MARATHON OIL CORP
Form 10-Q
November 04, 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 September 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	25-0996816
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Street, Houston, TX 77056-2723
(Address of principal executive offices)

(713) 629-6600
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes R No £

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

There were 674,897,005 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2014.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended September 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 September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2014	2013	2014	2013
Revenues and other income:				
Sales and other operating revenues, including related party	$2,316	$2,334	$6,735	$7,295
Marketing revenues	554	666	1,713	1,595
Income from equity method investments	89	114	346	309
Net loss on disposal of assets	(3)	(6)	(88)	(4)
Other income	15	19	55	38
Total revenues and other income	2,971	3,127	8,761	9,233
Costs and expenses:				
Production	593	540	1,697	1,625
Marketing, including purchases from related parties	554	663	1,710	1,590
Other operating	99	115	303	283
Exploration	96	83	314	665
Depreciation, depletion and amortization	737	657	2,060	1,914
Impairments	109	11	130	49
Taxes other than income	115	89	319	264
General and administrative	160	143	486	465
Total costs and expenses	2,463	2,301	7,019	6,855
Income from operations	508	826	1,742	2,378
Net interest and other	(55)	(71)	(180)	(211)
Income from continuing operations before income taxes	453	755	1,562	2,167
Provision for income taxes	149	359	500	1,372
Income from continuing operations	304	396	1,062	795
Discontinued operations	127	173	1,058	583
Net income	$431	$569	$2,120	$1,378
Per basic share:				
Income from continuing operations	$0.45	$0.56	$1.56	$1.13
Discontinued operations	$0.19	$0.24	$1.55	$0.82
Net income	$0.64	$0.80	$3.11	$1.95
Per diluted share:				
Income from continuing operations	$0.45	$0.56	$1.55	$1.12
Discontinued operations	$0.19	$0.24	$1.55	$0.82
Net income	$0.64	$0.80	$3.10	$1.94
Dividends per share	$0.21	$0.19	$0.59	$0.53
Weighted average common shares outstanding:				
Basic	675	707	681	708
Diluted	678	711	684	712

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
Net income	$431	$569	$2,120	$1,378
Other comprehensive income (loss)				
Postretirement and postemployment plans				
Change in actuarial loss and other	3	34	(40)	180
Income tax benefit (provision)	(2)	(13)	13	(67)
Postretirement and postemployment plans, net of tax	1	21	(27)	113
Foreign currency translation and other				
Unrealized gain (loss)	—	1	1	(3)
Income tax benefit (provision)	—	—	(1)	1
Foreign currency translation and other, net of tax	—	1	—	(2)
Other comprehensive income (loss)	1	22	(27)	111
Comprehensive income	$432	$591	$2,093	$1,489

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	September 30, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$761	$264
Receivables	2,048	2,134
Inventories	379	364
Other current assets	143	172
Current assets held for sale	873	41
Total current assets	4,204	2,975
Equity method investments	1,103	1,201
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,024 and $21,895	28,658	28,145
Goodwill	457	499
Other noncurrent assets	988	1,153
Noncurrent assets held for sale	1,290	1,647
Total assets	$36,700	$35,620
Liabilities		
Current liabilities:		
Commercial paper	$—	$135
Accounts payable	2,430	2,206
Payroll and benefits payable	149	240
Accrued taxes	181	1,445
Other current liabilities	184	214
Long-term debt due within one year	68	68
Current liabilities held for sale	1,164	25
Total current liabilities	4,176	4,333
Long-term debt	6,355	6,394
Deferred tax liabilities	2,570	2,492
Defined benefit postretirement plan obligations	611	604
Asset retirement obligations	2,003	2,009
Deferred credits and other liabilities	405	401
Noncurrent liabilities held for sale	354	43
Total liabilities	16,474	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 – 95 million and 73 million shares	(3,644)	(2,903)
Additional paid-in capital	6,523	6,592
Retained earnings	16,854	15,135
Accumulated other comprehensive loss	(277)	(250)

Total stockholders' equity	20,226	19,344
Total liabilities and stockholders' equity	$36,700	$35,620

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30,	
(In millions)	2014	2013
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$2,120	$1,378
Adjustments to reconcile net income to net cash provided by operating activities:		
Discontinued operations	(1,058)	(583)
Deferred income taxes	337	(2)
Depreciation, depletion and amortization	2,060	1,914
Impairments	130	49
Pension and other postretirement benefits, net	(27)	41
Exploratory dry well costs and unproved property impairments	220	553
Net loss on disposal of assets	88	4
Equity method investments, net	51	12
Changes in:		
Current receivables	(270)	(133)
Inventories	(32)	(11)
Current accounts payable and accrued liabilities	(115)	(20)
All other operating, net	(28)	98
Net cash provided by continuing operations	3,476	3,300
Net cash provided by discontinued operations	856	741
Net cash provided by operating activities	4,332	4,041
Investing activities:		
Acquisitions, net of cash acquired	(12)	(74)
Additions to property, plant and equipment	(3,639)	(3,383)
Disposal of assets	2,237	402
Investments - return of capital	46	45
Investing activities of discontinued operations	(356)	(435)
All other investing, net	(24)	34
Net cash used in investing activities	(1,748)	(3,411)
Financing activities:		
Commercial paper, net	(135)	—
Debt repayments	(34)	(148)
Purchases of common stock	(1,000)	(500)
Dividends paid	(401)	(376)
All other financing, net	150	70
Net cash used in financing activities	(1,420)	(954)
Effect of exchange rate on cash and cash equivalents:		
Continuing operations	(1)	(3)
Discontinued operations	(11)	(3)
Cash held for sale	(655)	—
Net increase (decrease) in cash and cash equivalents	497	(330)
Cash and cash equivalents at beginning of period	264	684
Cash and cash equivalents at end of period	$761	$354

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 ("U.S. GAAP") for complete financial statements.

As the result of the sale of our Angola assets in the first quarter of 2014 and the sale our Norway business, which closed October 15, 2014 (see Note 6), these 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 are presented as held for sale in the consolidated balance sheets as of December 31, 2013 for our Angola business and September 30, 2014 for our Norway business.

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 third quarter and first nine months of 2014 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Not Yet Adopted

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

In May 2014, the FASB issued an update that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively, and improves guidance for multiple-element arrangements. This standard is effective for us in the first quarter of 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 did not elect early adoption of this amendment and do not expect its future adoption to have a significant impact 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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 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.

3. Variable Interest Entity

The owners of the Athabasca Oil Sands Project, 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 September 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 $586 million as of September 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 2 million and 4 million stock options for the third quarters of 2014 and 2013 and 4 million and 5 million stock options for the first nine months of 2014 and 2013 as they were antidilutive.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2014	2013	2014	2013
Income from continuing operations	$304	$396	$1,062	$795
Discontinued operations	127	173	1,058	583
Net income	$431	$569	$2,120	$1,378
Weighted average common shares outstanding	675	707	681	708
Effect of dilutive securities	3	4	3	4
Weighted average common shares, including dilutive effect	678	711	684	712
Per basic share:				
Income from continuing operations	$0.45	$0.56	$1.56	$1.13
Discontinued operations	$0.19	$0.24	$1.55	$0.82
Net income	$0.64	$0.80	$3.11	$1.95
Per diluted share:				
Income from continuing operations	$0.45	$0.56	$1.55	$1.12
Discontinued operations	$0.19	$0.24	$1.55	$0.82
Net income	$0.64	$0.80	$3.10	$1.94

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

5. Acquisitions
2014 - North America Exploration and Production ("E&P") Segment
In an asset acquisition that closed August 2014, we added acreage to our Oklahoma resource position at a cost of approximately $80 million before final settlement adjustments.
2013 - North America E&P Segment
In July 2013, we acquired additional acreage in the Eagle Ford in a transaction valued at $97 million, including a carried interest of $23 million which was fully satisfied as of September 30, 2014. The pro forma impact of this transaction is not material to our consolidated statements of income for any periods presented.
The transaction was accounted for as a business combination with the fair values of assets acquired and liabilities assumed measured primarily using an income approach, specifically utilizing a discounted cash flow model. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices, assumptions regarding future operating and development costs and a discount rate of approximately 10 percent. The entire up-front cash consideration of $74 million was allocated to property, plant and equipment at the acquisition date.
6. Dispositions
2014 - International 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. The transaction closed on October 15, 2014. After adjustment for debt, net working capital and interest on the net purchase price, we received proceeds of approximately $2.1 billion and expect to record a pretax gain of approximately $1.4 billion in the fourth quarter of 2014.
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 September 30,		Nine Months Ended September 30,		
(In millions)	2014	2013	2014		2013
Revenues applicable to discontinued operations	$528	$699	$1,901		$2,431
Pretax income from discontinued operations	$487	$523	$1,617		$1,945
After-tax income from discontinued operations	$127	$122	$449	(a)	$502

(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 September 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. Included in the after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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 September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
Revenues applicable to discontinued operations	$—	$89	$58	$254
Pretax income from discontinued operations, before gain	$—	$78	$51	$156
Pretax gain on disposition of discontinued operations	$—	$—	$470	$—
After-tax income from discontinued operations	$—	$51	$609 [a]	$81

[a] Includes an after-tax gain on disposition of discontinued operations of $576 million.

