	4.64 %
March 15, 2018	$300	4.52 %	$300	4.49 %

The pretax effects of derivative instruments designated as hedges of fair value in our consolidated statements of income are summarized in the table below. The foreign currency forwards were used to hedge the current Norwegian tax liability of our Norway business that was sold in the fourth quarter of 2014. Those instruments outstanding were transferred to the purchaser of the Norway business upon closing of the sale. There is no ineffectiveness related to the fair value hedges.

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2015	2014	2015	2014
Derivative					
Interest rate	Net interest and other	$(2)	$4	$3	$3
Foreign currency	Discontinued operations	$—	$(14)	$—	$(11)
Hedged Item					
Long-term debt	Net interest and other	$2	$(4)	$(3)	$(3)
Accrued taxes	Discontinued operations	$—	$14	$—	$11

Derivatives not Designated as Hedges

During the first six months of 2015, we entered into multiple crude oil derivatives indexed to New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI"), related to a portion of our forecasted North America E&P sales through December 2016. These commodity derivatives primarily consist of call options and three way-collars which consist of a sold call (ceiling), a purchased put (floor) and a sold put. The ceiling price is the maximum we will receive for the contract crude oil volumes, the floor is the minimum price we will receive, unless the market price falls below the sold put strike price.

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In this case, we receive the NYMEX WTI price plus the difference between the floor and the sold put price. These commodity derivatives were not designated as hedges and are shown in the table below:

Financial Instrument	Weighted Average Price	Barrels per day	Remaining Term
Three-Way Collars			
Ceiling	$70.34	35,000	July- December 2015 [(a)]
Floor	$55.57		
Sold put	$41.29		
Ceiling	$71.84	12,000	January- December 2016
Floor	$60.48		
Sold put	$50.00		
Ceiling	$73.13	2,000	January- June 2016 [(b)]
Floor	$65.00		
Sold put	$50.00		
Call Options	$72.39	10,000	January- December 2016 [(c)]

(a) Counterparties have the option to execute fixed-price swaps (swaptions) at a weighted average price of $71.67 per barrel indexed to NYMEX WTI, which is exercisable on October 30, 2015. If counterparties exercise, the term of the fixed price swaps would be for calendar year 2016 and, if all such are exercised, 25,000 barrels per day.

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

(c) Call options settle monthly.

The impact of these crude oil derivative instruments appears in sales and other operating revenues in our consolidated statements of income and was a net loss of $43 million and $17 million in the second quarter and first six months of 2015. There were no crude oil derivative instruments in the first six months of 2014.

On June 1, 2015, we entered into Treasury rate locks, which expired on the same day, to hedge against timing differences as it related to our Notes offering (see Note 15). Following the execution of the Treasury locks, corresponding interest rates increased during the day of June 1. As a result, the settlement of the Treasury rate locks resulted in a gain of $6 million, which was recognized in net interest and other in our consolidated statements of income.

14. Incentive Based Compensation

Stock option and restricted stock awards

The following table presents a summary of stock option and restricted stock award activity for the first six months of 2015:

	Stock Options			Restricted Stock		
	Number of Shares		Weighted Average Exercise Price	Awards		Weighted Average Grant Date Fair Value
Outstanding at December 31, 2014	13,427,836		$29.68	3,448,353		$34.04
Granted	724,082	(a)	$29.06	2,668,357		$30.53
Options Exercised/Stock Vested	(480,458	)	$16.47	(921,404	)	$34.29
Canceled	(455,855	)	$34.48	(491,739	)	$33.70
Outstanding at June 30, 2015	13,215,605		$29.97	4,703,567		$32.04

(a) The weighted average grant date fair value of stock option awards granted was $6.84 per share.

Stock-based performance unit awards

During the first six months of 2015, we granted 382,335 stock-based performance units to certain officers. The grant date fair value per unit was $31.77.

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15. Debt
Revolving Credit Facility As of June 30, 2015, we had no borrowings against our revolving credit facility (as amended, the "Credit Facility"), as described below.
In May 2015, we amended our $2.5 billion unsecured Credit Facility to increase the facility size by $500 million to a total of $3 billion and extend the maturity date by an additional year such that the Credit Facility now matures in May 2020. The amendment additionally provides us the ability to request two one-year extensions to the maturity date and an option to increase the commitment amount by up to an additional $500 million, subject to the consent of any increasing lenders. The sub-facilities for swing-line loans and letters of credit remain unchanged allowing up to an aggregate amount of $100 million and $500 million, respectively. Fees on the unused commitment of each lender, as well as the borrowing options under the Credit Facility, remain unchanged.
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, 2015, we were in compliance with this covenant with a debt-to-capitalization ratio of 29%.
Debt Issuance On June 10, 2015, we issued $2 billion aggregate principal amount of unsecured senior notes which consist of the following series:
•$600 million of 2.70% senior notes due June 1, 2020
•$900 million of 3.85% senior notes due June 1, 2025
•$500 million of 5.20% senior notes due June 1, 2045
Interest on each series of senior notes is payable semi-annually beginning December 1, 2015. We will use the aggregate net proceeds to repay our $1 billion 0.90% senior notes due 2015, which mature on November 1, 2015, and for general corporate purposes. We may redeem some or all of the senior notes at any time at the applicable redemption price, plus accrued interest, if any. As of June 30, 2015, we were in compliance with the covenants under the indenture governing the senior notes.
16. Reclassifications Out of Accumulated Other Comprehensive Income (Loss)
The following table presents a summary of amounts reclassified from accumulated other comprehensive income (loss) to income (loss) from continuing operations in their entirety:

	Three Months Ended June 30,		Six Months Ended June 30,		
(In millions)	2015	2014	2015	2014	Income Statement Line
Postretirement and postemployment plans					
Amortization of actuarial loss	$(7)	$(10)	$(14)	$(16)	General and administrative
Net settlement loss	(64)	(8)	(81)	(71)	General and administrative
Net curtailment gain (loss)	(2)	—	3	—	General and administrative
	(73)	(18)	(92)	(87)	Income (loss) from operations
	25	7	32	30	Benefit for income taxes
Other insignificant, net of tax	—	—	—	(1)	
Total reclassifications	$(48)	$(11)	$(60)	$(58)	Income (loss) from continuing operations

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17. Supplemental Cash Flow Information

	Six Months Ended June 30,	
(In millions)	2015	2014
Net cash used in operating activities:		
Interest paid (net of amounts capitalized)	$(143)	$(149)
Income taxes paid to taxing authorities [a]	(165)	(1,336)
Net cash provided by (used in) financing activities:		
Commercial paper, net:		
Issuances	$—	$2,285
Repayments	—	(2,420)
Commercial paper, net	$—	$(135)
Noncash investing activities, related to continuing operations:		
Asset retirement costs capitalized, net of revisions	$6	$42
Asset retirement obligations assumed by buyer	—	52
Receivable for disposal of assets	—	44

[a] The first six months of 2014 included $1.076 billion related to discontinued operations.

