MARATHON OIL CORP
Form 10-Q
August 05, 2014

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, 2014

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 674,484,400 shares of Marathon Oil Corporation common stock outstanding as of July 31, 2014.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended June 30, 2014

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Unless the context otherwise indicates, references in this Form 10-Q to “Marathon Oil,” “we,” “our,” or “us” 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).

Part I - Financial Information
Item 1. Financial Statements

MARATHON OIL CORPORATION
Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2014	2013	2014	2013
Revenues and other income:				
Sales and other operating revenues, including related party	$2,270	$2,513	$4,419	$4,961
Marketing revenues	618	497	1,159	929
Income from equity method investments	120	77	257	195
Net gain (loss) on disposal of assets	(87)	(107)	(85)	2
Other income	20	10	40	19
Total revenues and other income	2,941	2,990	5,790	6,106
Costs and expenses:				
Production	562	552	1,104	1,085
Marketing, including purchases from related parties	614	494	1,156	927
Other operating	101	70	204	168
Exploration	145	125	218	582
Depreciation, depletion and amortization	680	626	1,323	1,257
Impairments	4	—	21	38
Taxes other than income	109	93	204	175
General and administrative	139	159	326	322
Total costs and expenses	2,354	2,119	4,556	4,554
Income from operations	587	871	1,234	1,552
Net interest and other	(76)	(67)	(125)	(140)
Income from continuing operations before income taxes	511	804	1,109	1,412
Provision for income taxes	151	563	351	1,013
Income from continuing operations	360	241	758	399
Discontinued operations	180	185	931	410
Net income	$540	$426	$1,689	$809
Per Share Data				
Basic:				
Income from continuing operations	$0.53	$0.34	$1.11	$0.56
Discontinued operations	$0.27	$0.26	$1.36	$0.58
Net income	$0.80	$0.60	$2.47	$1.14
Diluted:				
Income from continuing operations	$0.53	$0.34	$1.10	$0.56
Discontinued operations	$0.27	$0.26	$1.36	$0.58
Net income	$0.80	$0.60	$2.46	$1.14
Dividends	$0.19	$0.17	$0.38	$0.34
Weighted average common shares:				
Basic	676	710	684	709
Diluted	679	714	688	713

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)	2014	2013	2014	2013
Net income	$540	$426	$1,689	$809
Other comprehensive income (loss)				
Postretirement and postemployment plans				
Change in actuarial loss and other	(13)	133	(43)	146
Income tax benefit (provision)	5	(49)	15	(54)
Postretirement and postemployment plans, net of tax	(8)	84	(28)	92
Foreign currency translation and other				
Unrealized gain (loss)	1	(3)	1	(4)
Income tax benefit (provision)	(1)	1	(1)	1
Foreign currency translation and other, net of tax	—	(2)	—	(3)
Other comprehensive income (loss)	(8)	82	(28)	89
Comprehensive income	$532	$508	$1,661	$898

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	June 30, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$1,169	$264
Receivables	2,042	2,134
Inventories	404	364
Other current assets	211	172
Current assets held for sale	392	41
Total current assets	4,218	2,975
Equity method investments	1,184	1,201
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $20,207 and $21,895	27,824	28,145
Goodwill	457	499
Other noncurrent assets	1,088	1,153
Noncurrent assets held for sale	1,164	1,647
Total assets	$35,935	$35,620
Liabilities		
Current liabilities:		
Commercial paper	$—	$135
Accounts payable	2,439	2,206
Payroll and benefits payable	121	240
Accrued taxes	193	1,445
Other current liabilities	147	214
Long-term debt due within one year	68	68
Current liabilities held for sale	1,006	25
Total current liabilities	3,974	4,333
Long-term debt	6,362	6,394
Deferred tax liabilities	2,525	2,492
Defined benefit postretirement plan obligations	668	604
Asset retirement obligations	1,804	2,009
Deferred credits and other liabilities	392	401
Noncurrent liabilities held for sale	342	43
Total liabilities	16,067	16,276
Commitments and contingencies		
Stockholders' Equity		
Preferred stock – no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Securities exchangeable into common stock – no shares issued or outstanding (no par value, 29 million shares authorized)	—	—
Held in treasury, at cost – 97 million and 73 million shares	(3,718)	(2,903)
Additional paid-in capital	6,530	6,592
Retained earnings	16,564	15,135
Accumulated other comprehensive loss	(278)	(250)

Total stockholders' equity	19,868	19,344
Total liabilities and stockholders' equity	$35,935	$35,620

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
(In millions)	2014	2013
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$1,689	$809
Adjustments to reconcile net income to net cash provided by operating activities:		
Discontinued operations	(931)	(410)
Deferred income taxes	173	35
Depreciation, depletion and amortization	1,323	1,257
Impairments	21	38
Pension and other postretirement benefits, net	26	33
Exploratory dry well costs and unproved property impairments	156	494
Net (gain) loss on disposal of assets	85	(2)
Equity method investments, net	(10)	—
Changes in:		
Current receivables	(266)	(11)
Inventories	(58)	(19)
Current accounts payable and accrued liabilities	(31)	(284)
All other operating, net	(59)	(18)
Net cash provided by continuing operations	2,118	1,922
Net cash provided by discontinued operations	440	474
Net cash provided by operating activities	2,558	2,396
Investing activities:		
Additions to property, plant and equipment	(2,230)	(2,405)
Disposal of assets	2,232	333
Investments - return of capital	27	29
Investing activities of discontinued operations	(233)	(271)
All other investing, net	—	15
Net cash used in investing activities	(204)	(2,299)
Financing activities:		
Commercial paper, net	(135)	(200)
Debt repayments	(34)	(148)
Purchases of common stock	(1,000)	—
Dividends paid	(260)	(241)
All other financing, net	86	46
Net cash used in financing activities	(1,343)	(543)
Effect of exchange rate on cash and cash equivalents:		
Continuing operations	—	4
Discontinued operations	(10)	4
Cash held for sale	(96)	—
Net increase (decrease) in cash and cash equivalents	905	(438)
Cash and cash equivalents at beginning of period	264	684
Cash and cash equivalents at end of period	$1,169	$246

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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, in the opinion of management, these statements reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been prepared in accordance with the applicable rules of the 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 of America for complete financial statements.

As the result of the sale of our Angola assets in the first quarter of 2014 and the pending sale of our Norway business (see Note 5), the Angola and Norway businesses are reflected as discontinued operations in all periods presented. The disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations, unless otherwise noted. Assets and liabilities of these businesses are presented as held for sale in the consolidated balance sheets as of December 31, 2013 and June 30, 2014.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation 2013 Annual Report on Form 10-K. The results of operations for the second quarter and first six months of 2014 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Not Yet Adopted

In May 2014, the Financial Accounting Standards Board ("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 2017 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 not permitted. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

In April 2014, the FASB issued an amendment to accounting standards that changes the criteria for reporting discontinued operations while enhancing related disclosures. Under the amendment, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization’s operations and financial results. Examples include disposal of a major geographic area, a major line of business, or a major equity method investment. Expanded disclosures about the assets, liabilities, income and expenses of discontinued operations will be 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 are effective for us in the first quarter of 2015 and early adoption is permitted. We are evaluating the provisions of this amendment and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In June 2013, the FASB ratified the Emerging Issues Task Force consensus which requires that an unrecognized tax benefit (or a portion thereof) be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update was effective for us beginning in the first quarter of 2014 and is required to be applied prospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within United States Generally Accepted Accounting Principles ("U.S. GAAP"). This accounting standards update was effective for us beginning in the first quarter of 2014 and is required to be applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

3. Variable Interest Entity

The owners of the Athabasca Oil Sands Project ("AOSP"), in which we hold a 20 percent undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. Costs under this contract are accrued and recorded on a monthly basis, with current liabilities of $3 million recorded at June 30, 2014, consistent with December 31, 2013. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a variable interest entity ("VIE"). We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore the Corridor Pipeline is not consolidated by 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 $622 million as of June 30, 2014. 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 per Common Share

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options, provided the effect is not antidilutive. The per share calculations below exclude 5 million and 6 million stock options for the second quarters of 2014 and 2013 and 4 million and 6 million stock options for the first six months of 2014 and 2013 as they were antidilutive.

	Three Months Ended June 30,			
	2014		2013	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$360	$360	$241	$241
Discontinued operations	180	180	185	185
Net income	$540	$540	$426	$426
Weighted average common shares outstanding	676	676	710	710
Effect of dilutive securities	—	3	—	4
Weighted average common shares, including dilutive effect	676	679	710	714
Per share:				
Income from continuing operations	$0.53	$0.53	$0.34	$0.34
Discontinued operations	$0.27	$0.27	$0.26	$0.26
Net income	$0.80	$0.80	$0.60	$0.60

	Six Months Ended June 30,			
	2014		2013	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$758	$758	$399	$399
Discontinued operations	931	931	410	410
Net income	$1,689	$1,689	$809	$809
Weighted average common shares outstanding	684	684	709	709
Effect of dilutive securities	—	4	—	4
Weighted average common shares, including dilutive effect	684	688	709	713
Per share:				
Income from continuing operations	$1.11	$1.10	$0.56	$0.56

Discontinued operations	$1.36	$1.36	$0.58	$0.58
Net income	$2.47	$2.46	$1.14	$1.14

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

5. Dispositions
2014 - International Exploration and Production ("E&P") Segment

In June 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, with an effective date of January 1, 2014. We expect the transaction to close in the fourth quarter of 2014, pending government and regulatory approvals, with net proceeds of $2.1 billion. Our Norway business is reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Select amounts reported in discontinued operations were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Revenues applicable to discontinued operations	$693	$828	$1,373	$1,732
Pretax income from discontinued operations	$598	$662	$1,130	$1,422
After-tax income from discontinued operations	$180 [(a)]	$158	$322 [(a)]	$380

(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.

