MARATHON OIL CORP
Form 10-Q
November 06, 2013

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, 2013

OR

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

Commission file number 1-5153

Marathon Oil Corporation
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	25-0996816 (I.R.S. Employer Identification No.)

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

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

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

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

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

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

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

There were 696,634,081 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2013.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended September 30, 2013

INDEX

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)	2013	2012	2013	2012
Revenues and other income:				
Sales and other operating revenues, including related party	$3,119	$3,405	$9,978	$9,324
Marketing revenues	668	631	1,597	2,237
Income from equity method investments	114	122	309	260
Net gain (loss) on disposal of assets	(6)	(12)	(4)	126
Other income	19	15	38	38
Total revenues and other income	3,914	4,161	11,918	11,985
Costs and expenses:				
Production	575	601	1,767	1,581
Marketing, including purchases from related parties	664	629	1,588	2,238
Other operating	126	112	323	311
Exploration	153	170	751	477
Depreciation, depletion and amortization	720	625	2,205	1,779
Impairments	11	8	49	271
Taxes other than income	91	55	268	178
General and administrative	152	179	490	499
Total costs and expenses	2,492	2,379	7,441	7,334
Income from operations	1,422	1,782	4,477	4,651
Net interest and other	(66)	(53)	(209)	(160)
Income before income taxes	1,356	1,729	4,268	4,491
Provision for income taxes	787	1,279	2,890	3,231
Net income	$569	$450	$1,378	$1,260
Per Share Data				
Net Income:				
Basic	$0.80	$0.64	$1.95	$1.79
Diluted	$0.80	$0.63	$1.94	$1.78
Dividends paid	$0.19	$0.17	$0.53	$0.51
Weighted average shares:				
Basic	707	706	708	705
Diluted	711	709	712	709

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)	2013	2012	2013	2012
Net income	$569	$450	$1,378	$1,260
Other comprehensive income (loss)				
Postretirement and postemployment plans				
Change in actuarial loss and other	34	(90)	180	(80)
Income tax (provision) benefit on postretirement and postemployment plans	(13)	32	(67)	28
Postretirement and postemployment plans, net of tax	21	(58)	113	(52)
Derivative hedges				
Net unrecognized gain	—	1	—	1
Income tax provision on derivatives	—	—	—	—
Derivative hedges, net of tax	—	1	—	1
Foreign currency translation and other				
Unrealized gain (loss)	1	—	(3)	—
Income tax benefit on foreign currency translation and other	—	—	1	—
Foreign currency translation and other, net of tax	1	—	(2)	—
Other comprehensive income (loss)	22	(57)	111	(51)
Comprehensive income	$591	$393	$1,489	$1,209

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, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$354	$684
Receivables	2,562	2,418
Inventories	360	361
Other current assets	179	299
Total current assets	3,455	3,762
Equity method investments	1,216	1,279
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,171 and $19,266	27,822	28,272
Goodwill	499	525
Other noncurrent assets	2,784	1,468
Total assets	$35,776	$35,306
Liabilities		
Current liabilities:		
Commercial paper	$200	$200
Accounts payable	2,406	2,324
Payroll and benefits payable	162	217
Accrued taxes	1,511	1,983
Other current liabilities	326	173
Long-term debt due within one year	68	184
Total current liabilities	4,673	5,081
Long-term debt	6,433	6,512
Deferred tax liabilities	2,481	2,432
Defined benefit postretirement plan obligations	713	856
Asset retirement obligations	2,027	1,749
Deferred credits and other liabilities	455	393
Total liabilities	16,782	17,023
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 – 74 million and 63 million shares	(2,949)	(2,560)
Additional paid-in capital	6,603	6,616
Retained earnings	14,892	13,890
Accumulated other comprehensive loss	(322)	(433)
Total stockholders' equity	18,994	18,283
Total liabilities and stockholders' equity	$35,776	$35,306

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)	2013	2012
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$1,378	$1,260
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred income taxes	17	(27)
Depreciation, depletion and amortization	2,205	1,779
Impairments	49	271
Pension and other postretirement benefits, net	41	(56)
Exploratory dry well costs and unproved property impairments	619	287
Net loss (gain) on disposal of assets	4	(126)
Equity method investments, net	12	(14)
Changes in:		
Current receivables	(151)	(646)
Inventories	(8)	(6)
Current accounts payable and accrued liabilities	(286)	156
All other operating, net	161	(66)
Net cash provided by operating activities	4,041	2,812
Investing activities:		
Acquisitions, net of cash acquired	(74)	(806)
Additions to property, plant and equipment	(3,818)	(3,509)
Disposal of assets	402	193
Investments - return of capital	45	42
All other investing, net	34	49
Net cash used in investing activities	(3,411)	(4,031)
Financing activities:		
Commercial paper, net	—	1,839
Debt issuance costs	—	(9)
Debt repayments	(148)	(111)
Purchases of common stock	(500)	—
Dividends paid	(376)	(360)
All other financing, net	70	26
Net cash (used in) provided by financing activities	(954)	1,385
Effect of exchange rate changes on cash	(6)	12
Net increase (decrease) in cash and cash equivalents	(330)	178
Cash and cash equivalents at beginning of period	684	493
Cash and cash equivalents at end of period	$354	$671

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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

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

Beginning in the first quarter of 2013, we changed the presentation of our consolidated statements of income, primarily to present additional details of revenues and expenses and to classify certain expenses more consistently with our peer group of independent exploration and production companies. To effect these changes, reclassifications of previously reported amounts were made and are reflected in these consolidated financial statements. As a result of the reclassifications, general and administrative expenses for the third quarter and first nine months of 2012 increased by $40 million and $110 million which primarily includes certain costs associated with operations support and operations management. Offsetting reductions are reflected in production, other operating and exploration expenses and taxes other than income.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation 2012 Annual Report on Form 10-K. The results of operations for the third quarter and first nine months of 2013 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Not Yet Adopted

In June 2013, the Financial Accounting Standards Board ("FASB") ratified the Emerging Issues Task Force consensus on Issue 13-C, which requires that an unrecognized tax benefit or a portion of an unrecognized tax benefit 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 is effective for us beginning in the first quarter of 2014 and should be applied prospectively to unrecognized tax benefits that exist as of the effective date. Early adoption and retrospective application are permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within United States generally accepted accounting principles ("U.S. GAAP"). An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of accumulated other comprehensive income. This standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This accounting standards update was effective for us beginning the first quarter of 2013 and we present the required disclosures in Note 16. 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 December 2011, an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity's financial position. Entities are required to disclose both gross information and net information about in-scope financial instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. The accounting standards update was effective for us beginning the first quarter of 2013 and we include the required disclosures in Note 14. 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 ("AOSP"), in which we hold a 20 percent undivided interest, contracted with a wholly-owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with current liabilities of $3 million recorded at September 30, 2013, consistent with December 31, 2012. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. 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 $707 million as of September 30, 2013. 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. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

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 and stock appreciation rights, provided the effect is not antidilutive.