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.

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 on this sale 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.

7. 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 our Norway business on October 15, 2014. The Angola and Norway businesses are reflected as discontinued operations and are excluded from the International E&P segment in all periods presented.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended September 30, 2014					
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
Sales and other operating revenues	$1,586	$273	$457	$—		$2,316
Marketing revenues	506	46	2	—		554
Total revenues	2,092	319	459	—		2,870
Income from equity method investments	—	89	—	—		89
Net gain (loss) on disposal of assets and other income	(1)	12	—	1		12
Less:						
Production expenses	233	108	252	—		593
Marketing costs	507	45	2	—		554
Exploration expenses	55	41	—	—		96
Depreciation, depletion and amortization	609	55	62	11		737
Impairments	—	—	—	109	(c)	109
Other expenses (a)	118	26	14	101	(d)	259
Taxes other than income	109	—	5	1		115
Net interest and other	—	—	—	55		55
Income tax provision (benefit)	168	39	31	(89)		149
Segment income/Income from continuing operations	$292	$106	$93	$(187)		$304
Capital expenditures (b)	$1,277	$166	$49	$16		$1,508

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Proved property impairments (see Note 13).
(d) Includes pension settlement loss of $22 million.

	Three Months Ended September 30, 2013					
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments		Total
Sales and other operating revenues	$1,321	$611	$463	$(61)	(c)	$2,334
Marketing revenues	607	56	3	—		666
Total revenues	1,928	667	466	(61)		3,000
Income from equity method investments	—	114	—	—		114
Net gain (loss) on disposal of assets and other income	9	7	2	(5)		13
Less:						
Production expenses	205	108	227	—		540
Marketing costs	605	55	3	—		663
Exploration expenses	48	35	—	—		83
Depreciation, depletion and amortization	490	116	54	(3)		657
Impairments	11	—	—	—		11
Other expenses (a)	111	35	38	74	(d)	258
Taxes other than income	82	—	5	2		89
Net interest and other	—	—	—	71		71
Income tax provision (benefit)	143	247	35	(66)		359
Segment income/Income from continuing operations	$242	$192	$106	$(144)		$396
Capital expenditures (b)	$832	$120	$66	$7		$1,025

(a)Includes other operating expenses and general and administrative expenses.
(b)Includes accruals.

(c)Unrealized loss on crude oil derivative instruments.
(d)Includes pension settlement loss of $15 million.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30, 2014				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$4,518	$1,000	$1,217	$—	$6,735
Marketing revenues	1,486	177	50	—	1,713
Total revenues	6,004	1,177	1,267	—	8,448
Income from equity method investments	—	346	—	—	346
Net gain (loss) on disposal of assets and other income	17	44	3	(97) [(c)]	(33)
Less:					
Production expenses	661	307	729	—	1,697
Marketing costs	1,484	176	50	—	1,710
Exploration expenses	194	120	—	—	314
Depreciation, depletion and amortization	1,674	201	152	33	2,060
Impairments	21	—	—	109 [(d)]	130
Other expenses [(a)]	354	98	40	297 [(e)]	789
Taxes other than income	301	—	16	2	319
Net interest and other	—	—	—	180	180
Income tax provision (benefit)	496	178	71	(245)	500
Segment income/Income from continuing operations	$836	$487	$212	$(473)	$1,062
Capital expenditures [(b)]	$3,246	$386	$172	$29	$3,833

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Primarily related to the sale of non-core acreage located in the far northwest portion of the Williston Basin (see Note 6).
(d) Proved property impairments (see Note 13).
(e) Includes pension settlement loss of $93 million.

	Nine Months Ended September 30, 2013				
(In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$3,820	$2,332	$1,204	$(61) [(c)]	$7,295
Marketing revenues	1,391	192	12	—	1,595
Total revenues	5,211	2,524	1,216	(61)	8,890
Income from equity method investments	—	309	—	—	309
Net gain (loss) on disposal of assets and other income	15	30	5	(16)	34
Less:					
Production expenses	584	269	772	—	1,625
Marketing costs	1,390	188	12	—	1,590
Exploration expenses	559	106	—	—	665
Depreciation, depletion and amortization	1,458	284	154	18	1,914
Impairments	34	—	—	15 [(d)]	49
Other expenses [(a)]	311	99	48	290 [(e)]	748
Taxes other than income	244	—	16	4	264
Net interest and other	—	—	—	211	211
Income tax provision (benefit)	242	1,282	55	(207)	1,372

Segment income/Income from continuing operations	$404	$635	$164	$(408)	$795
Capital expenditures [b]	$2,706	$314	$209	$47	$3,276

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized loss on crude oil derivative instruments.
[d] Proved property impairments (see Note 13).
[e] Includes pension settlement loss of $32 million.

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8. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Service cost	$12	$12	$—	$1
Interest cost	15	16	4	3
Expected return on plan assets	(16)	(17)	—	—
Amortization:				
– prior service cost (credit)	1	2	(1)	(2)
– actuarial loss	7	9	—	—
Net settlement loss[(a)]	22	15	—	—
Net periodic benefit cost	$41	$37	$3	$2

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Service cost	$35	$38	$2	$3
Interest cost	46	47	10	9
Expected return on plan assets	(48)	(50)	—	—
Amortization:				
– prior service cost (credit)	4	5	(3)	(5)
– actuarial loss	23	38	—	—
Net settlement loss[(a)]	93	32	—	—
Net periodic benefit cost	$153	$110	$9	$7

(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 nine months of 2014 and 2013, we recorded the effects of partial settlements of our U.S. pension plans and we remeasured the plans' assets and liabilities as of the applicable balance sheet dates. As a result, we recognized a pretax increase of $10 million and a pretax decrease of $22 million in actuarial losses in other comprehensive income for the third quarter and first nine months of 2014 and a pretax decrease of $24 million and $163 million in actuarial losses in other comprehensive income for the third quarter and first nine months of 2013.

During the first nine months of 2014, we made contributions of $94 million to our funded pension plans. We expect to make additional contributions up to an estimated $24 million to our funded pension plans over the remainder of 2014. Current benefit payments related to unfunded pension plans were $83 million, and payments related to other postretirement benefit plans were $11 million during the first nine months of 2014.

9. Income Taxes

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

Our effective income tax rates on continuing operations for the first nine months of 2014 and 2013 were 32 percent and 63 percent. The decrease in the effective tax rate on continuing operations in the first nine 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.

The tax provision (benefit) applicable to Libyan ordinary income (loss) was recorded as a discrete item in the first nine months of 2014 and 2013. Excluding Libya, the effective tax rates on continuing operations would be 32 percent and 36 percent for the first nine 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

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scenarios in the worldwide annual effective tax rate calculation demonstrates significant variability. Thus, for the first nine months of 2014 and 2013, estimated annual effective tax rates were calculated excluding Libya and applied to consolidated ordinary income.

In the second quarter of 2014, we 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 $994 million at September 30, 2014. If such income were not permanently reinvested, income tax expense of approximately $348 million would be recorded, not including potential utilization of foreign tax credits.