Assets and liabilities presented as held for sale in the June 30, 2014 consolidated balance sheet reflect the Norway business.

In the first quarter of 2014, we closed the sales of our non-operated 10 percent working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. A $576 million after-tax gain on the sale of our Angola assets was recorded in the first quarter of 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that would have otherwise 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 all periods presented. Select amounts reported in discontinued operations were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Revenues applicable to discontinued operations	$—	$79	$58	$165
Pretax income from discontinued operations	$—	$37	$51	$78
After-tax income from discontinued operations	$—	$27	$33	$30
Pretax gain on disposition of discontinued operations	$—	$—	$470	$—

Assets and liabilities presented as held for sale in the December 31, 2013 consolidated balance sheet reflect the Angola business.

2014 - North America E&P Segment

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

2013 - North America E&P Segment

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

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

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

In February 2013, we closed the sale of our interest in the Neptune gas plant, located onshore Louisiana, for proceeds of $166 million. A $98 million pretax gain was recorded in the first quarter of 2013.
In January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments were made in the second quarter of 2013, the pretax gain on this sale was $55 million.

6. Segment Information

We have three reportable operating segments. Each of these segments is organized 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 liquid hydrocarbons and natural gas in North America;
- International E&P ("Int'l E&P") – explores for, produces and markets liquid hydrocarbons 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; and
- Oil Sands Mining ("OSM") – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations excluding certain items not allocated to segments, net of income taxes, attributable to the operating segments. 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. Unrealized gains or losses on crude oil derivative instruments, certain impairments, gains or losses on dispositions or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.
As discussed in Note 5, we sold our Angola assets in the first quarter of 2014 and entered into an agreement to sell our Norway business in June 2014. The Angola and Norway businesses are reflected as discontinued operations and are excluded from the International E&P segment in all periods presented.

	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)	(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 [(c)]	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] Includes pension settlement loss of $8 million.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended June 30, 2013				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$1,284	$826	$353	$50 [c]	$2,513
Marketing revenues	439	49	9	—	497
Total revenues	1,723	875	362	50	3,010
Income from equity method investments	—	77	—	—	77
Net gain (loss) on disposal of assets and other income	6	7	3	(113)	(97)
Less:					
Production expenses	195	83	274	—	552
Marketing costs	438	47	9	—	494
Exploration expenses	76	49	—	—	125
Depreciation, depletion and amortization	490	77	48	11	626
Other expenses [a]	94	21	2	112 [d]	229
Taxes other than income	86	—	5	2	93
Net interest and other	—	—	—	67	67
Income tax provision (benefit)	129	512	7	(85)	563
Segment income/Income from continuing operations	$221	$170	$20	$(170)	$241
Capital expenditures [b]	$904	$107	$98	$10	$1,119

(a)Includes other operating expenses and general and administrative expenses.
(b)Includes accruals.
(c)Unrealized gain on crude oil derivative instruments.
(d)Includes pension settlement loss of $17 million

	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)	(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 [c]	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) Includes pension settlement loss of $71 million.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30, 2013				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$ 2,499	$ 1,721	$ 741	$ —	$ 4,961
Marketing revenues	784	136	9	—	929
Total revenues	3,283	1,857	750	—	5,890
Income from equity method investments	—	195	—	—	195
Net gain (loss) on disposal of assets and other income	6	23	3	(11)	21
Less:					
Production expenses	379	161	545	—	1,085
Marketing costs	785	133	9	—	927
Exploration expenses	511	71	—	—	582
Depreciation, depletion and amortization	968	168	100	21	1,257
Impairments	23	—	—	15	38
Other expenses [(a)]	200	64	10	216 [(c)]	490
Taxes other than income	162	—	11	2	175
Net interest and other	—	—	—	140	140
Income tax provision (benefit)	99	1,035	20	(141)	1,013
Segment income/Income from continuing operations	$ 162	$ 443	$ 58	$ (264)	$ 399
Capital expenditures [(b)]	$ 1,874	$ 194	$ 143	$ 40	$ 2,251

[(a)] Includes other operating expenses and general and administrative expenses.
[(b)] Includes accruals.
[(c)] Includes pension settlement loss of $17 million.

7. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Service cost	$ 11	$ 13	$ 1	$ 1
Interest cost	15	16	3	3
Expected return on plan assets	(14)	(16)	—	—
Amortization:				
– prior service cost (credit)	2	1	(1)	(1)
– actuarial loss	10	16	—	—
Net settlement loss[(a)]	8	17	—	—
Net periodic benefit cost	$ 32	$ 47	$ 3	$ 3

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Service cost	$23	$26	$2	$2
Interest cost	31	31	6	6
Expected return on plan assets	(32)	(33)	—	—
Amortization:				
– prior service cost (credit)	3	3	(2)	(3)
– actuarial loss	16	29	—	—
Net settlement loss[a]	71	17	—	—
Net periodic benefit cost	$112	$73	$6	$5

(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.

During the first and second quarters of 2014 and the second quarter of 2013, we recorded the effects of partial settlements of our United States ("U.S.") pension plans and we remeasured the plans' assets and liabilities as of the applicable balance sheet dates. As a result, we recognized pretax decreases of $68 million and $32 million in actuarial losses in other comprehensive income for the second quarter and first six months of 2014 and a pretax decrease of $139 million in actuarial losses in other comprehensive income for the second quarter and first six months of 2013.

During the first six months of 2014, we made contributions of $37 million to our funded pension plans. We expect to make additional contributions up to an estimated $52 million to our funded pension plans over the remainder of 2014. Current benefit payments related to unfunded pension and other postretirement benefit plans were $47 million and $8 million during the first six months of 2014.

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 provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments 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 2014 and 2013 were 32 percent and 72 percent. The decrease in the effective tax rate on continuing operations in the first six months of 2014 is primarily due to a decrease in pretax income from Libya operations, where the tax rate is in excess of 90 percent. In Libya, we have had no oil liftings since July 2013 due to third-party labor strikes at the Es Sider oil terminal.

The tax provision (benefit) applicable to Libyan ordinary income (loss) was recorded as a discrete item in the first six months of 2014 and 2013. Excluding Libya, the effective tax rates on continuing operations would be 34 percent and 39 percent for the first six months of 2014 and 2013. In Libya, there remains uncertainty around future production and sales levels. Reliable estimates of 2014 and 2013 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. As such, for the first six months of 2014 and 2013, estimated annual effective tax rates were calculated excluding Libya and applied to consolidated ordinary income excluding Libya.

We have reviewed our foreign operations, including the disposition of Norway, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings of $746 million associated with our United Kingdom ("U.K.") operations to be permanently reinvested outside the U.S. Foreign tax credits associated with these earnings would be sufficient to offset any incremental U.S. tax liabilities. The remaining undistributed income of certain consolidated foreign subsidiaries for which no U.S. deferred income tax provision has been recorded because we intend to permanently reinvest such income in our foreign operations amounted to $862 million at June 30, 2014. If such income was not permanently reinvested, income tax expense of approximately $302 million would be recorded, not including potential utilization of foreign tax credits.

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9. Inventories

Inventories are carried at the lower of cost or market value.

(In millions)	June 30, 2014	December 31, 2013
Liquid hydrocarbons, natural gas and bitumen	$100	$55
Supplies and other items	304	309
Inventories, at cost	$404	$364

10. Property, Plant and Equipment

(In millions)	June 30, 2014	December 31, 2013
North America E&P	$15,595	$14,973
International E&P [(a)]	2,617	3,590
Oil Sands Mining	9,494	9,447
Corporate	118	135
Net property, plant and equipment	$27,824	$28,145

(a) International E&P decrease is due to Norway assets reflected as held for sale in the June 30, 2014 consolidated balance sheet.

Beginning in the third quarter of 2013, our Libya operations have been impacted by on-going third-party labor strikes at the Es Sider oil terminal. In early July 2014, Libya's National Oil Corporation rescinded force majeure associated with these third-party labor strikes. However, liftings have yet to resume and there remains uncertainty around future production and sales levels. As of June 30, 2014, our net property, plant and equipment investment in Libya is approximately $772 million. 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.

Exploratory well costs capitalized greater than one year after completion of drilling were $102 million as of June 30, 2014 (including $44 million related to Norway project costs which are reflected in noncurrent assets held for sale) and $281 million as of December 31, 2013 (including $70 million related to Norway project costs). This $179 million net decrease was the result of a $153 million reduction due to the sale of our interests in Angola Blocks 31 and 32 and a decrease of $26 million due to the commencement of drilling at the Boyla development offshore Norway.

11. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations during the first six months of 2014:

(In millions)	
Beginning balance	$2,096
Incurred, including acquisitions	31
Settled, including dispositions	(96)
Accretion expense (included in depreciation, depletion and amortization)	66
Revisions to previous estimates	41
Held for sale	(309)
Ending balance[(a)]	$1,829

(a) Includes asset retirement obligations of $25 million classified as a short-term at June 30, 2014.