	Three Months Ended September 30,			
	2013		2012	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Net income	$569	$569	$450	$450
Weighted average common shares outstanding	707	707	706	706
Effect of dilutive securities	—	4	—	3
Weighted average common shares, including dilutive effect	707	711	706	709
Per share:				
Net income	$0.80	$0.80	$0.64	$0.63

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30,			
	2013		2012	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Net income	$1,378	$1,378	$1,260	$1,260
Weighted average common shares outstanding	708	708	705	705
Effect of dilutive securities	—	4	—	4
Weighted average common shares, including dilutive effect	708	712	705	709
Per share:				
Net income	$1.95	$1.94	$1.79	$1.78

The per share calculations above exclude 4 million and 5 million stock options for the third quarter and first nine months of 2013, as they were antidilutive. Excluded for the third quarter and first nine months of 2012 were 10 million stock options.

5. Dispositions

2013 - North America Exploration and Production ("E&P") Segment

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

In January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments made in the second quarter of 2013, the gain on this sale was $55 million.

2013 - International E&P Segment

In June 2013, we entered into an agreement to sell our non-operated 10 percent working interest in the Production Sharing Contract and Joint Operating Agreement in Block 31 offshore Angola. This transaction, valued at $1.5 billion before closing adjustments, is expected to close in the fourth quarter of 2013, subject to government and regulatory approvals. Angola Block 31 is reflected as held for sale in the September 30, 2013 consolidated balance sheet as follows:

(In millions)	
Other current assets	$15
Other noncurrent assets	1,598
Total assets	1,613
Other current liabilities	42
Deferred credits and other liabilities	41
Total liabilities	$83

2012 - North America E&P Segment

In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale for proceeds of $9 million. A net loss of $18 million was recorded.

In January 2012, we closed on the sale of our interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This included our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests including the Eugene Island pipeline system. A gain of $166 million was recorded in the first quarter of 2012.

8

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

2012 - International E&P Segment
In May 2012, we reached an agreement to relinquish our operatorship of and interests in the Bone Bay and Kumawa exploration licenses in Indonesia. A $36 million payment to settle all of our obligations related to these licenses, including well commitments, was accrued and reported as a loss on disposal of assets in the second quarter of 2012 and we paid the accrued amount in the third quarter of 2012.

6. Acquisitions
During the third quarters and first nine months of 2013 and 2012, our business combinations related to properties acquired by our North America E&P segment in the Eagle Ford shale in south Texas. The pro forma impact of these transactions, individually and in the aggregate, is not material to our consolidated statements of income for any periods presented.
The fair values of assets acquired and liabilities assumed in each of these business combinations were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. 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 and assumptions regarding future operating and development costs. The discount rates used in the discounted cash flow analyses were approximately 10 percent for the both the 2013 and 2012 transactions.

2013
In July 2013, we acquired 4,800 net undeveloped acres in the core of the Eagle Ford shale in a transaction valued at $97 million, including carried interest of $23 million. The transaction was accounted for as a business combination, with the entire up-front cash consideration of $74 million allocated to property, plant and equipment at the acquisition date.

2012
We acquired approximately 20,000 net acres in the core of the Eagle Ford shale during the first nine months of 2012. The largest transaction was the acquisition of Paloma Partners II, LLC, which closed during the third quarter for cash consideration of $768 million. This transaction was accounted for as a business combination. Smaller transactions closed during the second quarter of 2012.
The following table summarizes the amounts allocated to the assets acquired and liabilities assumed for Paloma Partners II, LLC based upon their fair values at the acquisition date:

(In millions)	
Assets:	
Cash	$8
Receivables	22
Inventories	1
Total current assets acquired	31
Property, plant and equipment	822
Total assets acquired	$853
Liabilities:	
Accounts payable	78
Asset retirement obligations	7
Total liabilities assumed	85
Net assets acquired	$768

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

7. Segment Information

Beginning in 2013, we changed our reportable segments and revised our management reporting to better reflect the growing importance of United States unconventional resource plays to our business. All prior-year periods presented have been recast to reflect these new segments.

We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- 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 as discussed below, 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, net of associated income tax effects. Unrealized gains or losses on crude oil derivative instruments, impairments, gains or losses on dispositions or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

Differences between segment totals and our consolidated totals for income taxes and depreciation, depletion and amortization represent amounts related to corporate administrative activities and other unallocated items which are included in “Items not allocated to segments, net of income taxes” in the reconciliation below. Total capital expenditures include accruals but not corporate activities.

	Three Months Ended September 30, 2013			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$1,321	$1,396	$463	$3,180
Marketing revenues	607	58	3	668
Segment revenues	$1,928	$1,454	$466	3,848
Unrealized loss on crude oil derivative instruments				(61)
Total revenues				$3,787
Segment income	$242	$321	$106	$669
Income from equity method investments	—	114	—	114
Depreciation, depletion and amortization	490	179	54	723
Income tax provision	143	714	35	892
Capital expenditures	831	254	65	1,150

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended September 30, 2012			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$993	$1,907	$460	$3,360
Marketing revenues	548	73	10	631
Segment revenues	$1,541	$1,980	$470	3,991
Unrealized gain on crude oil derivative instruments				45
Total revenues				$4,036
Segment income	$107	$405	$66	$578
Income from equity method investments	1	121	—	122
Depreciation, depletion and amortization	360	194	60	614
Income tax provision	66	1,219	20	1,305
Capital expenditures	1,045	229	41	1,315
	Nine Months Ended September 30, 2013			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$3,820	$5,015	$1,204	$10,039
Marketing revenues	1,391	194	12	1,597
Segment revenues	$5,211	$5,209	$1,216	11,636
Unrealized loss on crude oil derivative instruments				(61)
Total revenues				$11,575
Segment income	$404	$1,156	$164	$1,724
Income from equity method investments	—	309	—	309
Depreciation, depletion and amortization	1,458	575	154	2,187
Income tax provision	242	2,860	55	3,157
Capital expenditures	2,705	720	207	3,632
	Nine Months Ended September 30, 2012			
(In millions)	N.A. E&P	Int'l E&P	OSM	Total
Revenues:				
Sales and other operating revenues	$2,738	$5,383	$1,158	$9,279
Marketing revenues	2,019	193	25	2,237
Segment revenues	$4,757	$5,576	$1,183	11,516
Unrealized gain on crude oil derivative instruments				45
Total revenues				$11,561
Segment income	$281	$1,185	$154	$1,620
Income from equity method investments	2	258	—	260
Depreciation, depletion and amortization	964	622	159	1,745
Income tax provision	166	3,260	50	3,476
Capital expenditures	2,887	569	136	3,592