10. Inventories

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

(In millions)	September 30, 2014	December 31, 2013
Liquid hydrocarbons, natural gas and bitumen	$80	$55
Supplies and other items	299	309
Inventories, at cost	$379	$364

11. Property, Plant and Equipment

(In millions)	September 30, 2014	December 31, 2013
North America E&P	$16,298	$14,973
International E&P [(a)]	2,754	3,590
Oil Sands Mining	9,486	9,447
Corporate	120	135
Net property, plant and equipment	$28,658	$28,145

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

In the third quarter of 2013, our production in Libya was interrupted by third-party labor strikes at the port facilities, which later resulted in a blockade of the Es Sider terminal from which we export oil. In July 2014, Libya's National Oil Corporation rescinded force majeure associated with these third-party labor strikes at the Es Sider terminal. Our first 2014 lifting occurred in August, and was sourced from existing inventory at the terminal. Production from the Waha concessions resumed in August 2014; however, considerable uncertainty remains around future production and sales levels. As of September 30, 2014, our net property, plant and equipment investment in Libya is approximately $771 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 $155 million as of September 30, 2014 (including $29 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 $126 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 $39 million due to the commencement of drilling at the Boyla development and sanction of the Viper project offshore Norway, partially offset by an increase of $66 million for Diaba License G4-223 offshore Gabon where the Diaman-1B well reached total depth in the third quarter of 2013. We are analyzing new 3D seismic, integrated with existing technical data, in order to finalize the next steps in the exploration program on the Diaba License.

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12. Asset Retirement Obligations

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

(In millions)	
Beginning balance[(a)]	$2,096
Incurred, including acquisitions	39
Settled, including dispositions	(110)
Accretion expense (included in depreciation, depletion and amortization)	87
Revisions to previous estimates[(b)]	231
Held for sale	(309)
Ending balance[(a)]	$2,034

(a) Includes asset retirement obligations of $87 million and $31 million classified as short-term at December 31, 2013 and September 30, 2014.

(b) Estimated abandonment and other costs increased for Gulf of Mexico and U.K. assets.

13. Fair Value Measurements

Fair Values - Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of September 30, 2014 and December 31, 2013 by fair value hierarchy level.

	September 30, 2014			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$—	$5	$—	$5
Derivative instruments, assets	$—	$5	$—	$5
Derivative instruments, liabilities				
Foreign currency	$—	$17	$—	$17
Derivative instruments, liabilities	$—	$17	$—	$17

	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.

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

	Three Months Ended September 30,			
	2014		2013	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$43	$109	$5	$11

	Nine Months Ended September 30,			
	2014		2013	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$43	$130	$5	$49

All long-lived assets held for use that were impaired in the first nine months of 2014 and 2013 were held by our North America E&P segment. The fair values of each were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement 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.
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 nine months of 2014, we recorded additional impairments of $30 million at Ozona as a result of estimated abandonment cost revisions.
In the third quarter of 2014, impairments of $53 million were recorded to certain other Gulf of Mexico properties, as a result of estimated abandonment cost and other revisions, to an aggregate fair value of $19 million.
Also in the third quarter of 2014, two additional fields were impaired a total of $47 million to an aggregate fair value of $24 million primarily due to lower forecasted commodity prices.
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 nine months of 2013 were a result of reduced drilling expectations, reductions of estimated reserves or declining commodity prices.
Crude oil prices began declining in the third quarter of 2014 and continued to decrease in October 2014. A period of sustained low commodity prices could result in additional non-cash impairment charges related to our assets in future periods.
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.

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

	September 30, 2014		December 31, 2013	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$194	$189	$154	$147
Total financial assets	194	189	154	147
Financial liabilities				
Other current liabilities	13	13	13	13
Long-term debt, including current portion [(a)]	7,057	6,394	6,922	6,427
Deferred credits and other liabilities	94	150	149	147
Total financial liabilities	$7,164	$6,557	$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. Most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

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

14. Derivatives

For further information regarding the fair value measurement of derivative instruments, see Note 13. All of our interest rate 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 September 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 September 30, 2014 and December 31, 2013.

	September 30, 2014			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$5	$—	$5	Other noncurrent assets
Total Designated Hedges	$5	$—	$5	

	September 30, 2014			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$—	$17	$17	Current liabilities held for sale
Total Designated Hedges	$—	$17	$17	

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	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	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 September 30, 2014 and December 31, 2013, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

	September 30, 2014		December 31, 2013	
Maturity Dates	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate
October 2, 2017	$600	4.64 %	$600	4.65 %
March 15, 2018	$300	4.49 %	$300	4.50 %

As of September 30, 2014 and December 31, 2013, our foreign currency forwards had an aggregate notional amount of 2,246 million and 2,387 million Norwegian Kroner at weighted average forward rates of 6.149 and 6.060. These forwards hedge the current Norwegian tax liability of the subsidiary that holds our Norway business. Those outstanding at September 30, 2014 have settlement dates through February 2015 and were transfered to the purchaser of our Norway business upon closing of the sale on October 15, 2014.

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

		Gain (Loss)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2014	2013	2014	2013
Derivative					
Interest rate	Net interest and other	$(6)	$5	$(3)	$(9)
Foreign currency	Discontinued operations	$(18)	$5	$(29)	$(41)
Hedged Item					
Long-term debt	Net interest and other	$6	$(5)	$3	$9
Accrued taxes	Discontinued operations	$18	$(5)	$29	$41

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 losses of $86 million and $73 million in the third quarter and first nine months of 2013. There were no crude oil derivatives in the third quarter and first nine months of 2014.

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15. 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 nine 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	1,935,888	$34.96
Options Exercised/Stock Vested	(5,882,065)	$23.45	(1,557,101)	$30.06
Canceled	(559,254)	$33.97	(448,358)	$32.02
Outstanding at September 30, 2014	13,598,991	$29.67	3,962,317	$34.00

[(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 nine months of 2014, we granted 221,491 stock-based performance units to certain officers. The grant date fair value per unit was $34.28.

16. Debt

As of September 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"), and extended 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.

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.

17. 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 September 30,		Nine Months Ended September 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	$(7)	$(9)	$(23)	$(38)	General and administrative
Net settlement loss	(22)	(15)	(93)	(32)	General and administrative
	(29)	(24)	(116)	(70)	Income from operations

	10	9	38	26	Provision for income taxes
Other insignificant, net of tax	—	—	(1)	(1)	
Total reclassifications	$(19)	$(15)	$(79)	$(45)	Income from continuing operations

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18. Stockholders' Equity

During the first nine months of 2014, we acquired 29 million common shares at a cost of $1 billion under our share repurchase program.

19. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
(In millions)	2014	2013
Net cash provided by operating activities:		
Interest paid (net of amounts capitalized)	$201	$216
Income taxes paid to taxing authorities [a]	1,514	3,218
Commercial paper, net:		
Issuances	$2,285	$4,975
Repayments	(2,420)	(4,975)
Commercial paper, net	(135)	—
Noncash investing activities, related to continuing operations:		
Asset retirement costs capitalized	$240	$309
Change in capital expenditure accrual	194	(107)
Asset retirement obligations assumed by buyer	52	92
Receivable for disposal of assets	44	—

(a) Income taxes paid to taxing authorities included $1,195 million and $1,690 million related to discontinued operations in the first nine months of 2014 and 2013.

20. 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 September 30, 2014, Marathon's contractual commitments to acquire property, plant and equipment were $1,051 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; 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 6 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 our Norway business on October 15, 2014. Assets and liabilities are presented as held for sale in the consolidated balance sheets as of December 31, 2013 for our Angola business and September 30, 2014 for our Norway business.

Executive Summary

Our net sales volumes from continuing operations for the third quarter and first nine months of 2014 averaged 417 thousand barrels of oil equivalent per day ("mboed") and 400 mboed compared to 403 mboed and 412 mboed for the third quarter and first nine months of 2013. As we had only one oil lifting from Libya in the third quarter and first nine months of 2014, a more representative comparison is net sales volumes from continuing operations excluding Libya. Excluding Libya, our net sales volumes from continuing operations increased 8 percent and 6 percent in the third quarter and first nine 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, partially offset by decreases from the U.K. and Equatorial Guinea. Net sales volumes related to the Angola and Norway discontinued operations for the third quarter and first nine months of 2014 averaged 58 mboed and 68 mboed compared to 77 mboed and 90 mboed for the third quarter and first nine months of 2013, ranging from 12 to 18 percent of total company net sales volumes in those periods.