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Notes to Consolidated Financial Statements (Unaudited)

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, 2014 and December 31, 2013 by fair value hierarchy level.

	June 30, 2014			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$—	$11	$—	$11
Derivative instruments, assets	$—	$11	$—	$11
Derivative instruments, liabilities				
Foreign currency	$—	$12	$—	$12
Derivative instruments, liabilities	$—	$12	$—	$12

	December 31, 2013			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$—	$8	$—	$8
Foreign currency	—	2	—	2
Derivative instruments, assets	$—	$10	$—	$10
Derivative instruments, liabilities				
Foreign currency	$—	$4	$—	$4
Derivative instruments, liabilities	$—	$4	$—	$4

Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. Foreign currency forwards are measured at fair value with a market approach using third-party pricing services, such as Bloomberg L.P., which have been corroborated with data from active markets for similar assets or liabilities, and are Level 2 inputs.

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,			
	2014		2013	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$—	$4	$—	$—

	Six Months Ended June 30,			
	2014		2013	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$—	$21	$—	$38

All long-lived assets held for use that were impaired in the first six months of 2014 and 2013 were held by our North America E&P segment. The fair values of each discussed below were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

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Notes to Consolidated Financial Statements (Unaudited)

The Ozona development in the Gulf of Mexico ceased producing in the first quarter of 2013 and a $21 million impairment was recorded. 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.

In the first quarter of 2013, as a result of our decision to wind down operations in the Powder River Basin due to poor economics, an impairment of $15 million was recorded.

Other impairments of long-lived assets held for use by our North America E&P segment in the first six months of 2013 were a result of reduced drilling expectations, reductions of estimated reserves or declining natural gas prices.

Fair Values – Financial Instruments

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

The following table summarizes financial instruments, excluding receivables, commercial paper, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at June 30, 2014 and December 31, 2013.

	June 30, 2014		December 31, 2013	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$166	$159	$154	$147
Total financial assets	166	159	154	147
Financial liabilities				
Other current liabilities	13	13	13	13
Long-term debt, including current portion[a]	7,133	6,394	6,922	6,427
Deferred credits and other liabilities	93	147	149	147
Total financial liabilities	$7,239	$6,554	$7,084	$6,587

[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 derivatives are subject to enforceable master netting arrangements or similar agreements under which we may report net amounts. Netting is assessed by counterparty, and as of June 30, 2014 and December 31, 2013, there were no offsetting amounts. Positions by contract were all either assets or liabilities. The following tables present the gross fair values of derivative instruments, excluding cash collateral, and the reported net amounts along with where they appear on the consolidated balance sheets as of June 30, 2014 and December 31, 2013.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	June 30, 2014			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$11	$—	$11	Other noncurrent assets
Total Designated Hedges	$11	$—	$11	

	June 30, 2014			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$—	$12	$12	Current liabilities held for sale
Total Designated Hedges	$—	$12	$12	

	December 31, 2013			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$8	$—	$8	Other noncurrent assets
Foreign currency	2	—	2	Other current assets
Total Designated Hedges	$10	$—	$10	

	December 31, 2013			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$—	$4	$4	Other current liabilities
Total Designated Hedges	$—	$4	$4	

Derivatives Designated as Fair Value Hedges

The following table presents by maturity date, information about our interest rate swap agreements as of June 30, 2014 and December 31, 2013, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

Maturity Dates	Aggregate Notional Amount (in millions)	June 30, 2014 Weighted Average, LIBOR-Based, Floating Rate	December 31, 2013
October 1, 2017	$600	4.64 %	4.65 %
March 15, 2018	$300	4.48 %	4.50 %

As of June 30, 2014 and December 31, 2013, our foreign currency forwards had an aggregate notional amount of 2,870 million and 2,387 million Norwegian Kroner at weighted average forward rates of 6.003 and 6.060. These forwards hedge our current Norwegian tax liability and those outstanding at June 30, 2014 have settlement dates through October 2014.

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

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2014	2013	2014	2013
Derivative					
Interest rate	Net interest and other	$4	$(12)	$3	$(15)
Foreign currency	Discontinued operations	$(14)	$(21)	$(11)	$(46)
Hedged Item					
Long-term debt	Net interest and other	$(4)	$12	$(3)	$15
Accrued taxes	Discontinued operations	$14	$21	$11	$46

Derivatives not Designated as Hedges

The impact of all commodity derivative instruments not designated as hedges appears in sales and other operating revenues in our consolidated statements of income and were net gains of $67 million and $13 million in the second quarter and first six months of 2013.

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 2014:

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2013	18,104,887	$27.27	4,031,888	$31.80
Granted	1,935,423 [(a)]	$34.48	1,887,487	$34.84
Options Exercised/Stock Vested	(3,800,690)	$20.15	(694,785)	$33.10
Canceled	(440,429)	$34.14	(319,737)	$31.65
Outstanding at June 30, 2014	15,799,191	$29.68	4,904,853	$32.79

(a) The weighted average grant date fair value of stock option awards granted was $10.50 per share.

Stock-based performance unit awards

During the first six months of 2014, we granted 221,491 stock-based performance units to certain officers. The grant date fair value per unit was $34.28.

15. Debt

As of June 30, 2014, we had no borrowings against our revolving credit facility, as described below, or under our U.S. commercial paper program that is backed by the revolving credit facility.

In May 2014, we amended our $2.5 billion unsecured revolving credit facility (the "Credit Facility"), including an extension of the maturity to May 2019. Terms of this amended Credit Facility include the ability to request two one-year extensions and an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million. Fees on the unused commitment of each lender range from 8 basis points to 22.5 basis points depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option, at either (a) an adjusted LIBOR rate plus a margin ranging from 87.5 basis points to 150 basis points depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0 basis points to 50 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent or (c) LIBOR for a one-month interest period plus 1 percent.

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

The agreement contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent 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.

16. Reclassifications Out of Accumulated Other Comprehensive Loss

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

	Three Months Ended June 30,		Six Months Ended June 30,		
(In millions)	2014	2013	2014	2013	Income Statement Line
Accumulated Other Comprehensive Loss Components					
	Income (Expense)				
Postretirement and postemployment plans					
Amortization of actuarial loss	$(10)	$(16)	$(16)	(29)	General and administrative
Net settlement loss	(8)	(17)	(71)	(17)	General and administrative
	(18)	(33)	(87)	(46)	Income from operations
	7	12	30	17	Provision for income taxes
Other insignificant, net of tax	—	—	(1)	—	
Total reclassifications	$(11)	$(21)	$(58)	$(29)	Income from continuing operations

17. Stockholders' Equity

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.

18. Supplemental Cash Flow Information

	Six Months Ended June 30,	
(In millions)	2014	2013
Net cash provided by operating activities:		
Interest paid (net of amounts capitalized)	$149	$160
Income taxes paid to taxing authorities [(a)]	1,336	2,474
Commercial paper, net:		
Issuances	$2,285	$2,075
Repayments	(2,420)	(2,275)
Commercial paper, net	(135)	(200)
Noncash investing activities, related to continuing operations:		
Asset retirement costs capitalized	$42	$309
Change in capital expenditure accrual	95	(154)
Asset retirement obligations assumed by buyer	52	92
Receivable for disposal of assets	44	50

(a) Income taxes paid to taxing authorities included $1,076 million and $1,392 million related to discontinued operations in the first six months of 2014 and 2013.

19. 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.

Contractual commitments – At June 30, 2014, Marathon’s contract commitments to acquire property, plant and equipment were $1,209 million.

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

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

- North America E&P – explores for, produces and markets liquid hydrocarbons and natural gas in North America;
- International E&P – explores for, produces and markets liquid hydrocarbons and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in Equatorial Guinea ("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 discussed in Note 5 to the consolidated financial statements, our Angola and Norway businesses are reflected as discontinued operations and are excluded from the International E&P segment in all periods presented. We sold our Angola assets in the first quarter of 2014 and entered into an agreement to sell our Norway business in June 2014 in a transaction expected to close in the fourth quarter of 2014. Assets and liabilities of these businesses are presented as held for sale in the consolidated balance sheets as of December 31, 2013 and June 30, 2014.

Executive Summary

Our net sales volumes from continuing operations for the second quarter and first six months of 2014 averaged 394 thousand barrels of oil equivalent per day ("mboed") and 390 mboed compared to 410 mboed and 418 mboed for the second quarter and first six months of 2013. Since we had no oil liftings from Libya in the second quarter and first six months of 2014 as a result of third-party labor strikes at the Es Sider oil terminal, a more representative comparison is net sales volumes from continuing operations excluding Libya. Excluding Libya, our net sales volumes from continuing operations averaged 361 mboed and 375 mboed for the second quarter and first six months of 2013, representing increases in net sales volume of 9 percent and 4 percent in the second quarter and first six months of 2014. The continued ramp up of production from our U.S. resource plays was the most significant contributor to the 2014 increases when comparing results excluding Libya. Net sales volumes related to the Angola and Norway discontinued operations for the second quarter and first six months of 2014 averaged 70 mboed and 73 mboed compared to 96 mboed and 97 mboed for the second quarter and first six months of 2013, ranging from 15 to 19 percent of total company net sales volumes in those periods.