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

The following reconciles total revenues to sales and other operating revenues as reported in the consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Total revenues	$3,787	$4,036	$11,575	$11,561
Less: Marketing revenues	668	631	1,597	2,237
Sales and other operating revenues, including related party	$3,119	$3,405	$9,978	$9,324

The following reconciles segment income to net income as reported in the consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Segment income	$669	$578	$1,724	$1,620
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(61)	(146)	(288)	(294)
Unrealized gain (loss) on crude oil derivative instruments	(39)	29	(39)	29
Net gain (loss) on dispositions	—	(11)	(9)	72
Impairments	—	—	(10)	(167)
Net income	$569	$450	$1,378	$1,260

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)	2013	2012	2013	2012
Service cost	$14	$12	$1	$1
Interest cost	16	16	3	4
Expected return on plan assets	(17)	(14)	—	—
Amortization:				
– prior service cost (credit)	2	2	(2)	(2)
– actuarial loss	9	12	—	—
Net settlement loss[a]	15	34	—	—
Net periodic benefit cost	$39	$62	$2	$3

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

	Nine months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2013	2012	2013	2012
Service cost	$42	$37	$3	$3
Interest cost	47	48	9	11
Expected return on plan assets	(50)	(46)	—	—
Amortization:				
– prior service cost (credit)	5	6	(5)	(5)
– actuarial loss	38	37	—	—
Net settlement loss[a]	32	34	—	—
Net periodic benefit cost	$114	$116	$7	$9

(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. Such settlements were recorded for our U.S. plans in the second and third quarters of 2013 and the third quarter of 2012.

During the second and third quarters of 2013 and the third quarter of 2012, 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 decreases of $24 million and $163 million in actuarial losses in other comprehensive income for the three months and nine months ended September 30, 2013, and an increase of $103 million in actuarial losses, net of settlement loss, for the three months and nine months ended September 30, 2012.

During the first nine months of 2013, we made contributions of $50 million to our funded pension plans. We expect to make additional contributions up to an estimated $17 million to our funded pension plans over the remainder of 2013. Current benefit payments related to unfunded pension and other postretirement benefit plans were $19 million and $12 million during the first nine months of 2013.

9. Income Taxes

The effective income tax rate is influenced by a variety of factors including the geographic sources of income and the relative magnitude of these sources of income. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in “Corporate and other unallocated items” in Note 7.

Our effective income tax rates in the first nine months of 2013 and 2012 were 68 percent and 72 percent. These rates are higher than the U.S. statutory rate of 35 percent due to earnings from foreign jurisdictions, primarily Norway and Libya, where the tax rates are in excess of the U.S. statutory rate. In Libya, where the statutory tax rate is in excess of 90 percent, sales decreased in the third quarter of 2013 due to labor strikes at the Es Sider oil terminal and there remains uncertainty around future production and sales levels. Reliable estimates of 2013 and 2012 annual ordinary income from our Libyan operations could not be made and the range of possible scenarios when including ordinary income from our Libyan operations in the worldwide annual effective tax rate calculation demonstrates significant variability. As such, for the first nine months of 2013 and 2012, estimated annual effective tax rates were calculated excluding Libya and applied to consolidated ordinary income excluding Libya and the tax provision applicable to Libyan ordinary income was recorded as a discrete item in the periods. Excluding Libya, the effective tax rates would be 60 percent and 64 percent for the first nine months of 2013 and 2012. In the third quarter of 2013, we recorded a net favorable tax adjustment of $42 million, largely related to greater expected utilization of foreign tax credits in future periods than previously estimated.

10. Inventories

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

	September 30,	December 31,

(In millions)	2013	2012
Liquid hydrocarbons, natural gas and bitumen	$46	$73
Supplies and other items	314	288
Inventories, at cost	$360	$361

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

11. Property, Plant and Equipment

(In millions)	September 30, 2013	December 31, 2012
North America E&P	$25,858	$23,748
International E&P	12,342	13,214
Oil Sands Mining	10,337	10,127
Corporate	456	449
Total property, plant and equipment	48,993	47,538
Less accumulated depreciation, depletion and amortization	(21,171)	(19,266)
Net property, plant and equipment	$27,822	$28,272

During the third quarter of 2013, our Libya production operations were impacted due to labor strikes at the Es Sider oil terminal. We had three oil liftings from Libya in July 2013, but no oil liftings in August or September. Uncertainty around sustained production and sales levels from Libya have existed since the first quarter of 2011 when production operations were suspended until limited production resumed in the fourth quarter of the same year. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. As of September 30, 2013, our net property, plant and equipment investment in Libya was approximately $743 million.

Exploratory well costs capitalized greater than one year after completion of drilling were $220 million as of September 30, 2013. The net decrease of $9 million from December 31, 2012 primarily related to the conveyance of our interests in the Marcellus natural gas shale play to the operator in February 2013.

Included in the total costs suspended for greater than one year are $127 million related to Angola Block 31 and $22 million related to Equatorial Guinea. The Angola Block 31 costs are included in the other noncurrent assets held for sale reported in Note 5. We intend to develop Block D offshore Equatorial Guinea through a unitization with the Alba field, which is now expected be completed late in 2014.

12. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations during the first nine months of 2013:

(In millions)	2013
Beginning balance[a]	$1,783
Incurred, including acquisitions	10
Settled, including dispositions	(41)
Accretion expense (included in depreciation, depletion and amortization)	103
Revisions to previous estimates	306
Held for sale	(41)
Ending balance[a]	$2,120

[a] Beginning and ending balances include asset retirement obligations of $34 million and $93 million classified as short-term at December 31, 2012 and September 30, 2013.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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, 2013 and December 31, 2012 by fair value hierarchy level.