Income from continuing operations per diluted share was $0.45 for the third quarter of 2014, a decrease of 20 percent over the same 2013 period, as a result of lower income from our International E&P segment driven primarily by lower net sales volumes combined with lower liquid hydrocarbon price realizations across all segments. In the first nine months of 2014, income from continuing operations per diluted share increased by 38 percent from the comparable 2013 period to $1.56, reflecting higher income from our North America E&P and Oil Sands Mining segments driven primarily by continued growth in net sales volumes from our U.S. resource plays partially offset by lower commodity prices. This increase in the first nine months of 2014 also reflects the $0.84 per diluted share after-tax gain on the sale of our Angola assets in the first quarter of 2014 and the $0.48 per diluted share after-tax non-cash charge for 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 third quarter of 2014, notable activities were:

- Increased average net sales volumes from the three U.S. resource plays to 192 mboed, up 43 percent from same quarter of last year
- Continued strong pace in the Eagle Ford with 87 gross operated wells to sales, up 14 percent from the second quarter of 2014
- Eight gross operated Austin Chalk wells brought to sales during the quarter, all within previously delineated acreage; 16 additional wells being drilled, completed or awaiting first production
- Nineteen gross operated Bakken wells brought to sales, of which eight are piloting enhanced completions
- Incremental drilling rig added in the Bakken as of late September to provide additional capacity for high-density spacing and enhanced completion pilots
- Six gross operated wells brought to sales in the Oklahoma Resource Basins, of which four were in the South Central Oklahoma Oil Province ("SCOOP") and two in the Southern Mississippi Trend
- Began drilling the operated Key Largo exploration well in the Gulf of Mexico
- Brought two successful South Brae infill wells online in the U.K. North Sea
- Recorded 96 percent average operational availability for operated assets

Significant fourth quarter activity through November 4, 2014 includes:

- Closed sale of our Norway business on October 15, 2014 for approximately $2.1 billion in proceeds
- Executed agreements in October to add approximately 12,000 net acres to SCOOP position, including prospective acres for the Springer formation

Operations

North America E&P--Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Sales Volumes				
Crude Oil and Condensate (mbbld)				
Bakken	50	34	44	34
Eagle Ford	75	52	68	49
Oklahoma Resource Basins	3	2	2	1
Other North America [(a)]	38	38	37	41
Total Crude Oil and Condensate	166	126	151	125
Natural Gas Liquids (mbbld)				
Bakken	3	2	3	2
Eagle Ford	20	14	18	14
Oklahoma Resource Basins	5	5	5	4
Other North America[(a)]	3	3	2	2
Total Natural Gas Liquids	31	24	28	22
Total Liquid Hydrocarbons (mbbld)				
Bakken	53	36	47	36
Eagle Ford	95	66	86	63
Oklahoma Resource Basins	8	7	7	5
Other North America[(a)]	41	41	39	43
Total Liquid Hydrocarbons	197	150	179	147
Natural Gas (mmcfd)				
Bakken	18	12	17	12
Eagle Ford	130	93	116	92
Oklahoma Resource Basins	63	47	59	49
Other North America[(a)]	106	145	111	165
Total Natural Gas	317	297	303	318
Equivalent Barrels (mboed)				
Bakken	56	38	50	38
Eagle Ford	117	82	105	78
Oklahoma Resource Basins	19	15	17	13
Other North America[(a)]	58	65	58	71
Total North America E&P	250	200	230	200

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

North America E&P segment average net sales volumes in the third quarter and first nine months of 2014 increased 25 percent and 15 percent when compared to the third quarter and first nine months of 2013. Net liquid hydrocarbon sales volumes increased 47 thousand barrels per day ("mbbld") and 32 mbbld for the third quarter and first nine months of 2014, and net natural gas sales volumes increased 20 million cubic feet per day ("mmcfd") and decreased 15 mmcfd for the third quarter and first nine months of 2014, primarily reflecting continued growth from the combined U.S. resource plays, partially offset by the shut-in and exit from Powder River Basin operations. The negative impact of extreme winter weather on availability and completion operations in the first quarter of 2014 is reflected in the smaller increase in net liquid hydrocarbon sales volumes for the nine-month period. Reduced net natural gas sales volumes for the nine-month period were primarily related to the Powder River Basin and to the January 2013 sale of our Alaska assets, 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 117 mboed and 105 mboed in the third quarter and first nine months of 2014 compared to 82 mboed and 78 mboed in the same 2013 periods, for increases of 43 percent and

35 percent. Approximately 64 percent of third quarter sales was crude oil and condensate, 18 percent was natural gas liquids ("NGLs") and 18 percent was natural gas.

Enhanced completion design in the Eagle Ford continues to deliver strong results as the growing population of these wells achieving 180-day cumulative production continues to average 25 percent improvement in volumes as compared to the previous completion design. During the third quarter of 2014, we reached total depth on 93 gross operated wells and brought 87 gross operated wells to sales, compared to 70 reaching total depth and 71 brought to sales in the third quarter of 2013. During the first nine months of 2014, we reached total depth on 264 gross operated wells and brought 221 gross operated wells to sales, compared to 228 reaching total depth and 219 brought to sales in the same 2013 period. Our third quarter of 2014 average spud-to-total depth time was 13 days compared to 12 days in the same 2013 period. Our high-density pad drilling continues to average four wells per pad in 2014. This higher pad density and the longer laterals being drilled in 2014 contribute to the slightly higher spud-to-total depth time in 2014.

Included with the Eagle Ford well counts noted above, we brought online eight Austin Chalk wells, all drilled within the previously delineated acreage. Sixteen additional Austin Chalk wells are currently being drilled, completed or awaiting first production and we expect to complete a total of 30 wells in the Austin Chalk for 2014.

Bakken – Average net sales volumes from the Bakken shale were 56 mboed and 50 mboed in the third quarter and first nine months of 2014 compared to 38 mboed in the same 2013 periods, for increases of 47 percent and 32 percent. Our Bakken production averages approximately 89 percent crude oil, six percent NGLs and five percent natural gas. During the third quarter of 2014, we reached total depth on 25 gross operated wells and brought 19 gross operated wells to sales, compared to 21 reaching total depth and 21 brought to sales in the third quarter of 2013. During the first nine months of 2014, we reached total depth on 60 gross operated wells and brought 49 gross operated wells to sales compared to 61 reaching total depth and 56 brought to sales in the same 2013 period. Our third quarter average time to drill a well was 16 days spud-to-total depth, compared to 18 days in the same 2013 period. We recompleted 16 wells in the Hector and Ajax areas during the third quarter of 2014, with 13 of these wells brought to sales.

Three of four high-density spacing pilots have begun drilling, with each pad comprised of six Middle Bakken and six Three Forks first bench wells. We continue to execute an enhanced completion design pilot program, including elevated proppant volumes, hybrid slickwater fracs, increased stages and cemented liners. Of the 19 Bakken wells brought to sales in the quarter, eight are piloting enhanced completions. In late September an incremental drilling rig was added in the Bakken to provide additional capacity for high-density spacing and enhanced completion pilots.

Oklahoma resource basins – Net sales volumes from the Oklahoma resource basins averaged 19 mboed and 17 mboed in the third quarter and first nine months of 2014 compared to 15 mboed and 13 mboed in the comparable 2013 periods, for increases of 27 percent and 31 percent. Approximately 42 percent of third quarter 2014 sales was liquid hydrocarbons and 58 percent natural gas. During the third quarter of 2014, we reached total depth on four gross operated wells and brought six gross operated wells to sales. Of the wells brought to sales, four were in the SCOOP and two in the Southern Mississippi Trend. We plan to add two incremental rigs in the Oklahoma Resource Basins by year end. During the first nine months of 2014, we reached total depth on 15 gross operated wells and brought ten gross operated wells to sales, compared to eight reaching total depth and nine brought to sales in the same 2013 period.

Wyoming – Operated production at the Powder River Basin field ceased in March 2014. Plug and abandonment activities are expected to be substantially complete in the fourth quarter of 2014.