Net income per diluted share was $0.80 and $2.46 for the second quarter and first six months of 2014, increases of 33 percent and 116 percent over the same periods of 2013, reflecting higher income from our North America E&P and Oil Sands Mining segments driven primarily by higher commodity prices and growth in net sales volumes from our U.S. resource plays. The increase for the first six months of 2014 also reflects the $0.83 per diluted share after-tax gain on the sale of our Angola assets in the first quarter of 2014 and non-cash unproved property impairments on Eagle Ford leases that either expired or that we did not expect to drill or extend in the first quarter of 2013.

Key Operating and Financial Activities

In the second quarter of 2014, notable activities were:

- Increased net income per diluted share to $0.80 compared to $0.60 for the same quarter of 2013
- Increased income from continuing operations per diluted share to $0.53 compared to $0.34 for the same quarter of 2013
- Increased average net sales volumes from the three U.S. resource plays to 170 mboed, up 29 percent from same quarter of last year, with liquid hydrocarbon production up more than 30 percent
- Executed agreements to add approximately 30,000 net acres to our Oklahoma resource position, increasing total net acreage to more than 300,000 net acres
- Recorded 98 percent average operational availability for operated assets
- Reached definitive agreement to sell Norway business for a total transaction value of $2.7 billion; expect to close in the fourth quarter of 2014 with net proceeds of $2.1 billion
- Repurchased approximately 13 million common shares at a cost of $449 million leaving $1.5 billion remaining on the share repurchase authorization

Significant third quarter activity through August 5, 2014 includes:

- Increased quarterly dividend by 11 percent to $0.21 per share

Operations
North America E&P--Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net Sales Volumes				
Crude Oil and Condensate (mbbld)				
Bakken	44	35	41	34
Eagle Ford	67	50	65	48
Oklahoma resource basins	2	1	2	1
Other North America	38	40	36	41
Total Crude Oil and Condensate	151	126	144	124
Natural Gas Liquids (mbbld)				
Bakken	3	2	2	2
Eagle Ford	16	14	16	13
Oklahoma resource basins	6	4	5	4
Other North America	2	2	4	2
Total Natural Gas Liquids	27	22	27	21
Total Liquid Hydrocarbons (mbbld)				
Bakken	47	37	43	36
Eagle Ford	83	64	81	61
Oklahoma resource basins	8	5	7	5
Other North America	40	42	40	43
Total Liquid Hydrocarbons	178	148	171	145
Natural Gas (mmcfd)				
Bakken	18	12	17	13
Eagle Ford	111	99	109	91
Oklahoma resource basins	61	48	58	49
Other North America	104	157	113	175
Total Natural Gas	294	316	297	328
Equivalent Barrels (mboed)				
Bakken	50	39	46	38
Eagle Ford	102	81	99	76
Oklahoma resource basins	18	13	17	13
Other North America	57	68	58	73
Total North America E&P	227	201	220	200

North America E&P segment average net sales volumes in the second quarter and first six months of 2014 increased 13 percent and 10 percent when compared to the second quarter and first six months of 2013. Net liquid hydrocarbon sales volumes increased 30 thousand barrels per day ("mbbld") and 26 mbbld for the second quarter and first six months of 2014, primarily reflecting continued growth across our three U.S. resource plays, partially offset by natural declines in Gulf of Mexico production. The negative impact of extreme winter weather on availability and completion operations in the first quarter of 2014 is reflected in the smaller increase for the six-month period. Net natural gas sales volumes decreased 7 percent and 9 percent during the same periods due primarily to the cessation of production from operated wells in the Powder River Basin in Wyoming and to the sale of our Alaska assets in January 2013, somewhat offset by increases in associated natural gas production from our U.S. resource plays.

Eagle Ford – Average net sales volumes from Eagle Ford were 102 mboed and 99 mboed in the second quarter and first six months of 2014 compared to 81 mboed and 76 mboed in the same periods of 2013, for increases of 26 percent and 30 percent. Approximately 66 percent of second quarter sales were crude oil and condensate, 16 percent was natural gas liquids ("NGLs") and 18 percent was natural gas.

Enhanced completion design in the Eagle Ford is delivering strong early results. Wells with 180-day cumulative production are yielding on average 25 percent improvement relative to modeled type curves. The pace of execution continued to improve along with the transition to higher density pad drilling, as evidenced by the 55 percent increase in the number of wells brought to sales compared to the first quarter of 2014. During the second quarter of 2014, we reached total depth on 88 gross operated wells and brought 76 gross operated wells to sales compared to 82 reaching total depth and 79 brought to sales in the second quarter of 2013. During the first six months of 2014, we reached total depth on 171 gross operated wells and brought 125 gross operated

wells to sales compared to 158 reaching total depth and 148 brought to sales in the same period of 2013. Our second quarter of 2014 average spud-to-total depth time was 13 days compared to 12 days in the same period of 2013.
We continued our successful delineation of the Austin Chalk/Upper Eagle Ford for co-development with an initial 15,500 net acres now delineated. Nine additional Austin Chalk/Upper Eagle Ford wells are currently being drilled, completed or awaiting first production.
Bakken – Average net sales volumes from the Bakken shale were 50 mboed and 46 mboed in the second quarter and first six months of 2014 compared to 39 mboed and 38 mboed in the same periods of 2013, for increases of 28 percent and 21 percent. Our Bakken production averages approximately 90 percent crude oil, four percent NGLs and six percent natural gas. During the second quarter of 2014, we reached total depth on 19 gross operated wells and brought 19 gross operated wells to sales compared to 22 reaching total depth and 16 brought to sales in the second quarter of 2013. During the first six months of 2014, we reached total depth on 35 gross operated wells and brought 30 gross operated wells to sales compared to 40 reaching total depth and 38 brought to sales in the same period of 2013. Our second quarter average time to drill a well was 17 days spud-to-total depth, compared to 15 days in the same period of 2013.
We recompleted eight wells during the second quarter of 2014, and a total of 13 wells in the first six months of 2014, in the Myrmidon and Hector areas. With our continued success in earlier 320-acre spacing pilots, four additional spacing pilots with six Middle Bakken and six Three Forks first bench wells are planned. The first of these new 12-well spacing pilots spud in July, with the remainder planned over the balance of 2014. During the second half of 2014, more than 50 percent of planned Bakken wells will test enhanced completion designs, including elevated proppant volumes, slickwater and hybrid fracs, increased stages and cemented liners.
Oklahoma resource basins – Net sales volumes from the Oklahoma resource basins averaged 18 mboed and 17 mboed in the second quarter and first six months of 2014 compared to 13 mboed in both of the same periods of 2013, for increases of 38 percent and 31 percent. Our Oklahoma resource basins production averaged approximately 44 percent liquid hydrocarbons and 56 percent natural gas for the second quarter of 2014. During the second quarter of 2014, we reached total depth on six gross operated wells and brought four gross SCOOP wells to sales. During the first six months of 2014, we reached total depth on 11 gross operated wells and brought eight gross operated wells to sales.
We continue to test other horizons in Oklahoma, with three operated wells producing in the Southern Mississippi Trend and a second operated Granite Wash horizontal well brought online. Three additional operated wells in the Southern Mississippi Trend are scheduled to spud in the second half of 2014. During the second quarter of 2014, we executed agreements to add approximately 30,000 net acres to our Oklahoma resource position, bringing our overall position to more than 300,000 net acres.
Wyoming – Operated production at the Powder River Basin field ceased in March 2014. Plug and abandonment activities are expected to be completed in the fall of 2014.
North America E&P--Exploration
Gulf of Mexico – A well on the Key Largo prospect, located on Walker Ridge Block 578, is anticipated to spud in the third quarter of 2014 as the first well with a new-build deepwater drillship. We are operator and hold a 60 percent working interest in the prospect.
The second appraisal well on the non-operated Shenandoah prospect was spud in late May 2014 and is still drilling. The well is located on Walker Ridge Block 52, in which we hold a 10 percent working interest.
An exploration well is anticipated to spud in the second half of 2014 on the Perseus prospect, located on Desoto Canyon Block 231. We hold a 30 percent non-operated working interest in the prospect.
North America E&P--Acquisitions and Dispositions
See Note 5 to the consolidated financial statements for information about these dispositions.

International E&P--Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net Sales Volumes				
Total Liquid Hydrocarbons (mbbld)				
Equatorial Guinea	31	30	33	34
United Kingdom	13	14	13	17
Libya	—	45	—	39
Total Liquid Hydrocarbons	44	89	46	90
Natural Gas (mmcfd)				
Equatorial Guinea	446	401	441	424
United Kingdom[(a)]	28	36	29	38
Libya	—	24	1	25
Total Natural Gas	474	461	471	487
Equivalent Barrels (mboed)				
Equatorial Guinea	105	97	107	105
United Kingdom[(a)]	18	20	18	23
Libya	—	49	—	43
Total International E&P (mboed)	123	166	125	171
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	6,624	5,820	6,601	6,301
Methanol (mtd)	980	973	1,066	1,191

(a) Includes natural gas acquired for injection and subsequent resale of 5 mmcfd and 8 mmcfd for the second quarters of 2014 and 2013, and 6 mmcfd and 10 mmcfd for the first six months of 2014 and 2013.