	September 30, 2013				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$—	$5	$—	$—	$5
Interest rate	—	11	—	—	11
Foreign currency	—	1	—	—	1
Derivative instruments, assets	$—	$17	$—	$—	$17
Derivative instruments, liabilities					
Commodity	$—	$14	$—	$—	$14
Foreign currency	—	14	—	—	14
Derivative instruments, liabilities	$—	$28	$—	$—	$28

	December 31, 2012				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$—	$52	$—	$1	$53
Interest rate	—	21	—	—	21
Foreign currency	—	18	—	—	18
Derivative instruments, assets	$—	$91	$—	$1	$92

Commodity swaps in Level 2 are measured at fair value with a market approach using prices obtained from exchanges or pricing services, which have been corroborated with data from active markets for similar assets or liabilities. Commodity options in Level 2 are valued using the Black-Scholes Model. Inputs to this model include prices as noted above, discount factors, and implied market volatility. The inputs to this fair value measurement are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Collateral deposits related to commodity derivatives are in broker accounts covered by master netting agreements.

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

Fair Values - Nonrecurring

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

	Three Months Ended September 30,			
	2013		2012	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$5	$11	$2	$8

	Nine Months Ended September 30,			
	2013		2012	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$5	$49	$77	$271

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

All long-lived assets held for use that were impaired in the first nine months of 2013 and 2012 were held by our North America E&P segment. The fair values of each discussed below were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

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.

In early 2012, production rates from the Ozona development in the Gulf of Mexico declined significantly. Accordingly, our reserve engineers prepared evaluations of our future production as well as our reserves and an impairment of $261 million was recorded in the first quarter of 2012. As the development produced towards abandonment pressures, further downward revisions of reserves were taken, resulting in an additional impairment recorded in the fourth quarter of 2012. Ozona production ceased in the first quarter of 2013 and an additional $21 million impairment 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 and 2012 were a result of reduced drilling expectations, reductions of estimated reserves or declining natural gas prices.

Fair Values – Financial Instruments

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

The following table summarizes financial instruments, excluding receivables, commercial paper, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at September 30, 2013 and December 31, 2012.

	September 30, 2013		December 31, 2012	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$168	$165	$189	$186
Total financial assets	168	165	189	186
Financial liabilities				
Other current liabilities	13	13	13	13
Long-term debt, including current portion[(a)]	6,941	6,461	7,610	6,642
Deferred credits and other liabilities	164	161	94	94
Total financial liabilities	$7,118	$6,635	$7,717	$6,749

(a) Excludes capital leases.

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

Most of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions, is used to measure the fair value of such debt. Because these quotes cannot be independently verified to an active market they are considered Level 3 inputs. 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

14. Derivatives
For information regarding the fair value measurement of derivative instruments, see Note 13. All of our interest rate and commodity derivatives are subject to enforceable master netting arrangements or similar agreements under which we may report net amounts. Netting is assessed by counterparty, and as of September 30, 2013 and December 31, 2012, 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, 2013 and December 31, 2012.

	September 30, 2013			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$1	$—	$1	Other current assets
Interest rate	11	—	11	Other noncurrent assets
Total Designated Hedges	12	—	12	
Not Designated as Hedges				
Commodity	5	—	5	Other current assets
Total Not Designated as Hedges	5	—	5	
Total	$17	$—	$17	

	September 30, 2013			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$—	$14	$14	Other current liabilities
Total Designated Hedges	—	14	14	
Not Designated as Hedges				
Commodity	—	14	14	Other current liabilities
Total Not Designated as Hedges	—	14	14	
Total	$—	$28	$28	

	December 31, 2012			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$18	$—	$18	Other current assets
Interest rate	21	—	21	Other noncurrent assets
Total Designated Hedges	39	—	39	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$91	$—	$91	

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

Derivatives Designated as Fair Value Hedges

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

Maturity Dates	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate
October 1, 2017	$600	4.67 %
March 15, 2018	$300	4.51 %

As of December 31, 2012, we had multiple interest rate swap agreements with a total notional amount of $600 million, a weighted average, LIBOR-based, floating rate of 4.70 percent and a maturity date of October 1, 2017.

As of September 30, 2013 and December 31, 2012, our foreign currency forwards had an aggregate notional amount of 3,115 million and 3,043 million Norwegian Kroner at a weighted average forward rate of 5.874 and 5.780. These forwards hedge our current Norwegian tax liability and have settlement dates through February 2014.

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

		Gain (Loss)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2013	2012	2013	2012
Derivative					
Interest rate	Net interest and other	$5	$6	$(9)	$17
Foreign currency	Provision for income taxes	$5	$22	$(41)	$(18)
Hedged Item					
Long-term debt	Net interest and other	$(5)	$(6)	$9	$(17)
Accrued taxes	Provision for income taxes	$(5)	$(22)	$41	$18

Derivatives not Designated as Hedges

In August 2012, we entered into crude oil derivatives related to a portion of our forecast North America E&P crude oil sales through December 31, 2013. These commodity derivatives were not designated as hedges and are shown in the table below.

Remaining Term	Bbls per Day	Weighted Average Price per Bbl	Benchmark
Swaps			
October 2013 - December 2013	20,000	$96.29	West Texas Intermediate
October 2013 - December 2013	25,000	$109.19	Brent
Option Collars			
October 2013 - December 2013	15,000	$90.00 floor / $101.17 ceiling	West Texas Intermediate
October 2013 - December 2013	15,000	$100.00 floor / $116.30 ceiling	Brent

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statements of income.

		Gain (Loss)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2013	2012	2013	2012
Commodity	Sales and other operating revenues, including related party	$(86)	$45	$(73)	$46

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

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 2013:

	Stock Options			Restricted Stock		
	Number of Shares		Weighted Average Exercise Price	Awards		Weighted Average Grant Date Fair Value
Outstanding at December 31, 2012	19,536,965		$26.19	4,177,884		$29.02
Granted	1,704,734	[a]	$33.30	1,254,935		$32.96
Options Exercised/Stock Vested	(2,098,887	)	$22.31	(1,609,730	)	$28.09
Canceled	(708,701	)	$34.01	(384,719	)	$29.91
Outstanding at September 30, 2013	18,434,111		$26.99	3,438,370		$30.80

[a] The weighted average grant date fair value of stock option awards granted was $10.51 per share.

Performance unit awards

In the first quarter of 2013, we granted 353,600 performance units to certain officers that provide a cash payout upon the achievement of certain performance goals at the end of a 36-month performance period. The performance goals are tied to our total shareholder return (“TSR”) as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. At the grant date, each unit represents the value of one share of our common stock, while payout after completion of the performance period will be based on the value of anywhere from zero to two times the number of units granted. Dividend equivalents accrue during the performance period and are paid in cash at the end of the performance period based on the number of shares that would represent the value of the units. The fair value of these performance units is re-measured on a quarterly basis using the Monte Carlo simulation method. These performance units are accounted for as liability awards because they are to be settled in cash at the end of the performance period and their fair value is expensed over the performance period.