North America E&P--Exploration

Gulf of Mexico –The operated Key Largo exploration prospect, located on Walker Ridge Block 578, spud in September 2014 as the first well of a multi-year Gulf of Mexico exploration program with a new-build deepwater drillship. We are operator and hold a 60 percent working interest in the prospect.

An exploration well was spud on the Perseus prospect, located on Desoto Canyon Block 231 in September 2014. We hold a 30 percent non-operated 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.

North America E&P--Acquisitions

In an asset acquisition that closed August 2014, we added acreage to our Oklahoma resource position at a cost of approximately $80 million before final settlement adjustments.

International E&P--Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Sales Volumes				
Total Liquid Hydrocarbons (mbbld)				
Equatorial Guinea	27	32	31	32
United Kingdom	6	20	11	18
Libya	6	16	2	32
Total Liquid Hydrocarbons	39	68	44	82
Natural Gas (mmcfd)				
Equatorial Guinea	420	463	434	437
United Kingdom[(a)]	19	26	26	34
Libya	—	30	1	27
Total Natural Gas	439	519	461	498
Equivalent Barrels (mboed)				
Equatorial Guinea	97	109	104	104
United Kingdom[(a)]	9	24	15	24
Libya	6	21	2	37
Total International E&P (mboed)	112	154	121	165
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	6,265	7,302	6,488	6,638
Methanol (mtd)	1,103	1,364	1,078	1,249

(a) Includes natural gas acquired for injection and subsequent resale of 3 mmcfd and 4 mmcfd for the third quarters of 2014 and 2013, and 5 mmcfd and 8 mmcfd for the first nine months of 2014 and 2013.

International E&P segment average net sales volumes in the third quarter and first nine months of 2014 decreased 27 percent and 27 percent when compared to the third quarter and first nine months of 2013. We had lower oil sales from Libya in 2014 as a result of third party labor strikes at the Es Sider terminal. Excluding Libya, net sales volumes decreased 20 percent in the third quarter of 2014 and decreased 7 percent in the first nine months of 2014 compared to the same 2013 periods. The third quarter of 2014 net sales volume decrease, excluding Libya, is primarily as a result of the timing of liquid hydrocarbon liftings from the U.K., lower reliability at the non-operated methanol facility in Equatorial Guinea and planned maintenance activities at the non-operated Forties Pipeline System that lowered operational availability across the Brae complex in the U.K. The net sales volume decrease for the first nine 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, in addition to the third quarter impacts discussed above.

Equatorial Guinea – Average net sales volumes were 97 mboed and 104 mboed in the third quarter and first nine months of 2014 compared to 109 mboed and 104 mboed in the same 2013 periods. Third quarter of 2014 net sales volumes were lower primarily as a result of temporary production curtailments due to unplanned maintenance on the main condensate line as well as lower reliability at the non-operated methanol facility.

An outbreak of the Ebola virus has existed in certain regions of West Africa (Guinea, Liberia, Sierra Leone) for several months. Although neither Equatorial Guinea nor any other African country in which we have business activities has been impacted by Ebola to date, our business operations may be adversely affected through travel or other restrictions. We continue to monitor the situation and are working closely with appropriate external parties to maintain business continuity and the health and well-being of our staff.

United Kingdom – Average net sales volumes were 9 mboed and 15 mboed in the third quarter and first nine months of 2014 compared to 24 mboed in the same 2013 periods, for decreases of 63 percent and 38 percent, primarily due to the timing of liquid hydrocarbon liftings, planned maintenance activities on the non-operated Forties Pipeline System in the third quarter of 2014, reliability issues at the non-operated Foinaven field and natural decline within the Brae fields. Overall, operating availability was lower for all U.K. assets in 2014 due to planned and unplanned maintenance activities. We brought two South Brae infill wells online in the third quarter of 2014. A third South Brae well and a new West Brae well are planned to come online in the first quarter of 2015.

Libya – In July 2014, Libya's National Oil Corporation rescinded force majeure associated with third-party labor strikes at the Es Sider terminal. Our first 2014 lifting occurred in August, and was sourced from existing inventory at the terminal. Production from the Waha concessions resumed in August 2014; however, considerable uncertainty remains around future production and sales levels.

International E&P--Exploration

Kurdistan Region of Iraq – We resumed testing of the Jisik-1 exploration well on the operated Harir Block following suspension of certain operations due to security concerns in the region and continue to closely monitor the situation. In the fourth quarter of 2014, we will commence a 2D seismic program and expect to spud the Mirawa-2 appraisal well. We hold a 45 percent operated working interest in the Harir Block.

On the non-operated Sarsang Block, testing continues on the East Swara Tika-1 exploratory well which reached a total depth of approximately 13,000 feet in June 2014. The co-venturers declared the Swara Tika discovery commercial in May 2014 and filed a field development plan in June. Discussions are ongoing with the Ministry of Natural Resources to finalize the Swara Tika field development plan. 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.

Construction of the phase one production facility on the non-operated Atrush Block continues with first oil expected in 2015. The Chiya Khere-5 development well (formerly Atrush-5) reached total depth in late June 2014. The well will be tested prior to final completion and tie-in to the phase one production facility. The Atrush-4 development well reached total depth in January 2014, completed testing in April 2014 and has been suspended as a future producer. We hold a 15 percent non-operated working interest in the Atrush Block.

Equatorial Guinea – An exploration well on the Sodalita West prospect is expected to spud by the end of 2014 as the first of two offshore exploration wells targeting oil-prone plays.

Kenya – The Sala-2 appraisal well spud in the third quarter of 2014, did not encounter commercial hydrocarbons, and the well costs were charged to dry well expense in the quarter. 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. 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 are in the process of acquiring 2D seismic and plan to drill an appraisal well in 2015. We hold a 50 percent non-operated working interest in the block with the option to operate if a discovery is made.

Gabon – In August 2014, we signed an exploration and production sharing contract for Gabon offshore Block G13, which was subsequently re-named Tchicuate. Located in the deepwater, pre-salt play, the block encompasses 275,000 acres; and, acquisition of 3D seismic is planned to commence in early November 2014. We hold a 100 percent participating interest and operatorship in the block. In the event of development, the Republic of Gabon will assume a 20 percent financed interest in the contract upon commencement of production. The State holds additional rights to participate in the block in the future as a co-investor.

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

International E&P--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. The transaction closed on October 15, 2014 for approximately $2.1 billion in proceeds.

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 58 mboed and 66 mboed in the third quarter and first nine months of 2014 compared to 68 mboed and 81 mboed in the same 2013 periods. The decrease for the quarter was primarily related to a 12-day planned turnaround at Alvheim versus a planned 7-day turnaround in same quarter of 2013, as well as natural field decline. Alvheim was also impacted in the first quarter of 2014 by severe winter weather which resulted in eight days of curtailed production.

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 6 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 Athabasca Oil Sands Project. Our net synthetic crude oil sales volumes were 55 mbbld and 49 mbbld in the third quarter and first nine months of 2014 compared to 49 mbbld and 47 mbbld in the same periods of 2013. The increase for the third quarter of 2014 was the result of improved operational availability at the upgrader and mines and higher beginning bitumen inventories. Comparison of sales volumes for the nine-month periods reflects 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 third quarter and first nine months of 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Average Price Realizations [(a)]				
Crude Oil and Condensate (per bbl)				
Bakken	$85.28	$97.76	$89.07	$92.58
Eagle Ford	93.51	104.08	96.12	102.41
Oklahoma Resource Basins	93.78	101.82	96.23	94.80
Other North America [(b)]	87.50	99.93	90.06	92.75
Total Crude Oil and Condensate	89.65	101.05	92.59	96.54
Natural Gas Liquids (per bbl)				
Bakken	$40.60	$44.08	$46.92	$40.24
Eagle Ford	30.90	30.11	32.64	28.84
Oklahoma Resource Basins	33.64	35.11	36.74	34.91
Other North America [(b)]	51.49	55.81	55.77	54.39
Total Natural Gas Liquids	33.93	35.01	36.96	34.06
Total Liquid Hydrocarbons (per bbl) [(c)]				
Bakken	$82.67	$95.24	$86.66	$89.96
Eagle Ford	79.99	87.96	82.99	86.61
Oklahoma Resource Basins	56.57	51.34	55.58	50.49
Other North America [(b)]	85.28	97.12	87.71	90.30
Total Liquid Hydrocarbons	80.89	90.49	83.89	87.09
Natural Gas (per mcf)				
Bakken	$4.29	$3.73	$5.49	$3.93
Eagle Ford	4.21	3.53	4.59	3.71
Oklahoma Resource Basins	3.97	3.10	4.64	3.79
Other North America [(b)]	4.34	3.62	5.03	3.96
Total Natural Gas	4.21	3.51	4.81	3.86
Benchmarks				
West Texas Intermediate ("WTI") crude oil (per bbl)	$97.25	$105.81	$99.62	$98.20
Louisiana Light Sweet ("LLS") crude oil (per bbl)[(d)]	101.03	110.00	103.63	109.48
Mont Belvieu NGLs (per bbl) [(e)]	32.69	33.46	35.15	33.05
Henry Hub natural gas[(f)] (per mmbtu)[(g)]	4.06	3.58	4.55	3.65

(a) Excludes gains or losses on derivative instruments.