International E&P segment average net sales volumes in the second quarter and first six months of 2014 decreased 26 percent and 27 percent when compared to the second quarter and first six months of 2013. We had lower oil sales from Libya in 2014 as a result of on-going third-party labor strikes at the Es Sider oil terminal. Excluding Libya, net sales volumes increased 5 percent in the second quarter of 2014 and decreased 2 percent in the first six months of 2014 compared to the same periods of 2013. The second quarter 2014 net sales volume increase, excluding Libya, is due to increased sales from Equatorial Guinea due to a planned turnaround at the LNG facility during the second quarter of 2013. The net sales volume decrease for the first six months of 2014, excluding Libya, is primarily related to reliability issues at the non-operated U.K. Foinaven field as well as natural production decline within the U.K. Brae fields.

Equatorial Guinea – Average net sales volumes were 105 mboed and 107 mboed in the second quarter and first six months of 2014 compared to 97 mboed and 105 mboed in the same periods of 2013. Second quarter 2014 net sales volumes are higher than in the same quarter of 2013 because sales volumes were impacted by a planned turnaround at the LNG facility in April 2013. Net sales volumes for the first six months of 2014 are only slightly higher because first quarter 2014 sales were impacted by scheduled offshore riser repairs, an unplanned repair at the methanol plant and a planned nine-day partial shut-down at the LNG facility.

United Kingdom – Average net sales volumes were 18 mboed in both the second quarter and first six months of 2014 compared to 20 mboed and 23 mboed in the same periods of 2013, with decreases of 10 percent and 22 percent, primarily as a result of reliability issues at the non-operated Foinaven field as well as natural decline within the Brae fields and planned and unplanned maintenance activities that resulted in lower overall operating availability. Planned maintenance activities on the non-operated Forties Pipeline System is expected to impact Brae net sales volumes in the third quarter of 2014.

Libya – Libya's National Oil Corporation in early July 2014 rescinded force majeure associated with the third-party labor strikes at the Es Sider oil terminal. However, liftings have yet to resume and there remains uncertainty around future production and sales levels.

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International E&P--Exploration

Kurdistan Region of Iraq – The Jisik-1 exploration well reached total depth in June 2014 on the operated Harir Block. Testing is underway. Following the successful 2013 Mirawa-1 discovery, the Mirawa-2 appraisal well is expected to spud in the third quarter of 2014. We hold a 45 percent operated working interest in the Harir Block.

On the non-operated Sarsang Block, the East Swara Tika-1 exploratory well reached a total depth of approximately 13,000 feet in June 2014 and testing is underway. The co-venturers declared the Swara Tika discovery commercial in May 2014 and filed a field development plan in June. Testing of the Mangesh well was finalized and the well costs were charged to dry well expense in the second quarter of 2014. Due to a contract amendment in April 2014, we hold a 20 percent non-operated working interest in the Sarsang block.

The Chiya Khere-5 development well (formerly Atrush-5), included in the previously approved Atrush development plan, was spud in May 2014 and reached a total depth of approximately 6,900 feet in late June, ahead of schedule and under budget. The well will be tested in early 2015 prior to final completion and tie-in to the phase one production facility as part of the previously approved Atrush development plan. The Atrush-4 development well reached total depth in January 2014. Well testing was completed in April and the well has been suspended as a future producer. We hold a 15 percent non-operated working interest in the Atrush Block.

Kenya – The Sala-1 exploration well was spud in February 2014 on the eastern side of Block 9 and made a natural gas discovery in the second quarter of 2014. The well was drilled to a total depth of approximately 10,000 feet and analysis indicated three zones of interest over a 3,280-foot gross interval which were subsequently drill-stem tested. The Sala-2 appraisal well spud in the third quarter of 2014. We hold a 50 percent non-operated working interest in Block 9 with the option to operate any commercial development.

Ethiopia – Two wells were drilled on the South Omo Block: the Shimela-1 well, which reached total depth in May 2014, and the Gardim-1 well, which reached total depth in July 2014. Neither well encountered commercial hydrocarbons and the well costs were charged to dry well expense in the second quarter of 2014. We hold a 20 percent non-operated interest in the South Omo Block.

Early in 2014, we increased our acreage in Ethiopia through a farm-in to the Rift Basin Area Block with 10.5 million gross acres. We hold a 50 percent non-operated working interest in the block with the option to operate if a discovery is made.

Gabon – In late October 2013, we were the high bidder as operator on the G13 deepwater block in the pre-salt play offshore Gabon. Negotiations toward a final production sharing contract are ongoing.

Poland – During the first quarter of 2014, we relinquished our remaining 4 operated concessions to the government.

International E&P--Acquisitions and Dispositions

In June 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, with an effective date of January 1, 2014. We expect the transaction to close in the fourth quarter of 2014, pending government and regulatory approvals, with net proceeds of $2.1 billion. The Norway business is excluded from the International E&P segment results and is reported as discontinued operations, average net sales volumes from Norway were 70 mboed in both the second quarter and first six months of 2014 compared to 87 mboed and 88 mboed in the same periods of 2013. The decrease was primarily as the result of water breakthrough, as anticipated, at Volund, as well as natural decline in the remaining fields. Alvheim was also impacted in the first quarter of 2014 by severe winter weather which resulted in eight days of curtailed production. Planned maintenance and system upgrades on the Alvheim floating production, storage and offloading vessel are expected to impact production in the third quarter.

In the first quarter of 2014, we closed the sales of our non-operated 10 percent working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. See Note 5 to the consolidated financial statements for information about these dispositions.

Oil Sands Mining

Our Oil Sands Mining operations consist of a 20 percent non-operated working interest in the AOSP. Our net synthetic crude oil sales volumes were 44 mbbld and 45 mbbld in the second quarter and first six months of 2014 compared to 43 mbbld and 47 mbbld in the same periods of 2013. The six-month period of 2014 was impacted by lower mine reliability and nine days of planned mine maintenance in the first quarter of 2014 and a planned turnaround in the second quarter of 2013.

Market Conditions

Prevailing prices for the crude oil, NGLs and natural gas that we produce significantly impact our revenues and cash flows. 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 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Average Price Realizations [a]				
Crude Oil and Condensate (per bbl)				
Bakken	$93.08	$88.65	$91.43	$89.89
Eagle Ford	99.08	99.40	97.65	101.50
Oklahoma resource basins	101.12	90.51	98.05	90.32
Other North America	93.45	91.32	91.40	89.31
Total Crude Oil and Condensate	95.95	93.75	94.30	94.20
Natural Gas Liquids (per bbl)				
Bakken	$45.13	$35.92	$51.04	$38.42
Eagle Ford	30.20	28.09	33.76	28.12
Oklahoma resource basins	33.04	27.99	38.21	34.77
Other North America	54.13	51.05	57.65	53.71
Total Natural Gas Liquids	34.80	31.72	38.75	33.51
Total Liquid Hydrocarbons (per bbl) [b]				
Bakken	$90.47	$85.96	$89.16	$87.23
Eagle Ford	85.36	83.90	84.78	85.88
Oklahoma resource basins	52.00	47.05	55.04	49.88
Other North America	90.45	88.64	88.97	87.02
Total Liquid Hydrocarbons	86.43	84.51	85.65	85.30
Natural Gas (per mcf)				
Bakken	$4.12	$4.47	$6.14	$4.02
Eagle Ford	4.76	4.17	4.83	3.80
Oklahoma resource basins	4.57	4.71	5.01	4.13
Other North America	5.65	4.01	5.35	4.11
Total Natural Gas	5.00	4.19	5.14	4.02
Benchmarks				
West Texas Intermediate ("WTI") crude oil (per bbl)	$102.99	$94.17	$100.84	$94.26
Louisiana Light Sweet ("LLS") crude oil (per bbl)[c]	105.55	104.77	104.97	107.36
Mont Belvieu NGLs (per bbl) [d]	34.54	31.84	36.42	32.84
Henry Hub natural gas[e] (per mmbtu)[f]	4.67	4.09	4.80	3.71

(a) Excludes gains or losses on derivative instruments.

(b) Inclusion of realized gains on crude oil derivative instruments would have increased average liquid hydrocarbon price realizations by $1.26 and $0.50 per bbl for the second quarter and first six months of 2013. There were no crude oil derivative instruments for the second quarter and first six months of 2014.

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

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

(e) Settlement date average.

(f) Million British thermal units.

Crude oil and condensate – The quality and location of our production mix can cause our North America E&P price realizations to differ from the WTI benchmark.

Quality – Light sweet crude contains less sulfur and tends to be lighter than sour crude oil so that refining it is less costly and has historically produced higher value products; therefore, light sweet crude is considered of higher quality and has historically sold at a price that approximates WTI or at a premium to WTI. The percentage of our North America E&P crude oil and condensate production that is classified as light sweet crude has been increasing. In the second quarter and first six months of 2014, the percentage of our U.S. crude oil and condensate production that was sweet averaged 81 percent and 80 percent compared to 75 percent and 74 percent in the same periods of 2013.

Location – Crude oil sold along the U.S. Gulf Coast, such as that from the Eagle Ford, has been priced based on the LLS benchmark which, in recent years, has been at a premium to WTI, while production from inland areas farther from large refineries has been priced lower. As a result of significant increases in U.S. production of light sweet crude oil, the historical relationship between WTI and LLS pricing may not be indicative of future periods.

Natural gas liquids – Our net NGL sales volumes continue to grow due to development of our U.S. resource plays, increasing by 23 percent and 29 percent during the second quarter and first six months of 2014 compared to the same periods of 2013. The majority of our NGL volumes are sold at reference to Mont Belvieu prices and our 2014 average price realizations reflect the increases in this benchmark.