16. Reclassifications Out of Accumulated Other Comprehensive Loss

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

(In millions)	Three Months Ended September 30, 2013		Nine Months Ended September 30, 2013		Income Statement Line
Accumulated Other Comprehensive Loss Components	Income (Expense)				
Postretirement and postemployment plans					
Amortization of actuarial loss	$(9	)	$(38	)	General and administrative
Net settlement loss	(15	)	(32	)	General and administrative
	9		26		Provision for income taxes
	(15	)	(44	)	Net of tax
Other insignificant items, net of tax	—		(1	)	
Total reclassifications for the period	$(15	)	$(45	)	Net income

17. Stockholders' Equity

In the third quarter of 2013, we acquired 14 million common shares at a cost of $500 million under our $5 billion authorized share repurchase program.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

18. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
(In millions)	2013	2012
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$216	$164
Income taxes paid to taxing authorities	3,218	3,457
Commercial paper, net:		
Commercial paper - issuances	$4,975	$10,420
- repayments	(4,975)	(8,581)
Noncash investing activities:		
Asset retirement costs capitalized	$316	$47
Debt payments made by United States Steel	—	19
Liabilities assumed in acquisition	—	85
Change in capital expenditure accrual	(129)	170
Asset retirement obligations assumed by buyer	92	7

19. Commitments and Contingencies

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

Litigation – In March 2011, Noble Drilling (U.S.) LLC ("Noble") filed a lawsuit against us in the District Court of Harris County, Texas, alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. In April 2013, we filed a counterclaim against Noble alleging, among other things, breach of contract and breach of the duty of good faith relating to the multi-year drilling contract. The counterclaim also included a breach of contract claim for reimbursement for the value of fuel used by Noble under an offshore daywork drilling contract. The parties have reached a tentative settlement of this litigation. We believe that the settlement of this litigation will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Contractual commitments – At September 30, 2013, Marathon's contract commitments to acquire property, plant and equipment were $1,154 million.

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

Beginning in 2013, we changed our reportable segments and revised our management reporting to better reflect the growing importance of United States unconventional resource plays to our business. All prior-year periods presented have been recast to reflect these new segments.

We are an international energy company with operations in the United States, Canada, Africa, the Middle East and Europe. We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- North America Exploration and Production ("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.

Certain sections of this Quarterly Report on Form 10-Q, including Management's Discussion and Analysis of Financial Condition and Results of Operations contain forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as "anticipates," "believes," "estimates," "expects," "targets," "plans," "projects," "could," "may," "should," "would" or similar words indicating that future outcomes a uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2012 Annual Report on Form 10-K. We assume no duty to update these statements as to any future date.

Key Operating and Financial Activities

In the third quarter of 2013, notable items were:

- North America E&P net liquid hydrocarbon sales volumes increased 35 percent over the same quarter of last year
- Eagle Ford shale averaged net liquid hydrocarbon sales of 66 thousand barrels per day ("mbbld"), a 100 percent increase
- Bakken shale averaged net liquid hydrocarbon sales of 36 mbbld, a 24 percent increase
- Acquisition of 4,800 net acres in the core of the Eagle Ford shale in a transaction valued at $97 million including a carried interest
- Labor strikes at Es Sider oil terminal in Libya since late July with no oil liftings in August or September
- Norway turnaround completed in nine days, on time and on budget
- Madagascar operated exploration well began drilling in deepwater Gulf of Mexico on De Soto Canyon Block 757
- Agreement in principle reached to sell our working interest in Angola Block 32 with an anticipated transaction value of $590 million, excluding purchase price adjustments
- First deepwater Gabon pre-salt discovery with the non-operated Diaman-1B exploration well
- Dividend increased by 12 percent to 19 cents per share
- 14 million common shares repurchased for $500 million at an average price of $35.53 per share

Some significant fourth quarter activities to November 6, 2013 include:

- Announced receipt of approval from the Kurdistan Regional Government for the first phase in the oil development of the Atrush Block in the Kurdistan Region of Iraq
- Announced Mirawa-1 oil and natural gas discovery on our operated Harir block in the Kurdistan Region of Iraq
- High bidder as operator on two deepwater blocks in the pre-salt play offshore Gabon: G13 and E12, which is subject to government approvals and negotiation of the exploration and production sharing contracts

Overview and Outlook
North America E&P
Production
Net liquid hydrocarbon and natural gas sales volumes averaged 200 thousand barrels of oil equivalent per day ("mboed") in both the third quarter and first nine months of 2013 compared to 172 mboed and 155 mboed in the third quarter and first nine months of 2012, for increases of approximately 16 percent and 29 percent, respectively. Net liquid hydrocarbon sales volumes increased for both the third quarter and first nine months of 2013, primarily reflecting the impact of our ongoing development programs in the Eagle Ford and Bakken shale resource plays, while net natural gas sales volumes decreased 19 percent and 7 percent during the same periods, primarily due to the sale of our Alaska assets in January 2013. Excluding the sales volumes related to Alaska in both nine-month periods, our average net natural gas sales volumes increased 21 percent primarily due to the previously mentioned development programs.
Eagle Ford – In 2013, production growth continued in the Eagle Ford shale play. Average net sales volumes were 81 mboed and 78 mboed in the third quarter and first nine months of 2013 compared to 40 mboed and 25 mboed in the same periods of 2012. Approximately 63 percent of the first nine months of 2013 production was crude oil and condensate, 17 percent was natural gas liquids ("NGLs") and 20 percent was natural gas. In the third quarter of 2013, the amount of crude oil and condensate transported by pipeline was approximately 70 percent. The ability to transport more barrels by pipeline enables us to reduce costs, improve reliability and lessen our environmental footprint.
During the third quarter of 2013, we reached total depth on 70 gross operated wells and brought 71 gross operated wells to sales, with 228 gross operated wells reaching total depth and 219 gross operated wells brought on line in the first nine months of 2013. With approximately 97 percent pad drilling in the third quarter of 2013, which continues to improve efficiencies and reduce costs, our third quarter average spud-to-total depth time was 12 days, compared to 15 days spud-to-total depth in the same period of 2012.
To support production growth across the Eagle Ford operating area, approximately 192 miles of gathering lines were installed in the first nine months of 2013, for a total of over 670 miles. We now have 24 central gathering and treating facilities, with one more to be completed in 2013.
We continue to evaluate the potential of downspacing to 40-acre and 60-acre units, with the results of the downspacing pilots expected to be released in December 2013. We also continue to evaluate the Austin Chalk and Pearsall formations across our acreage position. To date, we have completed four Austin Chalk wells. Early Austin Chalk production results suggest that the mix of crude oil and condensate, NGLs and natural gas is similar to Eagle Ford condensate wells. Also in the second quarter of 2013, one Pearsall well was completed.
Bakken – Average net sales volumes from the Bakken shale were 38 mboed in both the third quarter and first nine months of 2013 compared to 30 mboed and 27 mboed in the same periods of 2012. Our Bakken production averages approximately 90 percent crude oil, 4 percent NGLs and 6 percent natural gas. During the third quarter of 2013, we reached total depth on 21 gross operated wells and brought the same number to sales. During the first nine months of 2013, we reached total depth on 61 gross operated wells and brought 56 gross operated wells to sales. Our third quarter average time to drill a well continued to improve, averaging 14 days spud-to-total depth, compared to 18 days spud-to-total depth in the same period of 2012.
Oklahoma Resource Basins – Net sales volumes from the Anadarko Woodford shale averaged 15 mboed in the third quarter and 13 mboed in the first nine months of 2013 compared to 10 mboed and 7 mboed in the same periods of 2012. During the third quarter of 2013, we reached total depth on three gross operated wells and two gross operated wells were brought to sales, while during the first nine months of 2013 we reached total depth on eight gross operated wells and brought nine gross operated wells to sales. We spud two wells in the Mississippi Lime formation in central Oklahoma during October 2013 and expect to spud wells in the Granite Wash around year end.
Exploration
Gulf of Mexico – In September 2013, we began drilling our operated exploration well on the Madagascar prospect located on De Soto Canyon Block 757. We have reduced our working interest in the Madagascar prospect from 100 percent to 40 percent as a result of two farm-outs. We expect the well to reach total depth late in the fourth quarter of 2013.