18. Commitments and Contingencies

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

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

We are a global energy company with operations in North America, Europe and Africa. Each of our three reportable operating segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- North America E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

As a result of the sale of our Angola assets and our Norway business in 2014, both are reflected as discontinued operations. The disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations, unless otherwise noted.

Executive Overview

Commodity prices are the most significant factor impacting our revenues, profitability, operating cash flows and their subsequent reinvestment into our business. Commodity prices began declining in the second half of 2014 and remain substantially lower through 2015 as compared to the first six months of 2014. We believe we can manage in this lower commodity price cycle through a continued focus on development in our three U.S. resource plays, operational execution, efficiency improvements, cost reductions, capital discipline and portfolio optimization, all while maintaining financial flexibility.

Our significant financial results, operating activities and strategic actions include the following:

- Increased company-wide net sales volumes from continuing operations by 4% to 411 thousand barrels of oil equivalent per day ("mboed") in the second quarter of 2015 from 394 mboed in the second quarter of 2014
  Net sales volumes from our three U.S. resource plays increased 29% to 220 mboed in the second quarter of 2015 from 170 mboed in the second quarter of 2014
- Maintained focus on cost discipline and efficiencies
  Reduced North America E&P production expenses per boe by 31% in the second quarter of 2015 compared to the same period last year
  Achieved 96% average operational availability for our operated assets in the second quarter of 2015
  Reallocated an additional $35 million of capital to Oklahoma Resource Basins to leverage higher non-operated activity and to further advance subsurface knowledge and resource delineation
- Active management of liquidity and capital structure
  $5.5 billion of liquidity at the end of the second quarter, comprised of $3.0 billion in the unused revolving credit facility and $2.5 billion in cash and short-term investments
  Cash and short-term investments-adjusted debt-to-capital ratio of 22% at June 30, 2015, as compared with 16% at December 31, 2014
  Issued $2 billion of senior notes in June 2015; plan to use $1 billion of proceeds to satisfy scheduled debt maturities in the fourth quarter of 2015 and the remainder for general corporate purposes
  Increased the capacity of the revolving credit facility to $3.0 billion from $2.5 billion while also extending the maturity date to May 2020
  Repatriated Canadian earnings in tax efficient manner, providing $250 million of cash available for use in U.S. operations
  Executed additional derivative instruments to reduce commodity price uncertainty for a portion of our forecasted North America E&P crude oil volumes
- Portfolio management activities
  We are targeting to generate at least $500 million from select non-core asset sales

Signed definitive sales agreement in July 2015 related to non-core assets for expected proceeds of $102 million, excluding closing-adjustments

Financial results

Loss from continuing operations per diluted share of $0.57 in the second quarter of 2015 as compared to income from continuing operations of $0.53 per diluted share in the same period last year

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

Operating cash flow provided by continuing operations for the first six months of 2015 was $717 million, compared to $2.1 billion in the same period last year, reflecting the lower commodity price environment

We continue to optimize our resource allocation given the current price environment. We expect our full-year 2015 capital, investment and exploration budget to be at or below $3.3 billion. We estimate our full-year North America E&P and International E&P production volumes (excluding Libya) to be 375 - 390 net mboed.

Operations

North America E&P--Production

North America E&P segment average net sales volumes in the second quarter and first six months of 2015 increased 21% and 26% compared to the second quarter and first six months of 2014. Net liquid hydrocarbon sales volumes increased 35 thousand barrels per day ("mbbld") and 47 mbbld, and net natural gas sales volumes increased 67 million cubic feet per day ("mmcfd") and 63 mmcfd in the second quarter and first six months of 2015 compared to the second quarter and first six months of 2014, reflecting continued growth from the combined U.S. resource plays.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Sales Volumes				
Crude Oil and Condensate (mbbld)				
Bakken	54	44	53	41
Eagle Ford	82	67	87	65
Oklahoma Resource Basins	5	2	5	2
Other North America [(a)]	35	38	35	36
Total Crude Oil and Condensate	176	151	180	144
Natural Gas Liquids (mbbld)				
Bakken	3	3	3	2
Eagle Ford	26	16	26	16
Oklahoma Resource Basins	6	6	6	5
Other North America[(a)]	2	2	3	4
Total Natural Gas Liquids	37	27	38	27
Total Liquid Hydrocarbons (mbbld)				
Bakken	57	47	56	43
Eagle Ford	108	83	113	81
Oklahoma Resource Basins	11	8	11	7
Other North America[(a)]	37	40	38	40
Total Liquid Hydrocarbons	213	178	218	171
Natural Gas (mmcfd)				
Bakken	22	18	20	17
Eagle Ford	164	111	167	109
Oklahoma Resource Basins	81	61	79	58
Other North America[(a)]	94	104	94	113
Total Natural Gas	361	294	360	297
Equivalent Barrels (mboed)				
Bakken	61	50	59	46
Eagle Ford	135	102	141	99
Oklahoma Resource Basins	24	18	24	17
Other North America[(a)]	54	57	54	58
Total North America E&P	274	227	278	220

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

The following table presents a summary of our operated drilling activity in the U.S. resource plays:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Gross Operated				
Eagle Ford:				
Wells drilled to total depth	59	88	147	171
Wells brought to sales	52	76	143	125
Bakken:				
Wells drilled to total depth	5	19	25	22
Wells brought to sales	22	19	46	16
Oklahoma Resource Basins:				
Wells drilled to total depth	5	6	13	11
Wells brought to sales	3	4	8	8

Eagle Ford – Average net sales volumes from Eagle Ford were 135 mboed and 141 mboed in the second quarter and first six months of 2015 compared to 102 mboed and 99 mboed in the same periods of 2014, for increases of 32% and 42%. Approximately 61% of second quarter sales was crude oil and condensate, 19% was NGLs and 20% was natural gas. Our average time to drill an Eagle Ford well in second quarter 2015, spud-to-total depth, was 11 days. Also, during the second quarter of 2015, we brought online 8 Upper Eagle Ford, 33 Lower Eagle Ford and 11 Austin Chalk gross operated wells and we completed and brought online three "stack-and-frac" pilots with wells in three horizons.