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. Average Henry Hub settlement prices for natural gas were 14 percent and 29 percent higher for the second quarter and first six months of 2014 than in the same periods of 2013.

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 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Average Price Realizations [a]				
Total Liquid Hydrocarbons (per bbl)				
Equatorial Guinea	$59.72	$54.09	$61.12	$60.58
United Kingdom	110.51	101.85	110.02	108.01
Libya	—	117.55	—	122.64
Total Liquid Hydrocarbons	75.41	93.62	75.48	96.65
Natural Gas (per mcf)				
Equatorial Guinea[b]	$0.24	$0.24	$0.24	$0.24
United Kingdom	8.04	10.23	9.07	10.78
Libya	—	4.65	5.45	4.86
Total Natural Gas	0.69	1.24	0.80	1.31
Benchmark				
Brent (Europe) crude oil (per bbl)	$109.70	$102.58	$108.93	$107.54

[a] Excludes gains or losses on derivative instruments.

[b] 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.

Liquid hydrocarbons – Our U.K. liquid hydrocarbon production is relatively sweet and is generally sold in relation to the Brent crude benchmark. Our liquid hydrocarbon production from Equatorial Guinea includes condensate and NGLs that receive lower prices than crude oil.

Natural gas – Our major international natural gas-producing regions are the U.K. and Equatorial Guinea. Natural gas prices in Europe have been considerably higher than in the U.S. in recent years. In the case of Equatorial Guinea, our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. The natural gas sales from Equatorial Guinea are at fixed prices; therefore, our reported average natural gas realized prices 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"). Comparing the same periods of 2014 and 2013, the WCS discount to WTI widened in the second quarter, increasing $0.93 per barrel; however, in the first six months, the WCS discount to WTI narrowed by $3.93 per barrel.

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.

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 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Average Price Realizations [a]				
Synthetic Crude Oil (per bbl)	$94.17	$89.39	$91.27	$84.31
Benchmark				
WTI crude oil (per bbl)	$102.99	$94.17	$100.84	$94.26
WCS crude oil (per bbl)[b]	$82.95	$75.06	$79.25	$68.74
AECO natural gas sales index (per mmbtu)[c]	$4.46	$3.45	$4.72	$3.31

[a] Excludes gains or losses on derivative instruments.

[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 summarized by segment in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Sales and other operating revenues, including related party				
North America E&P	$1,540	$1,284	$2,932	$2,499
International E&P	347	826	727	1,721
Oil Sands Mining	383	353	760	741
Segment sales and other operating revenues, including related party	$2,270	$2,463	$4,419	$4,961
Unrealized gain on crude oil derivative instruments	—	50	—	—
Sales and other operating revenues, including related party	$2,270	$2,513	$4,419	$4,961

North America E&P sales and other operating revenues increased 20 percent and 17 percent in the second quarter and first six months of 2014 from the comparable prior-year periods primarily due to higher liquid hydrocarbon net sales volumes from continued growth across our three U.S. resource plays, combined with higher average price realizations for all products.

The following tables display changes in North America E&P segment sales and other operating revenues by product. Refer to the preceding Operations and Market Conditions sections for additional detail related to our net sales volumes and average price realizations.

(In millions)	Three Months Ended June 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended June 30, 2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$1,144	$31	$228	$1,403
Natural gas	120	22	(9)	133
Realized gain on crude oil derivative instruments	17	(17)		—
Other sales	3			4
Total	$1,284			$1,540

(In millions)	Six Months Ended June 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Six Months Ended June 30, 2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$2,239	$11	$397	$2,647
Natural gas	239	60	(23)	276
Realized gain on crude oil derivative instruments	13	(13)		—
Other sales	8			9
Total	$2,499			$2,932

International E&P sales and other operating revenues decreased 58 percent in both the second quarter and first six months of 2014 from the comparable prior-year periods. The decreases were primarily due to lower liquid hydrocarbon net sales volumes, primarily in Libya as previously discussed, combined with lower average price realizations for both liquid hydrocarbons and natural gas.

The following tables display changes in International E&P segment sales and other operating revenues by product. Refer to the preceding Operations and Market Conditions sections for additional detail related to our net sales volumes and price realizations.

(In millions)	Three Months Ended June 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended June 30, 2014
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$761	$(73)	$(383) [(a)]	$305
Natural gas	52	(24)	2	30
Other sales	13			12
Total	$826			$347

[(a)] Includes a $480 million decrease related to Libya.

(In millions)	Six Months Ended June 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Six Months Ended June 30, 2014
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$1,580	$(178)	$(768) [(b)]	$634
Natural gas	116	(43)	(4)	69
Other sales	25			24
Total	$1,721			$727

[(b)] Includes an $871 million decrease related to Libya.

Oil Sands Mining sales and other operating revenues increased 8 percent and 3 percent in the second quarter and first six months of 2014 from the comparable prior-year periods. The increase in the second quarter of 2014 is primarily due to higher price realizations and increased net sales volumes as a result of a planned turnaround in the second quarter of 2013. The increase in the first six months of 2014 is primarily due to higher price realizations, partially offset by lower net sales volumes, as previously discussed.

The following tables display changes in OSM segment sales and other operating revenues by product. Refer to the preceding Operations and Market Conditions sections for additional detail related to our net sales volumes and average price realizations.

(In millions)	Three Months Ended June 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended June 30, 2014
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$348	$20	$9	$377
Other sales	5			6
Total	$353			$383

(In millions)	Six Months Ended June 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Six Months Ended June 30, 2014
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$714	$58	$(22)	$750
Other sales	27			10
Total	$741			$760

Unrealized gains and losses on crude oil derivative instruments are included in total sales and other operating revenues but are not allocated to the segments. In the second quarter of 2013, the net unrealized gain on crude oil derivative instruments was $50 million while unrealized gains and losses did not have a significant impact on the first six months of 2013. There were no crude oil derivative instruments in the second quarter and first six months of 2014.

Marketing revenues increased $121 million and $230 million in the second quarter and first six months of 2014 from the comparable prior-year periods, related primarily to North America E&P segment marketing activities, which serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. The volume of activity was higher due to market dynamics and higher prices for crude oil and natural gas in both periods.

Income from equity method investments increased $43 million and $62 million in the second quarter and first six months of 2014 from the comparable prior-year periods primarily due to higher LNG average price realizations and net sales volumes due to a turnaround in the second quarter of 2013.

Net gain (loss) on disposal of assets in the second quarter and first six months of 2014 primarily includes the loss on the sale of non-core acreage located in the far northwest portion of the Williston Basin. See Note 5 to the consolidated financial statements for further details on dispositions.

Production expenses increased $10 million in the second quarter of 2014 from the same quarter in 2013. North America E&P segment production expenses increased $22 million primarily related to higher net sales volumes in the U.S. resource plays. International E&P segment production expenses increased $16 million and included $5 million related to a turnaround at Brae in the U.K. during the second quarter of 2014. Lower sales volumes from Libya, rather than cost increases, contributed to the higher production expense rate (expense per barrel of oil equivalent or "boe") for the International E&P segment. OSM segment production expenses decreased $28 million in the second quarter of 2014, primarily because the year-ago quarter included higher costs associated with the planned turnaround.

In the first six months of 2014, production expenses increased $19 million compared to the same period of 2013. North America E&P segment production expenses increased $49 million primarily related to higher net sales volumes in the U.S. resource plays. International E&P segment production expenses increased $38 million due primarily to the discussed above and an $11 million charge for non-recurring riser repairs in Equatorial Guinea during the first quarter of 2014. Lower sales volumes from Libya, as discussed above, contributed to the higher production expense rate for the International E&P segment. OSM segment production expenses decreased $68 million in the first six months of 2014 due to the 2013 turnaround discussed above and lower contract services and contract labor costs in 2014.

The following table provides production expense rates for each segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
($ per boe)	2014	2013	2014	2013
Production Expense Rate				
North America E&P	$10.47	$10.62	$10.74	$10.49
International E&P	$8.87	$5.43	$8.82	$5.19
Oil Sands Mining [(a)]	$51.53	$57.62	$49.54	$51.52

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

Marketing costs increased $120 million and $229 million in the second quarter and first six months of 2014 from the comparable prior-year periods, consistent with the marketing revenues changes discussed above.

Exploration expenses were $364 million lower in the first six months of 2014 than in the comparable prior-year period. The first quarter of 2013 included $340 million in non-cash unproved property impairments on Eagle Ford leases that either expired or that we did not expect to drill or extend. The following table summarizes the components of exploration expenses:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Exploration Expenses				
Unproved property impairments	$60	$40	$101	$423
Dry well costs	53	50	55	71
Geological and geophysical	6	9	17	36
Other	26	26	45	52
Total exploration expenses	$145	$125	$218	$582

Depreciation, depletion and amortization ("DD&A") increased $54 million and $66 million in the second quarter and first six months of 2014 from the comparable prior-year periods. 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 changes in reserves and capitalized costs, can also cause changes to our DD&A.

Increased DD&A in the second quarter and first six months of 2014 primarily reflects the impact of higher North America E&P net sales volumes from our three U.S. resource plays; partially offset by lower International E&P segment sales volumes from Libya as previously discussed.