We participated in an appraisal well on the Gunflint prospect located on Mississippi Canyon Block 992 in which we hold an 18 percent non-operated working interest. The appraisal well successfully encountered 109 feet of net pay within the primary reservoir targets. After penetrating the initial appraisal targets, the well was deepened to a previously untested Lower Miocene interval. Commercial hydrocarbons were not encountered in the deeper exploration objective. Additional exploration potential remains in an adjacent structure to the north, which is a candidate for future exploration following development of the confirmed resources.

The first appraisal well on the Shenandoah prospect located on Walker Ridge Block 51, in which we have a 10 percent non-operated working interest, reached total depth in the first quarter of 2013. This appraisal well successfully encountered more than 1,000 net feet of oil pay in multiple high-quality Lower Tertiary-aged reservoirs. Additional appraisal drilling is anticipated to begin in 2014.

In the second quarter of 2013, at a total cost of $33 million, we were awarded 100 percent working interest leases in two Gulf of Mexico blocks: Keathley Canyon Block 340 on the Colonial prospect and Keathley Canyon Block 153, an extension to the Meteor prospect on our existing Keathley Canyon Block 196 lease. Keathley Canyon Blocks 340 and 153 are both inboard-Paleogene prospects.

Canada – During the first quarter of 2012, we submitted a regulatory application relating to our Canada in-situ assets at Birchwood, for a proposed 12 mbbld steam assisted gravity drainage ("SAGD") demonstration project. We are expecting to receive regulatory approval for this project in mid-2014. Upon receiving this approval, we will further evaluate our development plans.

International E&P

Production

Net liquid hydrocarbon and natural gas sales volumes averaged 231 mboed and 255 mboed during the third quarter and first nine months of 2013 compared to 280 mboed and 259 mboed in the same periods of 2012, which is 18 percent lower for the quarter and an slight decrease for the nine-month period. We had three oil liftings in Libya during July 2013 but no oil liftings in August or September due to labor strikes at the Es Sider oil terminal, for average net liquid hydrocarbon sales volumes of 16 mbbld in the third quarter of 2013 compared to 49 mbbld in the same quarter of 2012. Both the third quarter and first nine months of 2013 include net liquid hydrocarbon sales volumes of 9 mbbld from the PSVM development located on the northeastern portion of Angola Block 31 which had first sales in February 2013.

Equatorial Guinea – Average net sales volumes were 109 mboed and 105 mboed in the third quarter and first nine months of 2013 compared to 116 mboed and 106 mboed in the same periods of 2012. Third quarter 2012 sales volumes were higher than normal due to the timing of liquid hydrocarbon liftings. The planned turnaround that occurred in April 2013 was safely completed in 22 days, eight days ahead of schedule and below budget. Sales in the second quarter of 2013 were impacted by the turnaround, but recovered in the third quarter.

Norway – Average net sales volumes from Norway were 68 mboed and 81 mboed in the third quarter and first nine months of 2013 compared to 89 mboed and 91 mboed in the same periods of 2012. A planned nine-day turnaround in Norway resulted in lower production and sales volumes during the third quarter of 2013, with rates returning to normal levels within the latter half of the quarter. Production declines, while present, continue to be less than expected as a result of strong operational performance (with unplanned downtime at less than 2 percent for the first nine months of 2013), production optimization efforts, recent infill well performance at the upper end of expectations, as well as a delay in anticipated water breakthrough at the Volund field.

United Kingdom – Average net sales volumes were 24 mboed in the third quarter and first nine months of 2013 compared to 22 mboed and 23 mboed in the same periods of 2012. Production at the non-operated Foinaven field was shut-in in mid-July 2013 due to compression and subsea equipment issues and resumed at partial rates in late August. Maintenance activities as well as planned pipeline curtailments also impacted production at the operated, North Sea Brae fields during the third quarter of 2013. Sales volumes for prior-year periods were also impacted by both planned and unplanned maintenance activities as well as the timing of liquid hydrocarbon liftings.

Exploration

Kurdistan Region of Iraq – We hold a 45 percent operated working interest in the Harir block. In October 2013, we announced the Mirawa-1 discovery on the Harir block. The Mirawa-1 was drilled to a total depth of 14,000 feet and encountered multiple stacked oil and natural gas producing zones with equipment constrained test flow rates of more than 11 mbbld of oil, 72 million cubic feet per day ("mmcfd") of non-associated natural gas and 1,700 barrels per day of condensate. We have suspended the well for potential future use as a producing well, and moved the drilling rig to the Jisik-1 prospect located nine miles to the northwest to test a similar structure on the Harir Block.

Following evaluation of the Safen-1 dry well in October, we notified the Kurdistan Ministry of Natural Resources that we do not intend to participate in any further exploration on the Safen Block.