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

(c) Inclusion of realized losses on crude oil derivative instruments would have decreased average liquid hydrocarbon price realizations by $1.81 and $0.30 per bbl for the third quarter and first nine months of 2013. There were no crude oil derivative instruments for the third quarter and first nine months of 2014.

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

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

(f) Settlement date average.

(g) Million British thermal units.

Crude oil and condensate – Our crude oil and condensate price realizations may differ from the benchmark due to the quality and location of the product. Crude oil benchmark prices decreased for third quarter and first nine months of 2014 compared to the same 2013 periods due to a decline in crude oil prices because of increased supply, weak global demand and other geopolitical factors. This price decline continued after quarter end with WTI averaging $84.34 per bbl in October 2014.

Natural gas liquids – The majority of our NGL volumes are sold at reference to Mont Belvieu prices. Average Mount Belvieu NGL prices for the third quarter of 2014 were modestly lower than for the same 2013 period. This was primarily due to softer ethane prices, due to a higher incidence of downtime in the demand driven petroleum chemical industry, and lower crude oil prices. Our net NGL sales volumes continue to grow due to development of our U.S. resource plays with increases of 29 percent and 27 percent during the third quarter and first nine months of 2014 compared to the same 2013 periods.

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 higher in the third quarter of 2014 compared to the same 2013 period primarily because of incremental demand generated from significantly lower storage levels.

International E&P

The following table presents our average price realizations and the related benchmark for crude oil for the third quarter and first nine months of 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Average Price Realizations				
Total Liquid Hydrocarbons (per bbl)				
Equatorial Guinea	$51.83	$57.35	$58.37	$59.54
United Kingdom	88.68	108.34	106.00	108.13
Libya	114.36	124.19	114.86	122.91
Total Liquid Hydrocarbons	66.80	88.47	72.88	94.41
Natural Gas (per mcf)				
Equatorial Guinea[a]	$0.24	$0.24	$0.24	$0.24
United Kingdom	7.60	10.67	8.72	10.78
Libya	—	5.92	5.45	5.26
Total Natural Gas	0.56	1.10	0.73	1.24
Benchmark				
Brent (Europe) crude oil (per bbl)	$101.82	$110.27	$106.56	$108.45

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

Liquid hydrocarbons – Our U.K. liquid hydrocarbon production 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. During the third quarter of 2014, crude oil prices declined driven by weaker demand and increased supply, along with continued global economy and geopolitical factors. This price decline continued after quarter end with Brent averaging $88.05 per bbl in October 2014.

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 fixed-price, term contracts, making realized prices in this area less volatile; therefore, our reported average natural gas realized prices for the International E&P segment will not fully track market price movements.

Oil Sands Mining

The Oil Sands Mining segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational reliability or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix have historically tracked movements in WTI and one-third have historically tracked movements in the Canadian heavy crude oil marker, primarily Western Canadian Select ("WCS"). Comparing the corresponding 2014 and 2013 periods, the WCS discount to WTI widened in the third quarter by $2.80 per barrel; however, in the first nine months of 2014, the WCS discount to WTI narrowed by $1.81 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 third quarter and first nine months of 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Average Price Realizations				
Synthetic Crude Oil (per bbl)	$88.22	$102.64	$90.11	$90.65
Benchmark				
WTI crude oil (per bbl)	$97.25	$105.81	$99.62	$98.20
WCS crude oil (per bbl)[(a)]	$76.99	$88.35	$78.50	$75.27
AECO natural gas sales index (per mmbtu)[(b)]	$3.51	$2.35	$4.32	$2.99

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

Results of Operations

Consolidated Results of Operation

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
Sales and other operating revenues, including related party				
North America E&P	$1,586	$1,321	$4,518	$3,820
International E&P	273	611	1,000	2,332
Oil Sands Mining	457	463	1,217	1,204
Segment sales and other operating revenues, including related party	$2,316	$2,395	$6,735	$7,356
Unrealized loss on crude oil derivative instruments	—	(61)	—	(61)
Sales and other operating revenues, including related party	$2,316	$2,334	$6,735	$7,295

North America E&P sales and other operating revenues increased 20 percent and 18 percent in the third quarter and first nine months of 2014 from the comparable 2013 periods primarily due to the higher net sales volumes from continued growth across our three U.S. resource plays, partially offset by lower crude oil price realizations.

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 September 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended September 30, 2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$1,251	$(174)	$387	$1,464
Natural gas	96	20	7	123
Realized loss on crude oil derivative instruments	(24)	24		—
Other sales	(2)			(1)
Total	$1,321			$1,586

(In millions)	Nine Months Ended September 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Nine Months Ended September 30, 2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$3,490	$(156)	$778	$4,112
Natural gas	335	78	(15)	398
Realized loss on crude oil derivative instruments	(12)	12		—
Other sales	7			8
Total	$3,820			$4,518

International E&P sales and other operating revenues decreased 55 percent and 57 percent in the third quarter and first nine months of 2014 from the comparable 2013 periods. The decreases were primarily due to the lower liquid hydrocarbon net sales volumes 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 average price realizations.

(In millions)	Three Months Ended September 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended September 30, 2014
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$548	$(78)	$(230)	$240
Natural gas	52	(22)	(8)	22
Other sales	11			11
Total	$611			$273

(In millions)	Nine Months Ended September 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Nine Months Ended September 30, 2014
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$2,127	$(258)	$(996)	$873
Natural gas	168	(64)	(12)	92
Other sales	37			35
Total	$2,332			$1,000

Oil Sands Mining sales and other operating revenues changed slightly in the third quarter and first nine months of 2014, from the comparable 2013 periods as shown below.

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 September 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Three Months Ended September 30, 2014
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$461	$(73)	$57	$445
Other sales	2			12
Total	$463			$457

(In millions)	Nine Months Ended September 30, 2013	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Nine Months Ended September 30, 2014
Oil Sands Mining Price-Volume Analysis				

Synthetic crude oil	$1,175	$(7	) $27	$1,195
Other sales	29			22
Total	$1,204			$1,217

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 both the third quarter and first nine months of 2013, the net unrealized loss on crude oil derivative instruments was $61 million. There were no crude oil derivative instruments in the third quarter and first nine months of 2014.

Marketing revenues decreased $112 million and increased $118 million in the third quarter and first nine months of 2014 from the comparable prior-year periods. The decrease in the third quarter of 2014 is related primarily to lower marketing activity levels and crude oil prices in the North America E&P segment. The increase in the first nine months of 2014 is primarily due to higher marketing activity levels in both the North America E&P and OSM segments. Marketing activities include the purchase of commodities from third parties for resale and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Since the volume of marketing activity is based on market dynamics, it can fluctuate from period to period.

Income from equity method investments decreased $25 million and increased $37 million in the third quarter and first nine months of 2014 from the comparable 2013 periods. The decrease in the third quarter of 2014 is primarily due to reliability issues in Equatorial Guinea at the non-operated methanol facility and lower average price realizations. The increase in the first nine months of 2014 is primarily due to higher earnings from our LNG operations in Equatorial Guinea as a result of higher average price realizations and a turnaround in the second quarter of 2013.

Net loss on disposal of assets in the first nine months of 2014 includes the loss on the sale of non-core acreage located in the far northwest portion of the Williston Basin. See Note 6 to the consolidated financial statements for further details on dispositions.