Bakken – Average net sales volumes from the Bakken shale were 61 mboed and 59 mboed in the second quarter and first six months of 2015 compared to 50 mboed and 46 mboed in the same period for 2014, for increases of 22% and 28%. Our Bakken production averaged approximately 89% crude oil, 5% NGLs and 6% natural gas. Our time to drill a Bakken well, spud-to-total depth, averaged 13 days in the second quarter of 2015.

Application of the enhanced completion design continues to provide promising results, with outperformance of historical type curves after 180 days of cumulative production. The enhanced completion design optimizes proppant loading, frac fluid volumes and stage density. Three high-density pilots (six wells per horizon) were completed through the second quarter. Also in the second quarter, our first Three Forks second bench well in the Myrmidon was completed.

Oklahoma Resource Basins – Net sales volumes from the Oklahoma Resource Basins averaged 24 mboed in both the second quarter and first six months of 2015 compared to 18 mboed and 17 mboed in the comparable 2014 periods, for increases of 33% and 41%. Our second quarter 2015 production was approximately 20% crude, 25% NGLs and 55% natural gas. Of the three gross operated wells brought to sales this quarter, two were SCOOP wells and one was a STACK Osage well. We also finished drilling five operated Smith infill pilot wells this quarter.

Additionally, we continue to leverage the benefit of participation in outside-operated wells and plan to participate in approximately 85 outside-operated wells in 2015 in the SCOOP Woodford, SCOOP Springer and STACK areas. In the first six months of 2015, we participated in four outside-operated high-density spacing pilots in the SCOOP area; three in the Woodford (80-128 acre spacing) and one in the emerging Springer shale (105-128 acre spacing) overlaying the Woodford. Two outside-operated STACK Meramec XL wells were brought to sales during the quarter.

Gulf of Mexico – Development work continues in the Gunflint field located on Mississippi Canyon Blocks 948, 949, 992 (N/2) and 993 (N/2). We expect the two-well subsea tieback to be complete in the second half of 2015. We hold an 18% non-operated working interest in the Gunflint field.

North America E&P--Exploration

Gulf of Mexico – During the second quarter, we spud the Solomon exploration prospect on Walker Ridge Block 225 and farmed down our operated working interest to 58%.

The third appraisal well on the Shenandoah prospect was spud in May 2015 and is still drilling. The well is located in Walker Ridge Block 52, in which we hold a 10% non-operated working interest.

International E&P--Production

International E&P segment average net sales volumes in the second quarter and first six months of 2015 decreased 12% and 10% compared to the second quarter and first six months of 2014, reflecting field decline and a planned turnaround in Equatorial Guinea in the second quarter of 2015, which also reduced sales to the AMPCO and LNG facilities. In addition, the AMPCO methanol facility completed a planned turnaround in first quarter 2015.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Sales Volumes				
Crude Oil and Condensate (mbbld)				
Equatorial Guinea	19	20	18	22
United Kingdom	14	13	14	13
Total Crude Oil and Condensate	33	33	32	35
Natural Gas Liquids (mbbld)				
Equatorial Guinea	9	11	10	11
United Kingdom	—	—	—	—
Total Natural Gas Liquids	9	11	10	11
Total Liquid Hydrocarbons (mbbld)				
Equatorial Guinea	28	31	28	33
United Kingdom	14	13	14	13
Total Liquid Hydrocarbons	42	44	42	46
Natural Gas (mmcfd)				
Equatorial Guinea	365	446	390	441
United Kingdom(a)	31	28	32	29
Libya	—	—	—	1
Total Natural Gas	396	474	422	471
Equivalent Barrels (mboed)				
Equatorial Guinea	89	105	93	107
United Kingdom(a)	19	18	19	18
Total International E&P (mboed)	108	123	112	125
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	4,991	6,624	5,629	6,601
Methanol (mtd)	673	980	778	1,066

(a) Includes natural gas acquired for injection and subsequent resale of 7 mmcfd and 5 mmcfd for the second quarters of 2015 and 2014, and 9 mmcfd and 6 mmcfd for the first six months of 2015 and 2014.

Equatorial Guinea – Average net sales volumes were 89 mboed and 93 mboed in the second quarter and first six months of 2015 compared to 105 mboed and 107 mboed in the same periods of 2014. Planned turnaround and maintenance activities at the Alba field and EG LNG facilities reduced production rates during the second quarter of 2015. The Alba turnaround subsequently reduced sales to our equity method investees, Alba Plant LLC, EGHoldings and AMPCO. Additionally, there was a planned turnaround at AMPCO in the first quarter of 2015.

During the second quarter of 2015, the Alba C21 development well reached total depth and completion activities are underway. To date, well performance results are consistent with pre-drill estimates.

United Kingdom – Average net sales volumes were 19 mboed for each of the second quarter and first six months of 2015, relatively flat as compared to 18 mboed in the same periods of 2014. Net sales volumes benefited from improved production as two subsea development wells at West Brae began producing during the first and second quarters of 2015. This completed the last of the planned five-well Brae infill drilling program begun in 2014. In addition, as full compression was reinstated during the second quarter of 2015 at the non-operated Foinaven field, this contributed to improved reliability.

During the third quarter of 2015, planned maintenance activities are scheduled at the East Brae and non-operated Foinaven field.

Libya – We had no sales during the first six months of 2015 as a result of continued civil unrest. In December 2014, Libya's National Oil Corporation reinstated force majeure at the Es Sider oil terminal, as disruptions from civil unrest continue. Considerable uncertainty remains around the timing of future production and sales levels.

International E&P--Exploration

Kurdistan Region of Iraq – On the Harir Block, testing was completed on the Mirawa-2 appraisal well during the second quarter of 2015. The well has been temporarily suspended as a potential future producer and the drilling rig has been de-mobilized. We hold a 45% operated working interest in the block.

Oil Sands Mining

Our net synthetic crude oil sales volumes were 29 mbbld and 44 mbbld in the second quarter and first six months of 2015 compared to 44 mbbld and 45 mbbld in the same periods of 2014. Production declined in the second quarter of 2015 primarily due to the planned turnarounds at the base upgrader and Muskeg River Mine and unplanned downtime at the expansion upgrader. Production was relatively flat in the first six months of 2015 compared to the same period in 2014 as the planned turnarounds and unplanned downtime during the second quarter of 2015 were mostly offset by higher production driven by improved mine reliability during the first quarter of 2015. We hold a 20% non-operated working interest in the AOSP.