The International E&P segment DD&A rate increased in the second quarter and first six months of 2014 primarily due to increased amortization of capitalized asset retirement costs due to revisions to estimates of abandonment obligations in the U.K. at the end of the second quarter of 2013. The following table provides DD&A rates for each segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
($ per boe)	2014	2013	2014	2013
DD&A Rate				
North America E&P	$26.58	$26.74	$26.72	$26.78
International E&P	$6.64	$5.15	$6.45	$5.41
Oil Sands Mining	$11.78	$12.25	$11.74	$12.19

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 United States, which tend to increase or decrease in relation to sales volumes and revenue. With the increase in North America E&P revenues and net sales volumes, taxes other than income increased $16 million and $29 million in the second quarter and first six months of 2014 from the comparable prior-year periods. The following table summarizes the components of taxes other than income:

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	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Production and severance	$68	$54	$122	$101
Ad valorem	19	19	38	36
Other	22	20	44	38
Total	$109	$93	$204	$175

General and administrative expenses decreased $20 million in the second quarter of 2014 compared to the same period in 2013 primarily due to a lower pension settlement charge as well as lower employee related costs. Partial settlements of our U.S. pension plans resulted in charges of $8 million and $17 million in the second quarters of 2014 and 2013. The increase in the first six months of 2014 from the comparable prior-year period was $4 million due to higher pension settlements in 2014, nearly offset by lower employee related costs and less contract services. Partial settlements of our U.S. pension plans resulted in charges of $71 million and $17 million in the first six months of 2014 and 2013.

Net interest and other decreased $15 million in the first six months of 2014 compared to the same period in 2013 primarily due to a dividend received in the first quarter of 2014 from a mutual insurance company of which we are an owner.

Provision for income taxes decreased $412 million and $662 million in the second quarter and first six months of 2014 from the comparable prior-year periods primarily as a result of reduced pretax income in Libya. See Note 8 to the consolidated financial statements for discussion of the effective tax rate.

Discontinued operations are presented net of tax. See the preceding Operations section and Note 5 to the consolidated financial statements for financial information about discontinued operations.

Segment Income

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. Unrealized gains or losses on crude oil derivative instruments, certain impairments, gains or losses on dispositions or other items that affect comparability also are not allocated to operating segments.

The following table reconciles segment income to net income:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
North America E&P	$302	$221	$544	$162
International E&P	160	170	381	443
Oil Sands Mining	55	20	119	58
Segment income	517	411	1,044	663
Items not allocated to segments, net of income taxes	(157)	(170)	(286)	(264)
Income from continuing operations	360	241	758	399
Discontinued operations [(a)]	180	185	931	410
Net income	$540	$426	$1,689	$809

(a) We sold our Angola assets in the first quarter of 2014 and entered into an agreement to sell our Norway business in June 2014. The Angola and Norway businesses are reflected as discontinued operations in all periods presented.

North America E&P segment income increased $81 million and $382 million after-tax in the second quarter and first six months of 2014 compared to the same periods of 2013. The increases in both periods are primarily due to higher liquid hydrocarbon net sales volumes from the U.S. resource plays and higher price realizations, partially offset by higher production expenses and DD&A associated with the higher volumes. In addition, the six-month period of 2013 included the previously discussed non-cash unproved property impairments.

International E&P segment income decreased $10 million and $62 million after-tax in the second quarter and first six months of 2014 compared to the same periods of 2013. The decreases in both periods are primarily a result of the previously discussed lower net sales volumes in Libya and lower price realizations, partially offset by reduced taxes associated with the lower sales volumes. In addition, the second quarter of 2014 had higher exploration expenses due to dry wells, partially offset by higher earnings from our equity method LNG operations in Equatorial Guinea due to a turnaround in the second quarter of 2013.

Oil Sands Mining segment income increased $35 million and $61 million after-tax in the second quarter and first six months of 2014 from the comparable prior-year periods. The second quarter 2014 increase was primarily due to higher price realizations and lower production costs associated with a planned turnaround in the second quarter of 2013. The increase in the first six months of 2014 was primarily the result of higher price realizations and lower production costs partially offset by lower net sales volumes due to lower mine reliability and the planned 2013 turnaround as previously discussed.

Critical Accounting Estimates

There have been no changes to our critical accounting estimates subsequent to December 31, 2013.

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 for the six months ended June 30, 2014 and 2013:

	Six Months Ended June 30,	
(In millions)	2014	2013
Sources of cash and cash equivalents		
Continuing operations	$2,118	$1,922
Discontinued operations	440	474
Disposals of assets	2,232	333
Other	113	98
Total sources of cash and cash equivalents	$4,903	$2,827
Uses of cash and cash equivalents		
Additions to property, plant and equipment	$(2,230)	$(2,405)
Investing activities of discontinued operations	(233)	(271)
Purchases of common stock	(1,000)	—
Commercial paper, net	(135)	(200)
Debt repayments	(34)	(148)
Dividends paid	(260)	(241)
Other	(10)	—
Cash held for sale	(96)	—
Total uses of cash and cash equivalents	$(3,998)	$(3,265)

Disposals of assets in the first six months of 2014 primarily reflect the net proceeds from the sales of our interests in Angola Blocks 31 and 32. In the first six months of 2013, net proceeds were primarily related to the sales of our Alaska assets and our interests in the Neptune gas plant and the DJ Basin.

Additions to property, plant and equipment are our most significant use of cash and cash equivalents. The following table breaks-out capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows for the six months ended June 30, 2014 and 2013:

	Six Months Ended June 30,	
(In millions)	2014	2013
North America E&P	$1,969	$1,874
International E&P	220	194
Oil Sands Mining	123	143
Corporate	13	40
Total capital expenditures	2,325	2,251
Change in capital expenditure accrual	(95)	154
Additions to property, plant and equipment	$2,230	$2,405

Purchases of common stock are discussed in Note 17 to the consolidated financial statements.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, the issuance of notes, our committed revolving credit facility and sales of non-strategic assets. Our working capital requirements are supported by these sources and we may issue commercial paper backed by our $2.5 billion revolving credit facility to meet short-term cash requirements. 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 short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, share repurchase program and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

Credit Arrangements and Borrowings

In May 2014, we amended our $2.5 billion unsecured revolving credit facility which now matures in May 2019. See Note 15 to the consolidated financial statements for additional terms and rates. At June 30, 2014, 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, 2014, we had $6,430 million in long-term debt outstanding, $68 million of which is due within one year. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

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.

Pending Asset Disposal

In June 2014, we entered into an agreement to sell our Norway business in a transaction expected to close in the fourth quarter of 2014. The $2.1 billion of proceeds will be prioritized first toward organic growth, with the balance available for share repurchases and general corporate purposes. See Note 5 to the consolidated financial statements for additional discussion of the Norway disposal.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash and cash equivalents to total debt-plus-equity-minus-cash and cash equivalents) was 21 percent at June 30, 2014, compared to 25 percent at December 31, 2013.

(In millions)	June 30, 2014	December 31, 2013
Commercial paper	$—	$135
Long-term debt due within one year	68	68
Long-term debt	6,362	6,394
Total debt	$6,430	$6,597
Cash and cash equivalents	$1,169	$264
Equity	$19,868	$19,344
Calculation:		
Total debt	$6,430	$6,597
Minus cash and cash equivalents	1,169	264
Total debt minus cash and cash equivalents	$5,261	$6,333
Total debt	$6,430	$6,597
Plus equity	19,868	19,344
Minus cash and cash equivalents	1,169	264
Total debt plus equity minus cash and cash equivalents	$25,129	$25,677
Cash-adjusted debt-to-capital ratio	21 %	25 %

Capital Requirements

On July 30, 2014, our Board of Directors approved a dividend of 21 cents per share for the second quarter of 2014, an 11 percent increase over the previous quarter, payable September 10, 2014 to stockholders of record at the close of business on August 20, 2014.

As of June 30, 2014, we plan to make contributions of up to $52 million to our funded pension plans during the remainder of 2014.

In 2013, our Board of Directors increased the authorization for repurchases of our common stock by $1.2 billion, bringing the total authorized to $6.2 billion. As of June 30, 2014, we had repurchased a total of 121 million common shares at a cost of $4.7 billion, including 29 million shares at a cost of $1 billion in the first six months of 2014. The remaining share repurchase authorization as of June 30, 2014 is $1.5 billion. Purchases under the repurchase program may be in either open market transactions, including block purchases, or in privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program’s authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales, cash from available borrowings and market conditions.

Contractual Cash Obligations

As of June 30, 2014, our total contractual cash obligations were consistent with December 31, 2013.

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, 2013.

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, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included or incorporated by reference in this report, including without limitation statements regarding our operational, financial and growth strategies, planned capital expenditures and the impact thereof, growth activities and expectations, future drilling plans and expected timing, expected production, planned maintenance activities, enhanced completion designs, share repurchase program, operational outlook, future financial position, liquidity and capital resources, expected additions to our Oklahoma acreage position, the planned sale of our Norway business and the expected proceeds and timing thereof, and the plans and objectives of our management for our future operations, are forward-looking statements. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as “anticipates,” “believes,” “estimates,” “expects,” “targets,” “plans,” “projects,” “could,” “ “should,” “would” or similar words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including the level of supply or demand for liquid hydrocarbons and natural gas and the impact on the price of liquid hydrocarbons and natural gas;
- changes in political or economic conditions in key operating markets, including international markets;
- the amount of capital available for exploration and development;
- timing of commencing production from new wells;
- drilling rig availability;
- availability of materials and labor;

- the inability to obtain or delay in obtaining necessary government or third-party approvals and permits;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- changes in safety, health, environmental and other regulations;
- other geological, operating and economic considerations; and

- other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2013, and those set forth from time to time in our filings with the Securities and Exchange Commission.