Production expenses increased $53 million in the third quarter of 2014 from the third quarter of 2013. North America E&P segment production expenses increased $28 million primarily related to higher net sales volumes in the U.S. resource plays. OSM segment production expenses increased $25 million primarily as a result of higher net sales volumes.

In the first nine months of 2014, production expenses increased $72 million compared to the same 2013 period. North America E&P segment production expenses increased $77 million primarily related to higher net sales volumes in the U.S. resource plays. International E&P segment production expenses increased $38 million and included $11 million for non-recurring riser repairs in Equatorial Guinea during the first quarter of 2014 and $5 million related to a turnaround at Brae in the U.K. during the second quarter of 2014. Lower sales volumes across the International E&P segment contributed to the higher production expense rate (production expense per barrel of oil equivalent, or "boe"). OSM segment production expenses decreased $43 million in the first nine months of 2014 due to the 2013 turnaround and lower contract services and contract labor costs in 2014.

The following table provides production expense rates for each segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	2014	2013	2014	2013
Production Expense Rate				
North America E&P	$10.16	$11.18	$10.52	$10.72
International E&P	$10.48	$7.64	$9.34	$5.96
Oil Sands Mining [(a)]	$37.38	$40.47	$44.73	$47.30

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

Marketing costs decreased $109 million and increased $120 million in the third quarter and first nine months of 2014 from the comparable 2013 periods, consistent with the marketing revenues changes discussed above.

Exploration expenses were $351 million lower in the first nine months of 2014 than in the comparable 2013 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:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
Exploration Expenses				
Unproved property impairments	$39	$35	$140	$458
Dry well costs	25	24	80	95
Geological and geophysical	10	8	27	44
Other	22	16	67	68
Total exploration expenses	$96	$83	$314	$665

Depreciation, depletion and amortization ("DD&A") increased $80 million and $146 million in the third quarter and first nine months of 2014 from the comparable 2013 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 third quarter and first nine 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, as previously discussed.

The International E&P segment DD&A rate was lower in the third quarter and first nine months of 2014 because a majority of our net sales volumes in the 2014 periods were from countries with lower DD&A rates.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	2014	2013	2014	2013
DD&A Rate				
North America E&P	$26.54	$26.64	$26.65	$26.73
International E&P	$5.30	$8.18	$6.09	$6.28
Oil Sands Mining	$12.75	$12.43	$12.14	$12.27

Impairments are discussed in Note 13 to the consolidated financial statements.

Taxes other than income include production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to sales volumes and revenue. With the increase in North America E&P revenues and net sales volumes, taxes other than income increased $26 million and $55 million in the third quarter and first nine months of 2014 from the comparable 2013 periods. The following table summarizes the components of taxes other than income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
Production and severance	$69	$50	$191	$151
Ad valorem	20	16	58	52
Other	26	23	70	61
Total	$115	$89	$319	$264

General and administrative expenses increased $17 million in the third quarter of 2014 compared to the same 2013 period, primarily due to higher pension settlement expense as well as higher unallocated technical and operations support costs. The increase of $21 million in the first nine months of 2014 compared to the same 2013 period is primarily due to higher pension settlement expense and higher unallocated technical and operations support costs partially offset by lower employee related costs and less contract services.

Net interest and other in the third quarter and first nine months of 2014 was a lower net expense by $16 million and $31 million compared to the same 2013 periods, primarily due to decreases in net foreign currency losses. In addition, a dividend was received in the first quarter of 2014 from a mutual insurance company of which we are an owner.

Provision for income taxes decreased $210 million and $872 million in the third quarter and first nine months of 2014 from the comparable 2013 periods, primarily as a result of reduced pretax income in Libya. See Note 9 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 6 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 September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
North America E&P	$292	$242	$836	$404
International E&P	106	192	487	635
Oil Sands Mining	93	106	212	164
Segment income	491	540	1,535	1,203
Items not allocated to segments, net of income taxes	(187)	(144)	(473)	(408)
Income from continuing operations	304	396	1,062	795
Discontinued operations [a]	127	173	1,058	583
Net income	$431	$569	$2,120	$1,378

(a) We sold our Angola assets in the first quarter of 2014 and closed the sale of our Norway business on October 15, 2014. The Angola and Norway businesses are reflected as discontinued operations in all periods presented.

North America E&P segment income increased $50 million and $432 million after-tax in the third quarter and first nine months of 2014 compared to the same 2013 periods. The increases in both periods are primarily due to higher net sales volumes from the U.S. resource plays, partially offset by lower crude oil price realizations and expenses associated with the higher net sales volumes, such as production expenses and DD&A. Also impacting the comparison of the nine-month period was the previously discussed non-cash unproved property impairments in the first quarter of 2013.

International E&P segment income decreased $86 million and $148 million after-tax in the third quarter and first nine months of 2014 compared to the same 2013 periods. The decreases in both periods are primarily a result of lower net sales volumes in the U.K and Equatorial Guinea and lower commodity price realizations, partially offset by reduced taxes and expenses associated with the lower sales volumes. Lower sales volumes from Libya impacted the decrease when comparing the nine-month periods. 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 decreased $13 million and increased $48 million after-tax in the third quarter and first nine months of 2014 from the comparable 2013 periods. The third quarter 2014 decrease was primarily a result of lower price realizations partially offset by higher sales volumes. The increase in the first nine months of 2014 was primarily the result of lower production expenses and slightly higher net sales volumes.

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 nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,	
(In millions)	2014	2013
Sources of cash and cash equivalents		
Continuing operations	$3,476	$3,300
Discontinued operations	856	741
Disposals of assets	2,237	402
Other	196	149
Total sources of cash and cash equivalents	$6,765	$4,592
Uses of cash and cash equivalents		
Additions to property, plant and equipment	$(3,639)	$(3,383)
Investing activities of discontinued operations	(356)	(435)
Purchases of common stock	(1,000)	(500)
Commercial paper, net	(135)	—
Debt repayments	(34)	(148)
Dividends paid	(401)	(376)
Other	(48)	(80)
Cash held for sale	(655)	—
Total uses of cash and cash equivalents	$(6,268)	$(4,922)

The increase in cash flows from discontinued operations during the first nine months of 2014 is mostly due to changes in working capital driven by substantially lower tax payments during the year as well as the timing of cash receipts from liftings. The third quarter 2014 tax payments were favorably impacted by tax synergies available to our Norway business as a result of the pending sale.

Disposals of assets in the first nine months of 2014 primarily reflect the net proceeds from the sales of our interests in Angola Blocks 31 and 32. In the first nine 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 shows capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,	
(In millions)	2014	2013
North America E&P	$3,246	$2,706
International E&P	386	314
Oil Sands Mining	172	209
Corporate	29	47
Total capital expenditures	3,833	3,276
Change in capital expenditure accrual	(194)	107
Additions to property, plant and equipment	$3,639	$3,383

Purchases of common stock are discussed in Note 18 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 and extended the maturity to May 2019. See Note 16 to the consolidated financial statements for additional terms and rates. At September 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 September 30, 2014, we had $6,423 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.

Asset Disposal

On October 15, 2014, we closed the sale of our Norway business for proceeds of approximately $2.1 billion. The first priority for the use of proceeds is organic reinvestment in our deep and growing U.S. unconventional portfolio. See Note 6 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 22 percent at September 30, 2014, compared to 25 percent at December 31, 2013.

(In millions)	September 30, 2014	December 31, 2013
Commercial paper	$—	$135
Long-term debt due within one year	68	68
Long-term debt	6,355	6,394
Total debt	$6,423	$6,597
Cash and cash equivalents	$761	$264
Equity	$20,226	$19,344
Calculation:		
Total debt	$6,423	$6,597
Minus cash and cash equivalents	761	264
Total debt minus cash and cash equivalents	$5,662	$6,333
Total debt	$6,423	$6,597
Plus equity	20,226	19,344
Minus cash and cash equivalents	761	264
Total debt plus equity minus cash and cash equivalents	$25,888	$25,677
Cash-adjusted debt-to-capital ratio	22 %	25 %

Capital Requirements

On October 29, 2014, our Board of Directors approved a dividend of 21 cents per share for the third quarter of 2014 payable December 10, 2014 to stockholders of record at the close of business on November 19, 2014.