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 significantly lower in the second quarter and first six months of 2015 as compared to the same periods in 2014; as a result, we experienced significant 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 2015 and 2014.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Average Price Realizations [a]				
Crude Oil and Condensate (per bbl) [b]				
Bakken	$51.36	$93.08	$45.84	$91.43
Eagle Ford	53.47	99.08	47.81	97.65
Oklahoma Resource Basins	51.00	101.12	48.34	98.05
Other North America [c]	52.83	93.45	47.10	91.40
Total Crude Oil and Condensate	52.63	95.95	47.11	94.30
Natural Gas Liquids (per bbl)				
Bakken	$11.63	$45.13	$7.19	$51.04
Eagle Ford	14.08	30.20	13.90	33.76
Oklahoma Resource Basins	14.45	33.04	15.83	38.21
Other North America [c]	25.65	54.13	26.03	57.65
Total Natural Gas Liquids	14.77	34.80	14.60	38.75
Total Liquid Hydrocarbons (per bbl)				
Bakken	$49.29	$90.47	$43.72	$89.16
Eagle Ford	44.05	85.36	40.01	84.78
Oklahoma Resource Basins	30.29	52.00	29.24	55.04
Other North America [c]	50.89	90.45	45.52	88.97
Total Liquid Hydrocarbons	45.96	86.43	41.37	85.65
Natural Gas (per mcf)				
Bakken	$2.62	$4.12	$2.76	$6.14
Eagle Ford	2.71	4.76	2.79	4.83
Oklahoma Resource Basins	2.64	4.57	2.63	5.01
Other North America [c]	2.98	5.65	3.29	5.35
Total Natural Gas	2.76	5.00	2.88	5.14
Benchmarks				
WTI crude oil (per bbl)[d]	$57.95	$102.99	$53.34	$100.84
Louisiana Light Sweet ("LLS") crude oil (per bbl)[e]	62.94	105.55	57.97	104.97
Mont Belvieu NGLs (per bbl) [f]	17.65	34.54	18.02	36.42
Henry Hub natural gas[g] (per mmbtu)[h]	2.64	4.67	2.81	4.80

(a) Excludes gains or losses on derivative instruments.

(b) Inclusion of realized gains on crude oil derivative instruments would have increased average crude oil price realization by $0.06 per bbl and $0.14 per bbl for the second quarter and first six months of 2015. There were no crude oil derivative instruments in 2014.

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

(d) NYMEX.

(e) Bloomberg Finance LLP: LLS St. James.

(f)

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

(g) Settlement date average.

(h) Million British thermal units.

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 for the second quarter and first six months of 2015 and 2014.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Average Price Realizations				
Crude Oil and Condensate (per bbl)				
Equatorial Guinea	$52.27	$90.91	$47.55	$90.66
United Kingdom	62.97	111.76	60.19	111.38
Total Crude Oil and Condensate	56.70	99.36	52.92	98.51
Natural Gas Liquids (per bbl)				
Equatorial Guinea [(a)]	$1.00	$1.00	$1.00	$1.00
United Kingdom	36.49	64.37	34.82	69.56
Total Natural Gas Liquids	3.10	3.02	3.29	3.64
Total Liquid Hydrocarbons (per bbl)				
Equatorial Guinea	$35.74	$59.72	$31.81	$61.12
United Kingdom	61.93	110.51	58.96	110.02
Total Liquid Hydrocarbons	44.70	75.41	41.06	75.48
Natural Gas (per mcf)				
Equatorial Guinea [(a)]	$0.24	$0.24	$0.24	$0.24
United Kingdom	6.98	8.04	7.34	9.07
Libya	—	—	—	5.45
Total Natural Gas	0.78	0.69	0.78	0.80
Benchmark				
Brent (Europe) crude oil (per bbl)[(b)]	$61.69	$109.70	$57.81	$108.93

(a) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC and Equatorial Guinea LNG Holdings Limited, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P segment.

(b) Average of monthly prices obtained from Energy Information Administration ("EIA") website.

Liquid hydrocarbons – Our United Kingdom ("U.K.") liquid hydrocarbon production is generally sold in relation to the Brent crude benchmark. Our production from Equatorial Guinea is condensate, which receives lower prices than crude oil.

NGLs in E.G. are subject to fixed-price, term contracts; therefore, our reported average NGL realized prices within the International E&P segment will not fully track market price movements.

Natural gas – Our natural gas sales from E.G. are subject to fixed-price, term contracts, making realized prices in this area less volatile; therefore, our reported average natural gas realized prices within the International E&P segment will not fully track market price movements.

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 Western Canadian Select ("WCS").

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

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The following table presents our average price realizations and the related benchmarks that impacted both our revenues and variable costs for the second quarter and first six months of 2015 and 2014.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Average Price Realizations				
Synthetic Crude Oil (per bbl)	$52.46	$94.17	$44.33	$91.27
Benchmark				
WTI crude oil (per bbl)[(a)]	$57.95	$102.99	$53.34	$100.84
WCS crude oil (per bbl)[(b)]	$46.35	$82.95	$40.13	$79.25
AECO natural gas sales index (per mmbtu)[(c)]	$2.05	$4.46	$2.07	$4.72

(a) NYMEX.
(b) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.
(c) Monthly average AECO day ahead index.

Results of Operations

Consolidated Results of Operation

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Sales and other operating revenues, including related party				
North America E&P	$993	$1,540	$1,843	$2,932
International E&P	211	347	393	727
Oil Sands Mining	147	383	372	760
Segment sales and other operating revenues, including related party	$1,351	$2,270	$2,608	$4,419
Unrealized loss on crude oil derivative instruments	(44)	—	(21)	—
Sales and other operating revenues, including related party	$1,307	$2,270	$2,587	$4,419

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.

North America E&P

(In millions)	Three Months Ended June 30, 2014	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Three Months Ended June 30, 2015
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$1,403	$(786)	$276	$893
Natural gas	133	(73)	30	90
Realized gain on crude oil derivative instruments	—	1		1
Other sales	4			9
Total	$1,540			$993

(In millions)	Six Months Ended June 30, 2014	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Six Months Ended June 30, 2015
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$2,647	$(1,748)	$734	$1,633
Natural gas	276	(147)	59	188
Realized gain on crude oil				

derivative instruments	—	5	5
Other sales	9		17
Total	$2,932		$1,843

International E&P

(In millions)	Three Months Ended June 30, 2014	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended June 30, 2015
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$305	$(118)	$(15)	$172
Natural gas	30	3	(5)	28
Other sales	12			11
Total	$347			$211

(In millions)	Six Months Ended June 30, 2014	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Six Months Ended June 30, 2015
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$634	$(261)	$(63)	$310
Natural gas	69	(2)	(7)	60
Other sales	24			23
Total	$727			$393