Following the successful appraisal program on the non-operated Atrush Block and a declaration of commerciality, a plan for field development was approved by the Kurdistan Ministry of Natural Resources in late September 2013. The development project will consist of drilling three production wells and constructing a central processing facility. We expect first production by early 2015 with estimated initial gross production of approximately 30 mbbld of oil. The approval of the field development plan for Phase 1 provides for a 25-year production period. Subject to further drilling and testing results, and partner and government approvals, a potential Phase 2 development could add an additional 30 gross mbbld facility. Within the potential Phase 2 development area, the Atrush-3 appraisal well, located approximately four miles east of existing wells, confirmed the extension of the oil bearing reservoir and has been suspended as a potential future producer. We hold a 15 percent working interest in the Atrush Block.

On the non-operated Sarsang block, of the two exploration wells which began drilling in the second half of 2012, tests have been completed on the Gara well. All zones were water-wet and the well was plugged and abandoned in August 2013. On the Mangesh well, five drill stem tests have been completed and further testing is planned. The East Swara Tika exploration well, which began in July 2013, has been drilled to a depth of 5,300 feet toward a planned total depth of 11,000 feet. This well will test additional resource potential to the northeast of the previously announced Swara Tika discovery. We hold a 25 percent working interest in the Sarsang Block.

Ethiopia – Drilling on the Tultule prospect, approximately two miles from the Sabisa-1 well on the onshore South Omo block in a frontier rift basin, commenced in September 2013 with a projected total depth of 7,900 feet. The well is expected to reach total depth by the end of the fourth quarter of 2013. The Sabisa-1 exploration well encountered reservoir quality sands, oil and heavy gas shows and a thick shale section. The presence of oil prone source rocks, reservoir sands and good seals is encouraging for the numerous fault bounded traps identified in the basin. Because of mechanical issues, the well was abandoned before a full evaluation could be completed. We hold a 20 percent non-operated working interest in the South Omo block.

Gabon – The Diaman-1B well in the Diaba License G4-223 offshore Gabon reached total depth in the third quarter of 2013, encountering 160-180 net feet of hydrocarbon pay in the deepwater pre-salt play. Preliminary analysis suggests that the hydrocarbons are natural gas with condensate content, pending results of ongoing analyses of well data. We hold a 21 percent non-operated working interest in the Diaba License.

In late October 2013, we were the high bidder as operator on two deepwater blocks in the pre-salt play. Award of the blocks, G13 and E12, is subject to government approvals and negotiation of the exploration and production sharing contracts.

Norway – The non-operated Sverdrup exploration well on PL 330 offshore Norway that commenced drilling in June 2013 was deemed to be dry. The Darwin (formerly Veslemoy) exploration well was drilled in the first quarter of 2013 on PL 531 in which we hold a 10 percent non-operated fully-carried working interest. Gas shows were recorded in the Paleocene objective section, although no hydrocarbons were found in the Cretaceous section and the well has been plugged and abandoned.

Poland – After an extensive evaluation of our exploration activities in Poland and unsuccessful attempts to find commercial levels of hydrocarbons, we have elected to conclude operations in the country. We are in the process of relinquishing the concessions.

Kenya – The first exploratory well on Block 9, the Bahasi-1, began drilling in September 2013 and is expected to reach a total depth of 9,800 feet in the fourth quarter of 2013. We hold a 50 percent non-operated working interest in Block 9.

Angola – The Kaombo development, located in the southeastern portion of Block 32, is expected to be sanctioned late in 2013 or early in 2014. First production from the Kaombo development is expected in 2017. See discussion of the anticipated disposal of our interest in Block 32 below.

Oil Sands Mining

Our Oil Sands Mining operations consist of a 20 percent non-operated working interest in the Athabasca Oil Sands Project (“AOSP”). Our net synthetic crude oil sales were 49 mbbld and 47 mbbld in the third quarter and first nine months of 2013 compared to 53 mbbld and 47 mbbld in the same periods of 2012. For the first nine months of 2013, the impact of strong reliability experienced at both mines and the upgrader during the first and third quarters of 2013, was offset by unplanned mine downtime and a planned upgrader turnaround during the second quarter of 2013.

Acquisitions and Dispositions

In September 2013, we announced that we had reached an agreement in principle to sell our non-operated 10 percent working interest in the Production Sharing Contract and Joint Operating Agreement in Angola Block 32. The anticipated transaction has a value of approximately $590 million, excluding closing adjustments. Pending execution of definitive agreements and government approval, the transaction is expected to close in the fourth quarter of 2013.

In July 2013, we acquired 4,800 net undeveloped acres in the core of the Eagle Ford shale in a transaction valued at $97 million, including carried interest of $23 million.

In June 2013, we entered into an agreement to sell our non-operated 10 percent working interest in the Production Sharing Contract and Joint Operating Agreement in Angola Block 31. This transaction, valued at $1.5 billion before closing adjustments, is expected to close in the fourth quarter of 2013, subject to government and regulatory approvals.

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 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 made in the second quarter of 2013, the pretax gain on this sale was $55 million.
In January 2013, government approval was received for our acquisition of a 20 percent non-operated interest in the onshore South Omo concession in Ethiopia.
As previously disclosed, we had engaged in discussions with respect to a potential sale of a portion of our 20 percent outside-operated interest in the AOSP. An agreement was not reached with the prospective purchaser and negotiations have been terminated. We are not engaged in further discussions with respect to a potential sale of these assets.
We continue to progress the sale of assets in an ongoing effort to optimize our portfolio for profitable growth, with a previously stated goal of divesting between $1.5 billion and $3 billion over the period of 2011 through 2013. Including the anticipated sale of our interest in Angola Block 32, we have agreed upon or completed divestitures of approximately $3.5 billion, surpassing the $3 billion upper end of our three-year target.
The above discussions include forward-looking statements with respect to expectations to spud wells in the Granite Wash, exploration drilling activity in the Gulf of Mexico, Ethiopia, the Kurdistan Region of Iraq and Kenya, the timing of sanction and first production from the Kaombo development in Angola, the timing of first production for the Atrush Block, a potential Phase 2 development on the Atrush Block and other potential development projects, plans to exit Poland, the award of two blocks in Gabon, the timing of closing the sale of our 10 percent working interest in Block 31 offshore Angola, the anticipated sale of our 10 percent working interest in Block 32 offshore Angola, and the projected asset dispositions through 2013. The average times to drill a well may not be indicative of future drilling times. The current production rates may not be indicative of future production rates. Factors that could potentially affect the wells to be spud in the Granite Wash, exploration drilling activity in the Gulf of Mexico, Ethiopia, the Kurdistan Region of Iraq and Kenya, the timing of sanction and first production from the Kaombo development in Angola, the timing of first production for the Atrush Block, and a potential Phase 2 development on the Atrush Block and other potential development projects include pricing, supply and demand for liquid hydrocarbons and natural gas, the amount of capital available for exploration and development, regulatory constraints, 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 and third-party approvals and permits, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other geological, operating and economic considerations. The award of two blocks in Gabon is subject to government approvals and negotiation of the Exploration and Production Sharing Contracts. The timing of closing the sale of our working interest in Block 31offshore Angola is subject to the satisfaction of customary closing conditions and obtaining necessary government and regulatory approvals. The anticipated sale of our working interest in Angola Block 32 is subject to the execution of definitive agreements and obtaining government approval. The expected timing and rate of production for the Atrush Block, the potential development of Phase 2 of the Atrush Block, plans to exit Poland and the projected asset dispositions through 2013 are based on current expectations, estimates, and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Market Conditions