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

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 2013 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.

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of June 30, 2014 is provided in the following table.

(In millions)	Fair Value		Incremental Change in Fair Value
Financial assets (liabilities): [a]			
Interest rate swap agreements	$11	[b]	$3
Long-term debt, including amounts due within one year	$(7,133)	[b][c]	$(215)

[a] Fair values of cash and cash equivalents, receivables, commercial paper, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

[b] Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.

[c] Excludes capital leases.

The incremental change in fair value of our foreign currency derivative contracts of a hypothetical 10 percent change in exchange rates at June 30, 2014 would be $47 million.

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 Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our company's design and operation of disclosure controls and procedures were effective as of June 30, 2014.

During the second quarter of 2014, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2014	2013	2014	2013
Segment Income				
North America E&P	$302	$221	$544	$162
International E&P	160	170	381	443
Oil Sands Mining	55	20	119	58
Segment income	517	411	1,044	663
Items not allocated to segments, net of income taxes	(157)	(170)	(286)	(264)
Income from continuing operations	360	241	758	399
Discontinued operations [(a)]	180	185	931	410
Net income	$540	$426	$1,689	$809
Capital Expenditures [(b)]				
North America E&P	$1,102	$904	$1,969	$1,874
International E&P	115	107	220	194
Oil Sands Mining	55	98	123	143
Corporate	10	10	13	40
Discontinued operations [(a)]	141	138	251	276
Total	$1,423	$1,257	$2,576	$2,527
Exploration Expenses				
North America E&P	$82	$76	$139	$511
International E&P	63	49	79	71
Total	$145	$125	$218	$582

(a) We sold our Angola assets in the first quarter of 2014 and entered into an agreement to sell our Norway business in June 2014. The Angola and Norway businesses are reflected as discontinued operations in all periods presented.

(b) Capital expenditures include changes in accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Net Sales Volumes	2014	2013	2014	2013
North America E&P				
Crude Oil and Condensate (mbbld)				
Bakken	44	35	41	34
Eagle Ford	67	50	65	48
Oklahoma resource basins	2	1	2	1
Other North America	38	40	36	41
Total Crude Oil and Condensate	151	126	144	124
Natural Gas Liquids (mbbld)				
Bakken	3	2	2	2
Eagle Ford	16	14	16	13
Oklahoma resource basins	6	4	5	4
Other North America	2	2	4	2
Total Natural Gas Liquids	27	22	27	21
Total Liquid Hydrocarbons (mbbld)				
Bakken	47	37	43	36
Eagle Ford	83	64	81	61
Oklahoma resource basins	8	5	7	5
Other North America	40	42	40	43
Total Liquid Hydrocarbons	178	148	171	145
Natural Gas (mmcfd)				
Bakken	18	12	17	13
Eagle Ford	111	99	109	91
Oklahoma resource basins	61	48	58	49
Other North America	104	157	113	175
Total Natural Gas	294	316	297	328
Total North America E&P (mboed)	227	201	220	200

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Net Sales Volumes	2014	2013	2014	2013
International E&P				
Total Liquid Hydrocarbons (mbbld)				
Equatorial Guinea	31	30	33	34
United Kingdom	13	14	13	17
Libya	—	45	—	39
Total Liquid Hydrocarbons	44	89	46	90
Natural Gas (mmcfd)				
Equatorial Guinea	446	401	441	424
United Kingdom[c]	28	36	29	38
Libya	—	24	1	25
Total Natural Gas	474	461	471	487
Total International E&P (mboed)	123	166	125	171
Oil Sands Mining				
Synthetic Crude Oil (mbbld)[d]	44	43	45	47
Total Continuing Operations (mboed)	394	410	390	418
Discontinued Operations - Angola (mboed)[a]	—	9	3	9
Discontinued Operations - Norway (mboed)[a]	70	87	70	88
Total Company (mboed)	464	506	463	515
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	6,624	5,820	6,601	6,301
Methanol (mtd)	980	973	1,066	1,191

(c) Includes natural gas acquired for injection and subsequent resale of 5 mmcfd and 8 mmcfd for the second quarters of 2014 and 2013, and 6 mmcfd and 10 mmcfd for the first six months of 2014 and 2013.

(d) Includes blendstocks.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Average Price Realizations [e]	2014	2013	2014	2013
North America E&P				
Crude Oil and Condensate (per bbl)				
Bakken	$93.08	$88.65	$91.43	$89.89
Eagle Ford	99.08	99.40	97.65	101.50
Oklahoma resource basins	101.12	90.51	98.05	90.32
Other North America	93.45	91.32	91.40	89.31
Total Crude Oil and Condensate	95.95	93.75	94.30	94.20
Natural Gas Liquids (per bbl)				
Bakken	$45.13	$35.92	$51.04	$38.42
Eagle Ford	30.20	28.09	33.76	28.12
Oklahoma resource basins	33.04	27.99	38.21	34.77
Other North America	54.13	51.05	57.65	53.71
Total Natural Gas Liquids	34.80	31.72	38.75	33.51
Total Liquid Hydrocarbons (per bbl) [f]				
Bakken	$90.47	$85.96	$89.16	$87.23
Eagle Ford	85.36	83.90	84.78	85.88
Oklahoma resource basins	52.00	47.05	55.04	49.88
Other North America	90.45	88.64	88.97	87.02
Total Liquid Hydrocarbons	86.43	84.51	85.65	85.30
Natural Gas (per mcf)				
Bakken	$4.12	$4.47	$6.14	$4.02
Eagle Ford	4.76	4.17	4.83	3.80
Oklahoma resource basins	4.57	4.71	5.01	4.13
Other North America	5.65	4.01	5.35	4.11
Total Natural Gas	5.00	4.19	5.14	4.02

[e] Excludes gains or losses on derivative instruments.

[f] Inclusion of realized gains on crude oil derivative instruments would have increased average liquid hydrocarbon price realizations by $1.26 and $0.50 per bbl for the second quarter and first six months of 2013. There were no crude oil derivative instruments for the second quarter and first six months of 2014.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Average Price Realizations [e]	2014	2013	2014	2013
International E&P				
Total Liquid Hydrocarbons (per bbl)				
Equatorial Guinea	$59.72	$54.09	$61.12	$60.58
United Kingdom	110.51	101.85	110.02	108.01
Libya	—	117.55	—	122.64
Total Liquid Hydrocarbons	75.41	93.62	75.48	96.65
Natural Gas (per mcf)				
Equatorial Guinea[g]	$0.24	$0.24	$0.24	$0.24
United Kingdom	8.04	10.23	9.07	10.78
Libya	—	4.65	5.45	4.86
Total Natural Gas	0.69	1.24	0.80	1.31
Oil Sands Mining				
Synthetic Crude Oil (per bbl)	$94.17	$89.39	$91.27	$84.31
Discontinued Operations - Angola (per boe)[a]	—	$100.30	$99.82	$103.17
Discontinued Operations - Norway (per boe)[a]	$108.11	$103.73	$108.09	$108.74

[g] 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. The discussion of such risks and uncertainties may be found under Item 1A. Risk Factors in our 2013 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, 2014, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934.

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased [a][b]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[c]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[c]
04/01/14 - 04/30/14	8,297,968	$35.64	8,233,581	$1,655,706,060
05/01/14 - 05/31/14	4,283,727	$36.34	4,276,263	$1,500,285,529
06/01/14 - 06/30/14	29,876	$37.83	—	$1,500,285,529
Total	12,611,571	$35.88	12,509,844	

(a) 77,436 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In June 2014, 24,291 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the "Dividend Reinvestment Plan") by the administrator of the Dividend Reinvestment Plan. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon Oil.

(c) As of June 30, 2014, we had repurchased 121 million common shares at a cost of $4.7 billion, which includes transaction fees and commissions that are not reported in the table above. Of this total, 13 million shares were acquired at a cost of $449 million during the second quarter of 2014.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

The following exhibits are filed as a part of this report:

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
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	001-05153		
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	10-Q	3.1	8/8/2013	001-05153		
3.2	Amended By-Laws of Marathon Oil Corporation effective February 25, 2014	10-K	3.2	2/28/2014	001-05153		
3.3	Specimen of Common Stock Certificate	10-K	3.3	2/28/2014	001-05153		
4.2	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 percent of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request.	10-K	4.2	2/28/2014	001-05153		
10.1	Credit Agreement, dated as of May 28, 2014, among Marathon Oil Corporation, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions named therein.	8-K	4.1	06/02/14	001-05153		
12.1	Computation of Ratio of Earnings to Fixed Charges.					X	

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.	X
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.	X
32.1	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.	X
32.2	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.	X
101.INS	XBRL Instance Document.	X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
101.SCH	XBRL Taxonomy Extension Schema.					X	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase.					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.					X	

++ Marathon Oil agrees to furnish supplementally a copy of any omitted schedule to the SEC upon request.

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 5, 2014		MARATHON OIL CORPORATION
	By:	
		John R. Sult
		Executive Vice President and Chief Financial Officer

Exhibit Index

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12.1	Computation of Ratio of Earnings to Fixed Charges.					X	
31.1						X	

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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.					X	

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