Oil Sands Mining

(In millions)	Three Months Ended June 30, 2014	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended June 30, 2015
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$377	$(110)	$(130)	$137
Other sales	6			10
Total	$383			$147

(In millions)	Six Months Ended June 30, 2014	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Six Months Ended June 30, 2015
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$750	$(376)	$(19)	$355
Other sales	10			17
Total	$760			$372

Marketing revenues decreased $435 million and $772 million in the second quarter and first six months of 2015 from the comparable prior-year periods. 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 decreases are 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 $94 million and $195 million in the second quarter and first six months of 2015 from the comparable 2014 period. The decrease in the second quarter of 2015 is primarily due to lower price realizations for Liquified Natural Gas ("LNG") at our LNG facility, Liquified Petroleum Gas ("LPG") at our Alba plant, and lower methanol prices at our AMPCO methanol facility, all of which are located in E.G. Also contributing to the decrease in 2015 were lower sales volumes due to the previously mentioned planned turnaround and maintenance activities at the AMPCO methanol plant, the Alba field and the LNG facility.

Production expenses decreased $112 million in the second quarter of 2015 compared to the second quarter of 2014. North America E&P declined $38 million due to lower operational, maintenance and labor costs. International E&P declined $35 million primarily because of lower costs related to lower sales volumes, while the second quarter of 2014 included $5 million of turnaround costs at Brae and subsea maintenance costs at the non-operated Foinaven field in the U.K. OSM decreased $39 million primarily due to lower feedstock purchases (due to planned turnarounds and

unplanned downtime as previously discussed) and continued cost management, especially staffing and contract labor. Also contributing to the OSM decrease was a more favorable exchange rate on expenses denominated in the Canadian Dollar. These declines were partially offset by costs incurred from the turnaround.
Production expenses for the first six months of 2015 decreased by $210 million compared to the same period of 2014. North America E&P declined $47 million due to lower operational, maintenance and labor costs. International E&P declined

$68 million due to lower repair, maintenance and turnaround costs as well as lower production volumes. The previous six month period included $11 million of non-recurring riser repair costs in E.G., $5 million of expenses from a Brae turnaround and costs related to reliability issues and subsea maintenance at the non-operated Foinaven field in the U.K. OSM decreased $95 million due to the same reasons as described in the preceding paragraph.
The second quarter of 2015 production expense rate (expense per boe) for North America E&P declined relative to the same quarter in 2014 due to overall cost reductions, as previously discussed, and leveraging efficiencies as production volumes increased. The expense rate for International E&P declined due to reduced maintenance and project costs in second quarter of 2015 as compared to 2014. The OSM expense rate increased due to the turnarounds and unplanned downtime in the second quarter of 2015, which resulted in lower sales volumes and higher costs.
The expense rate during the first six months of 2015 compared the same period in 2014 decreased for North America E&P due to overall cost reductions as discussed in the preceding paragraph. The International E&P expense rate decreased in the first six months of 2015 due to lower project costs as discussed in the preceding paragraphs. The OSM expense rate remained relatively flat in the six months of 2015 as the lower feedstock purchases, cost management and a favorable exchange rate were offset by the aforementioned higher turnaround costs. The following table provides production expense rates for each segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
($ per boe)	2015	2014	2015	2014
Production Expense Rate				
North America E&P	$7.19	$10.47	$7.57	$10.74
International E&P	$6.51	$8.87	$6.45	$8.82
Oil Sands Mining [a]	$78.24	$51.53	$50.06	$49.54

(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 $432 million and $769 million in the second quarter and first six months of 2015 from the comparable 2014 periods, consistent with the marketing revenues changes discussed above.
Exploration expenses declined $34 million in the second quarter of 2015 compared to the second quarter of 2014 due to lower unproved property impairments and dry well costs. Unproved property impairments declined primarily as a result of fewer Eagle Ford and Bakken leases that either expired or that we decided not to drill or extend. The second quarter of 2014 included dry well costs associated with our exploration programs in Kurdistan, Ethiopia and Kenya. Included in the dry well costs for the second quarter of 2015 is $38 million of previously suspended well costs that were written off. The well costs are associated with our Canadian in-situ assets at Birchwood. See Note 11 to the consolidated financial statements for further discussion.
Exploration expenses were $17 million lower in the first six months of 2015 than in the comparable 2014 period due to lower unproved property impairments, which were partially offset by higher dry well costs. Unproved property impairments were higher in 2014 primarily as a result of Eagle Ford and Bakken leases that either expired or that we decided not to drill or extend. Dry well costs increased for the first six months of 2015 due to costs associated with the Sodalita West #1 well in E.G., the Key Largo well in the Gulf of Mexico, and the aforementioned suspended well costs related to Birchwood in-situ. Dry well costs for the first six months of 2014 primarily consist of our exploration programs in Kurdistan, Ethiopia and Kenya. The following table summarizes the components of exploration expenses:

	Three Months Ended		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Exploration Expenses				
Unproved property impairments	$40	$60	$49	$101
Dry well costs	41	53	99	55
Geological and geophysical	12	6	15	17
Other	18	26	38	45
Total exploration expenses	$111	$145	$201	$218

Depreciation, depletion and amortization ("DD&A") increased $71 million and $249 million in the second quarter and first six months of 2015 from the comparable 2014 periods primarily as a result of higher North America E&P net sales volumes from our three U.S. resource plays, partially offset by lower International E&P sales volumes. OSM net sales volumes also declined in the second quarter of 2015, as previously discussed, also contributing to that quarter's decrease. 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.

	Three Months Ended		Six Months Ended June 30,	
($ per boe)	2015	2014	2015	2014
DD&A Rate				
North America E&P	$25.45	$26.58	$26.16	$26.72
International E&P	$7.17	$6.64	$6.62	$6.45
Oil Sands Mining	$12.87	$11.78	$12.58	$11.74

Impairments are discussed in Note 12 to the consolidated financial statements.

Taxes other than income include production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to revenue and sales volumes. With the decrease in North America E&P revenues due to lower price realizations, taxes other than income decreased $31 million and $59 million in the second quarter and first six months of 2015 from the comparable 2014 periods. This decrease was partially offset by an increase in sales volumes in North America E&P. The following table summarizes the components of taxes other than income:

	Three Months Ended		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Production and severance	$40	$68	$74	$122
Ad valorem	15	19	31	38
Other	23	22	40	44
Total	$78	$109	$145	$204

General and administrative expenses increased $29 million in the second quarter of 2015 compared to the same period in 2014 primarily due to higher pension settlement charges. Settlement charges in the second quarter of 2015 totaled $64 million, compared to settlement charges of $8 million in the prior year quarter. This increase in pension settlement costs was partially offset by costs savings realized from the workforce reductions that occurred in the first quarter of 2015.