As of September 30, 2014, we plan to make contributions of up to $24 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 September 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 September 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 September 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 (the "Exchange Act"). 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, timing and expectations, maintenance activities and the timing and impact thereof, well spud timing and expectations, operational outlook, future financial position, liquidity and capital resources, the planned use of proceeds from the sale of our Norway business, 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," "may," "should," "would" or similar words indicating that futur are uncertain. While we believe that our assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including 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 SEC.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we assume no duty to revise or update any forward-looking statements 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 13 and 14 to the consolidated financial statements.

The following table provides sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of September 30, 2014.

(In millions)	Fair Value		Incremental Change in Fair Value
Financial assets (liabilities): [a]			
Interest rate swap agreements	$5	[b]	$5
Long-term debt, including amounts due within one year	$(7,057)	[b][c]	$(214)

[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 September 30, 2014 would be $35 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 Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 September 30, 2014.

During the third quarter of 2014, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2014	2013	2014	2013
Segment Income				
North America E&P	$292	$242	$836	$404
International E&P	106	192	487	635
Oil Sands Mining	93	106	212	164
Segment income	491	540	1,535	1,203
Items not allocated to segments, net of income taxes	(187)	(144)	(473)	(408)
Income from continuing operations	304	396	1,062	795
Discontinued operations [(a)]	127	173	1,058	583
Net income	$431	$569	$2,120	$1,378
Capital Expenditures [(b)]				
North America E&P	$1,277	$832	$3,246	$2,706
International E&P	166	120	386	314
Oil Sands Mining	49	66	172	209
Corporate	16	7	29	47
Discontinued operations [(a)]	125	137	376	413
Total	$1,633	$1,162	$4,209	$3,689
Exploration Expenses				
North America E&P	$55	$48	$194	$559
International E&P	41	35	120	106
Total	$96	$83	$314	$665

(a) We sold our Angola assets in the first quarter of 2014 and our Norway business on October 15, 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 September 30,		Nine Months Ended September 30,	
Net Sales Volumes	2014	2013	2014	2013
North America E&P				
Crude Oil and Condensate (mbbld)				
Bakken	50	34	44	34
Eagle Ford	75	52	68	49
Oklahoma Resource Basins	3	2	2	1
Other North America [(c)]	38	38	37	41
Total Crude Oil and Condensate	166	126	151	125
Natural Gas Liquids (mbbld)				
Bakken	3	2	3	2
Eagle Ford	20	14	18	14
Oklahoma Resource Basins	5	5	5	4
Other North America [(c)]	3	3	2	2
Total Natural Gas Liquids	31	24	28	22
Total Liquid Hydrocarbons (mbbld)				
Bakken	53	36	47	36
Eagle Ford	95	66	86	63
Oklahoma Resource Basins	8	7	7	5
Other North America [(c)]	41	41	39	43
Total Liquid Hydrocarbons	197	150	179	147
Natural Gas (mmcfd)				
Bakken	18	12	17	12
Eagle Ford	130	93	116	92
Oklahoma Resource Basins	63	47	59	49
Other North America [(c)]	106	145	111	165
Total Natural Gas	317	297	303	318
Total North America E&P (mboed)	250	200	230	200

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

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
Net Sales Volumes	2014	2013	2014	2013
International E&P				
Total Liquid Hydrocarbons (mbbld)				
Equatorial Guinea	27	32	31	32
United Kingdom	6	20	11	18
Libya	6	16	2	32
Total Liquid Hydrocarbons	39	68	44	82
Natural Gas (mmcfd)				
Equatorial Guinea	420	463	434	437
United Kingdom[d]	19	26	26	34
Libya	—	30	1	27
Total Natural Gas	439	519	461	498
Total International E&P (mboed)	112	154	121	165
Oil Sands Mining				
Synthetic Crude Oil (mbbld)[e]	55	49	49	47
Total Continuing Operations (mboed)	417	403	400	412
Discontinued Operations - Angola (mboed)[a]	—	9	2	9
Discontinued Operations - Norway (mboed)[a]	58	68	66	81
Total Company (mboed)	475	480	468	502
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	6,265	7,302	6,488	6,638
Methanol (mtd)	1,103	1,364	1,078	1,249

(d) Includes natural gas acquired for injection and subsequent resale of 3 mmcfd and 4 mmcfd for the third quarters of 2014 and 2013, and 5 mmcfd and 8 mmcfd for the first nine months of 2014 and 2013.

(e) Includes blendstocks.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
Average Price Realizations	2014	2013	2014	2013
North America E&P				
Crude Oil and Condensate (per bbl)				
Bakken	$85.28	$97.76	$89.07	$92.58
Eagle Ford	93.51	104.08	96.12	102.41
Oklahoma Resource Basins	93.78	101.82	96.23	94.80
Other North America [c]	87.50	99.93	90.06	92.75
Total Crude Oil and Condensate	89.65	101.05	92.59	96.54
Natural Gas Liquids (per bbl)				
Bakken	$40.60	$44.08	$46.92	$40.24
Eagle Ford	30.90	30.11	32.64	28.84
Oklahoma Resource Basins	33.64	35.11	36.74	34.91
Other North America [c]	51.49	55.81	55.77	54.39
Total Natural Gas Liquids	33.93	35.01	36.96	34.06
Total Liquid Hydrocarbons (per bbl) [f]				
Bakken	$82.67	$95.24	$86.66	$89.96
Eagle Ford	79.99	87.96	82.99	86.61
Oklahoma Resource Basins	56.57	51.34	55.58	50.49
Other North America [c]	85.28	97.12	87.71	90.30
Total Liquid Hydrocarbons	80.89	90.49	83.89	87.09
Natural Gas (per mcf)				
Bakken	$4.29	$3.73	$5.49	$3.93
Eagle Ford	4.21	3.53	4.59	3.71
Oklahoma Resource Basins	3.97	3.10	4.64	3.79
Other North America [c]	4.34	3.62	5.03	3.96
Total Natural Gas	4.21	3.51	4.81	3.86

(f) Excludes gains or losses on derivative instruments. Inclusion of realized losses on crude oil derivative instruments would have decreased average liquid hydrocarbon price realizations by $1.81 and $0.30 per bbl for the third quarter and first nine months of 2013. There were no crude oil derivative instruments for the third quarter and first nine months of 2014.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
Average Price Realizations	2014	2013	2014	2013
International E&P				
Total Liquid Hydrocarbons (per bbl)				
Equatorial Guinea	$51.83	$57.35	$58.37	$59.54
United Kingdom	88.68	108.34	106.00	108.13
Libya	114.36	124.19	114.86	122.91
Total Liquid Hydrocarbons	66.80	88.47	72.88	94.41
Natural Gas (per mcf)				
Equatorial Guinea(g)	$0.24	$0.24	$0.24	$0.24
United Kingdom	7.60	10.67	8.72	10.78
Libya	—	5.92	5.45	5.26
Total Natural Gas	0.56	1.10	0.73	1.24
Oil Sands Mining				
Synthetic Crude Oil (per bbl)	$88.22	$102.64	$90.11	$90.65
Discontinued Operations - Angola (per boe)(a)	—	$107.01	$99.82	$104.49
Discontinued Operations - Norway (per boe)(a)	$98.62	$110.97	$105.29	$109.37

(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.

Part II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. There have been no material changes to the risk factors under Item 1A. Risk Factors in our 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 September 30, 2014, of our equity securities that are registered pursuant to Section 12 of the Exchange Act.

	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]
07/01/14 - 07/31/14	8,314	$40.04	—	$1,500,285,529
08/01/14 - 08/31/14	4,910	$39.00	—	$1,500,285,529
09/01/14 - 09/30/14	188,262	$41.02	—	$1,500,285,529
Total	201,486	$40.93	—	

(a) 176,463 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In September 2014, 25,023 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 September 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.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

November 4, 2014		MARATHON OIL CORPORATION
	By:	/s/ John R. Sult
		John R. Sult
		Executive Vice President and Chief Financial Officer
		(Duly Authorized Officer)

Exhibit Index

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	Exhibit	Filing Date	SEC File No.	
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	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement.	8-K	10.1	08/01/14	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
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.