General and administrative expenses increased $13 million in the first six months of 2015 compared to the same period in 2014. This increase was primarily due to $43 million of severance related expenses in the first quarter of 2015 and $10 million of increased pension settlement expense (first six months of 2015 totaled $81 million as compared to $71 million for the previous year). These increased costs were partially offset by costs savings realized in the second quarter of 2015 resulting from the workforce reductions.

Provision (benefit) for income taxes reflect effective tax rates of 2% and 18% in the second quarter and first six months of 2015, as compared to 30% and 32% from the comparable 2014 periods. The effective rates for 2015 reflect $135 million of non-cash additional deferred tax expense recorded in the second quarter of 2015 as a result of enacted corporate tax changes in Alberta, Canada. See Note 8 to the consolidated financial statements for discussion of the effective tax rate.

Discontinued operations presented in 2014 are net of tax. See Note 5 to the consolidated financial statements for financial information about discontinued operations.

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):

	Three Months Ended		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
North America E&P	$(45)	$302	$(206)	$544
International E&P	41	160	64	381
Oil Sands Mining	(77)	55	(96)	119
Segment income (loss)	(81)	517	(238)	1,044
Items not allocated to segments, net of income taxes	(305)	(157)	(424)	(286)
Income (loss) from continuing operations	(386)	360	(662)	758
Discontinued operations [(a)]	—	180	—	931
Net income (loss)	$(386)	$540	$(662)	$1,689

(a) As a result of the sale of our Angola assets and our Norway business, both are reflected as discontinued operations in 2014.

North America E&P segment income (loss) decreased $347 million and $750 million after-tax in the second quarter and first six months of 2015 from the comparable 2014 periods. The decrease is primarily due to lower price realizations, which was partially offset by the impacts from the increased net sales volumes from the U.S. resource plays.

International E&P segment income decreased $119 million and $317 million after-tax in the second quarter and first six months of 2015 from the comparable 2014 periods. The decreases are primarily due to lower liquid hydrocarbon price realizations and net sales volumes, as well as reduced income from equity investments. These declines were partially offset by lower production and exploration expenses.

Oil Sands Mining segment income (loss) decreased $132 million and $215 million after-tax in the second quarter and first six months of 2015 from the comparable 2014 periods primarily due to lower price realizations, partially offset by reduced production expenses.

Critical Accounting Estimates

There have been no changes to our critical accounting estimates subsequent to December 31, 2014.

Accounting Standards Not Yet Adopted

See Note 2 to the consolidated financial statements.

Cash Flows and Liquidity

Cash Flows

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

	Six Months Ended June 30,	
(In millions)	2015	2014
Sources of cash and cash equivalents		
Continuing operations	$717	$2,118
Discontinued operations	—	440
Borrowings	1,996	—
Disposals of assets	2	2,232
Other	43	113
Total sources of cash and cash equivalents	$2,758	$4,903
Uses of cash and cash equivalents		
Cash additions to property, plant and equipment	$(2,320)	$(2,230)
Investing activities of discontinued operations	—	(233)
Purchases of short-term investments	(925)	—
Debt issuance costs	(19)	—
Debt repayments	(34)	(34)
Dividends paid	(285)	(260)
Purchases of common stock	—	(1,000)
Commercial paper, net	—	(135)
Other	(1)	(10)
Cash held for sale	—	(96)
Total uses of cash and cash equivalents	$(3,584)	$(3,998)

Commodity prices began declining in the second half of 2014 and remain substantially lower through 2015 as compared to the first six months of 2014. This lower price trend adversely impacted our cash flows in 2015. Partially offsetting the decline in prices were increased net sales volumes in the North America E&P segment. While we are unable to predict future commodity price movements, if this lower price environment continues, it would continue to negatively impact our cash flows from operating activities as compared to the previous year.

Borrowings reflect net proceeds received from the issuance of senior notes in June 2015. See Liquidity and Capital Resources below for additional information.

Cash flows from discontinued operations are primarily related to our Norway business, which we disposed of in the fourth quarter of 2014. Disposals of assets in the first six months of 2014 primarily reflect the net proceeds from the sales of our Angola assets. Disposition transactions are discussed in further detail in Note 5 to the consolidated financial statements.

Purchases of short-term investments were made from proceeds received from the senior notes issuance in June 2015. The investments consist of time deposits with maturity dates ranging from September - October 2015.

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

	Six Months Ended June 30,	
(In millions)	2015	2014
North America E&P	$1,484	$1,969
International E&P	245	220
Oil Sands Mining	37	123
Corporate	14	13
Total capital expenditures	1,780	2,325
(Increase) decrease in capital expenditure accrual	540	(95)
Total use of cash and cash equivalents for property, plant and equipment	$2,320	$2,230

During the first six months of 2014, we acquired 29 million common shares at a cost of $1 billion under our share repurchase program, 13 million of which were acquired in the second quarter of 2014 at a cost of $449 million.

Liquidity and Capital Resources

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

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

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

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

Our main sources of liquidity are cash and cash equivalents, short-term investments, internally generated cash flow from operations, the issuance of notes, our $3 billion Credit Facility and sales of non-core assets. Our working capital requirements are supported by these sources and we may also issue commercial paper, which is backed by our revolving credit facility. Furthermore, we actively manage our capital spending program, including the level and timing of activities associated with our drilling programs. Because of the alternatives available to us as discussed above, and access to capital markets through the shelf registration discussed below, we believe that our liquidity is adequate to fund not only our current operations, but also our funding requirements for the foreseeable future, 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.

Outlook

We expect our capital, investment and exploration spending budget for full-year 2015 to be at or below $3.3 billion and estimate full-year North America E&P and International E&P production volumes (excluding Libya) to be 375-390 net mboed.

Capital Resources

Credit Arrangements and Borrowings

At June 30, 2015, we had no borrowings against our revolving credit facility and no amounts outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

At June 30, 2015, we had $8.4 billion in long-term debt outstanding, of which approximately $1.0 billion matures in the fourth quarter of 2015. 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.

Cash and Short-Term Investments-Adjusted Debt-To-Capital Ratio

Our cash and short-term investments-adjusted debt-to-capital ratio (total debt-minus-cash and cash equivalents and short-term investments to total debt-plus-equity-minus-cash and cash equivalents and short-term investments) was 22% at June 30, 2015, compared to 16% at December 31, 2014.

(In millions)	June 30, 2015	December 31, 2014
Long-term debt due within one year	$1,035	$1,068
Long-term debt	7,321	5,323
Total debt	$8,356	$6,391
Cash and cash equivalents	$1,572	$2,398
Short-term investments	$925	$—
Equity	$20,218	$21,020
Calculation:		
Total debt	$8,356	$6,391
Minus cash and cash equivalents	1,572	2,398
Minus short-term investments	925	—
Total debt minus cash, cash equivalents and short-term investments	$5,859	$3,993
Total debt	$8,356	$6,391
Plus equity	20,218	21,020
Minus cash and cash equivalents	1,572	2,398
Minus short-term investments	925	—
Total debt plus equity minus cash, cash equivalents and short-term investments	$26,077	$25,013
Cash and short-term investments-adjusted debt-to-capital ratio	22 %	16 %

Capital Requirements

As noted above in "Outlook," we expect our total capital, investment and exploration spending budget for full-year 2015 to be at or below $3.3 billion.

On July 29, 2015, our Board of Directors approved a dividend of $0.21 per share for the second quarter of 2015 payable September 10, 2015 to stockholders of record at the close of business on August 19, 2015.

As of June 30, 2015, we plan to make contributions of up to $42 million to our funded pension plans during the remainder of 2015.

Contractual Cash Obligations

As of June 30, 2105, there are no material changes to our consolidated cash obligations to make future payments under existing contracts, as disclosed in our 2014 Annual Report on Form 10-K, except for our issuance of $2 billion aggregate principal amount of unsecured senior notes, as more fully described in Note 15.

Environmental Matters

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.

There have been no significant changes to our environmental matters subsequent to December 31, 2014.

Other Contingencies

We are a defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations 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 included or incorporated by reference in this report are forward-looking statements, including without limitation statements regarding our operational, financial and growth strategies, our ability to effect those strategies and the expected timing and results thereof, planned capital expenditures and the impact thereof, future drilling plans, timing and expectations, maintenance activities and the timing and impact thereof, well spud timing and expectations, our financial and operational outlook and ability to fulfill that outlook, our financial position, liquidity and capital resources, our 2015 budget and planned allocation, and the plans and objectives of our management for our future operations. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as “anticipate,” “believe,” “estimate,” “expect,” “target,” “plan,” “project,” “could,” “may,” “should,” “woul
words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, a number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including supply/demand levels and the resulting impact on price;
- changes in expected reserve or production levels;
- changes in political or economic conditions in key operating markets, including international markets;
- capital available for exploration and development;
- well production timing;
- availability of drilling rigs, materials and labor;
- difficulty in obtaining necessary approvals and permits;
- non-performance by third parties of contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- cyber-attacks;
- changes in safety, health, environmental and other regulations;
- other geological, operating and economic considerations; and
- the risk factors, forward-looking statements and challenges and uncertainties described in our 2014 Annual Report on Form 10-K, and those set forth from time to time in our 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. Except as required by law, we assume no duty 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 2014 Annual Report on Form 10-K. 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, may be found in Notes 12 and 13 to the consolidated financial statements.

Commodity Price Risk During the first six months of 2015, we entered into crude oil derivatives, indexed to NYMEX WTI, related to a portion of our forecasted North America E&P sales. The table below provides a summary of open positions as of June 30, 2015:

Financial Instrument	Weighted Average Price	Barrels per day	Remaining Term
Three-Way Collars			
Ceiling	$70.34	35,000	July- December 2015 [(a)]
Floor	$55.57		
Sold put	$41.29		
Ceiling	$71.84	12,000	January- December 2016
Floor	$60.48		
Sold put	$50.00		
Ceiling	$73.13	2,000	January- June 2016 [(b)]
Floor	$65.00		
Sold put	$50.00		
Call Options	$72.39	10,000	January- December 2016 [(c)]

(a) Counterparties have the option to execute fixed-price swaps (swaptions) at a weighted average price of $71.67 per barrel indexed to NYMEX WTI, which is exercisable on October 30, 2015. If counterparties exercise, the term of the fixed price swaps would be for calendar year 2016 and, if all such are exercised, 25,000 barrels per day.

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

(c) Call options settle monthly.

The following table provides a sensitivity analysis of the projected incremental effect on income (loss) from operations of a hypothetical 10% change in NYMEX WTI prices on our open commodity derivative instruments as of June 30, 2015.

(In millions)	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Crude oil commodity derivatives	$(67)	$51

Interest Rate Risk Sensitivity analysis of the incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of June 30, 2015, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities):		
Long term debt, including amounts due within one year	$(8,720) [(a)(b)]	$(288)

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

(b) 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, 2015.

During the second quarter of 2015, 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.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2015	2014	2015	2014
Segment Income (Loss)				
North America E&P	$(45)	$302	$(206)	$544
International E&P	41	160	64	381
Oil Sands Mining	(77)	55	(96)	119
Segment income (loss)	(81)	517	(238)	1,044
Items not allocated to segments, net of income taxes	(305)	(157)	(424)	(286)
Income (loss) from continuing operations	(386)	360	(662)	758
Discontinued operations [a]	—	180	—	931
Net income (loss)	$(386)	$540	$(662)	$1,689
Capital Expenditures [b]				
North America E&P	$551	$1,102	$1,484	$1,969
International E&P	99	115	245	220
Oil Sands Mining	16	55	37	123
Corporate	12	10	14	13
Discontinued operations [a]	—	141	—	251
Total	$678	$1,423	$1,780	$2,576
Exploration Expenses				
North America E&P	$91	$82	$126	$139
International E&P	20	63	75	79
Total	$111	$145	$201	$218

(a) As a result of the sale of our Angola assets and our Norway business, both are reflected as discontinued operations in 2014.

(b) Includes accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Net Sales Volumes	2015	2014	2015	2014
North America E&P				
Crude Oil and Condensate (mbbld)				
Bakken	54	44	53	41
Eagle Ford	82	67	87	65
Oklahoma Resource Basins	5	2	5	2
Other North America [(c)]	35	38	35	36
Total Crude Oil and Condensate	176	151	180	144
Natural Gas Liquids (mbbld)				
Bakken	3	3	3	2
Eagle Ford	26	16	26	16
Oklahoma Resource Basins	6	6	6	5
Other North America [(c)]	2	2	3	4
Total Natural Gas Liquids	37	27	38	27
Total Liquid Hydrocarbons (mbbld)				
Bakken	57	47	56	43
Eagle Ford	108	83	113	81
Oklahoma Resource Basins	11	8	11	7
Other North America [(c)]	37	40	38	40
Total Liquid Hydrocarbons	213	178	218	171
Natural Gas (mmcfd)				
Bakken	22	18	20	17
Eagle Ford	164	111	167	109
Oklahoma Resource Basins	81	61	79	58
Other North America [(c)]	94	104	94	113
Total Natural Gas	361	294	360	297
Equivalent Barrels (mboed)				
Bakken	61	50	59	46
Eagle Ford	135	102	141	99
Oklahoma Resource Basins	24	18	24	17
Other North America [(c)]	54	57	54	58
Total North America E&P	274	227	278	220

[(c)] Includes Gulf of Mexico and other conventional onshore U.S. production.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Net Sales Volumes	2015	2014	2015	2014
International E&P				
Crude Oil and Condensate (mbbld)				
Equatorial Guinea	19	20	18	22
United Kingdom	14	13	14	13
Total Crude Oil and Condensate	33	33	32	35
Natural Gas Liquids (mbbld)				
Equatorial Guinea	9	11	10	11
Total Natural Gas Liquids	9	11	10	11
Total Liquid Hydrocarbons (mbbld)				
Equatorial Guinea	28	31	28	33
United Kingdom	14	13	14	13
Total Liquid Hydrocarbons	42	44	42	46
Natural Gas (mmcfd)				
Equatorial Guinea	365	446	390	441
United Kingdom [(d)]	31	28	32	29
Libya	—	—	—	1
Total Natural Gas	396	474	422	471
Equivalent Barrels (mboed)				
Equatorial Guinea	89	105	93	107
United Kingdom [(d)]	19	18	19	18
Total International E&P	108	123	112	125
Oil Sands Mining				
Synthetic Crude Oil (mbbld) [(e)]	29	44	44	45
Total Continuing Operations (mboed)	411	394	434	390
Discontinued Operations - Angola (mboed) [(a)]	—	—	—	3
Discontinued Operations - Norway (mboed) [(a)]	—	70	—	70
Total Company (mboed)	411	464	434	463
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	4,991	6,624	5,629	6,601
Methanol (mtd)	673	980	778	1,066

(d) Includes natural gas acquired for injection and subsequent resale of 7 mmcfd and 5 mmcfd for the second quarters of 2015 and 2014, and 9 mmcfd and 6 mmcfd for the first six months of 2015 and 2014.

(e) Includes blendstocks.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Average Price Realizations [f]	2015	2014	2015	2014
North America E&P				
Crude Oil and Condensate (per bbl) [g]				
Bakken	$51.36	$93.08	$45.84	$91.43
Eagle Ford	53.47	99.08	47.81	97.65
Oklahoma Resource Basins	51.00	101.12	48.34	98.05
Other North America [c]	52.83	93.45	47.10	91.40
Total Crude Oil and Condensate	52.63	95.95	47.11	94.30
Natural Gas Liquids (per bbl)				
Bakken	$11.63	$45.13	$7.19	$51.04
Eagle Ford	14.08	30.20	13.90	33.76
Oklahoma Resource Basins	14.45	33.04	15.83	38.21
Other North America [c]	25.65	54.13	26.03	57.65
Total Natural Gas Liquids	14.77	34.80	14.60	38.75
Total Liquid Hydrocarbons (per bbl)				
Bakken	$49.29	$90.47	$43.72	$89.16
Eagle Ford	44.05	85.36	40.01	84.78
Oklahoma Resource Basins	30.29	52.00	29.24	55.04
Other North America [c]	50.89	90.45	45.52	88.97
Total Liquid Hydrocarbons	45.96	86.43	41.37	85.65
Natural Gas (per mcf)				
Bakken	$2.62	$4.12	$2.76	$6.14
Eagle Ford	2.71	4.76	2.79	4.83
Oklahoma Resource Basins	2.64	4.57	2.63	5.01
Other North America [c]	2.98	5.65	3.29	5.35
Total Natural Gas	2.76	5.00	2.88	5.14

[f] Excludes gains or losses on derivative instruments.

[g] Inclusion of realized gains on crude oil derivative instruments would have increased average crude oil price realizations by $0.06 and $0.14 per bbl for the second quarter and first six months of 2015. There were no crude oil derivative instruments in 2014.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Average Price Realizations	2015	2014	2015	2014
International E&P				
Crude Oil and Condensate (per bbl)				
Equatorial Guinea	$52.27	$90.91	$47.55	$90.66
United Kingdom	62.97	111.76	60.19	111.38
Total Crude Oil and Condensate	56.70	99.36	52.92	98.51
Natural Gas Liquids (per bbl)				
Equatorial Guinea [(h)]	$1.00	$1.00	$1.00	$1.00
United Kingdom	36.49	64.37	34.82	69.56
Total Natural Gas Liquids	3.10	3.02	3.29	3.64
Total Liquid Hydrocarbons (per bbl)				
Equatorial Guinea	$35.74	$59.72	$31.81	$61.12
United Kingdom	61.93	110.51	58.96	110.02
Total Liquid Hydrocarbons	44.70	75.41	41.06	75.48
Natural Gas (per mcf)				
Equatorial Guinea [(h)]	$0.24	$0.24	$0.24	$0.24
United Kingdom	6.98	8.04	7.34	9.07
Libya	—	—	—	5.45
Total Natural Gas	0.78	0.69	0.78	0.80
Oil Sands Mining				
Synthetic Crude Oil (per bbl)	$52.46	$94.17	$44.33	$91.27
Discontinued Operations - Angola (per boe) [(a)]	—	—	—	$99.82
Discontinued Operations - Norway (per boe) [(a)]	—	$108.11	—	$108.09

(h) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC and Equatorial Guinea LNG Holdings Limited, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P segment.

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Part II – OTHER INFORMATION

Item 1. Legal Proceedings

We are a defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations 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 2014 Annual Report on Form 10-K.

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

The following table provides information about purchases by Marathon Oil during the quarter ended June 30, 2015, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Exchange Act of 1934.

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
04/01/15 - 04/30/15	151,874	27.61	—	$1,500,285,529
05/01/15 - 05/31/15	6,614	29.85	—	$1,500,285,529
06/01/15 - 06/30/15	3,231	27.11	—	$1,500,285,529
Total	161,719	27.69	—	

(a) 161,719 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 quarterly report on 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 6, 2015		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
2.1++	Separation and Distribution Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Oil Company and Marathon Petroleum Corporation	8-K	2.1	5/26/2011
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 April 9, 2015)	8-K	3.1	4/10/2015
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	First Amendment, dated as of May 5, 2015, to the Amended and Restated Credit Agreement dated as of May 28, 2014, by and among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	10-Q	10.1	5/07/2015
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				