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Worldwide prices have been volatile in recent years. The following table lists benchmark crude oil and natural gas price averages relative to our North America E&P and International E&P segments in the third quarter and first nine months of 2013 and 2012.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2013	2012	2013	2012
West Texas Intermediate ("WTI") crude oil (Dollars per barrel)	$105.81	$92.20	$98.20	$96.16
Brent (Europe) crude oil (Dollars per barrel)	$110.27	$109.61	$108.45	$112.17
Henry Hub natural gas (Dollars per million British thermal units ("mmbtu"))[(a)]	$3.58	$2.81	$3.65	$2.59

[(a)] Settlement date average.

North America E&P

Liquid hydrocarbons – The quality, location and composition of our liquid hydrocarbon production mix can cause our U.S. liquid hydrocarbon realizations to differ from the WTI benchmark.

Quality – Light sweet crude contains less sulfur and tends to be lighter than sour crude oil so that refining it is less costly and produces higher value products; therefore, light sweet crude is considered of higher quality and typically sells at a price that approximates WTI or at a premium to WTI. The percentage of our North America E&P crude oil and condensate production that is light sweet crude has been increasing as onshore production from the Eagle Ford and Bakken shale plays increases and production from the Gulf of Mexico declines. In the third quarter and first nine months of 2013, the percentage of our U.S. crude oil and condensate production that was sweet averaged 76 percent and 75 percent compared to 65 percent and 58 percent in the same periods of 2012.

Location – In recent years, crude oil sold along the United States Gulf Coast, such as that from the Eagle Ford shale, has been priced based on the Louisiana Light Sweet benchmark which prices at a premium to WTI and moves similarly to Brent, while production from inland areas farther from large refineries has been priced lower. During the third quarter of 2013, the WTI discount from Brent narrowed significantly.

Composition – The proportion of our liquid hydrocarbon sales that are NGLs continues to increase due to our development of United States unconventional liquids-rich plays. NGLs were 16 percent of our North America E&P liquid hydrocarbon sales volumes in the third quarter and 15 percent in the first nine months of 2013 compared to 12 percent and 10 percent in the same periods of 2012.

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 27 percent and 41 percent higher for the third quarter and first nine months of 2013 compared to the same periods of the prior year.

International E&P

Liquid hydrocarbons – Our international crude oil production is relatively sweet and is generally sold in relation to the Brent crude benchmark, which changed little comparing the third quarters of 2013 and 2012, but was 3 percent lower in the first nine months of 2013 than in the same period of 2012.

Natural gas – Our major international natural gas-producing regions are Europe and Equatorial Guinea. Natural gas prices in Europe have been considerably higher than in the U.S. in recent years. In the case of Equatorial Guinea, our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. The natural gas sales from Equatorial Guinea are at fixed prices; therefore, our reported average natural gas realized prices may 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 problems or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil marker, primarily Western Canadian Select ("WCS"). An increase in the WTI benchmark prices, coupled with a smaller WCS discount from WTI in the third quarter of 2013 compared to the same period of 2012, is reflected in our improved average realizations. This narrowing of the discount began in March 2013.

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, respectively.

The table below shows benchmark prices that impacted both our revenues and variable costs for the third quarter and first nine months of 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2013	2012	2013	2012
WTI crude oil (Dollars per barrel)	$105.81	$92.20	$98.20	$96.16
WCS crude oil (Dollars per barrel)[(a)]	$88.35	$70.49	$75.27	$74.21
AECO natural gas sales index (Dollars per mmbtu)[(b)]	$2.35	$2.27	$2.99	$2.03

(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

Consolidated income before income taxes in the third quarter and first nine months of 2013 was approximately 22 percent and 5 percent lower than in the same periods of 2012 primarily related to decreases in international liquid hydrocarbon sales volumes and average realizations. The effective tax rate was 68 percent in the first nine months of 2013 compared to 72 percent in the first nine months of 2012, with the decrease primarily related to lower income from operations in Libya and Norway, which are higher tax jurisdictions. As a result, net income for the third quarter and first nine months of 2013 increased 26 percent and 9 percent.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Sales and other operating revenues, including related party:				
North America E&P	$1,321	$993	$3,820	$2,738
International E&P	1,396	1,907	5,015	5,383
Oil Sands Mining	463	460	1,204	1,158
Segment sales and other operating revenues, including related party	$3,180	$3,360	$10,039	$9,279
Unrealized gain (loss) on crude oil derivative instruments	(61)	45	(61)	45
Total sales and other operating revenues, including related party	$3,119	$3,405	$9,978	$9,324

Total sales and other operating revenues decreased $286 million in the third quarter and increased $654 million in the first nine months of 2013 from the comparable prior-year periods. The $328 million and $1,082 million increases in the North America E&P segment in the third quarter and first nine months of 2013 were primarily due to higher liquid hydrocarbon sales volumes resulting from ongoing development programs in the Eagle Ford and Bakken shale resource plays as well as higher liquid hydrocarbon realizations, partially offset by lower natural gas sales volumes, primarily the result of the sale of our Alaska assets, over the same periods of 2012. Realized losses on our North America E&P crude oil derivative instruments were $25 million and $12 million in the third quarter and first nine months of 2013, while there were no realized gains or losses on crude oil derivative instruments in the same periods of 2012.

The following table gives details of net sales volumes and average realizations of our North America E&P segment.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
North America E&P Operating Statistics				
Net liquid hydrocarbon sales volumes (mbbld) (a)	150	111	147	98
Liquid hydrocarbon average realizations (per bbl) (b) (c)	$90.49	$83.56	$87.09	$87.07
Net crude oil and condensate sales volumes (mbbld)	126	98	125	88
Crude oil and condensate average realizations (per bbl) (b)	$101.05	$89.89	$96.54	$92.00
Net natural gas liquids sales volumes (mbbld)	24	13	22	10
Natural gas liquids average realizations (per bbl) (b)	$35.01	$37.88	$34.06	$41.99
Net natural gas sales volumes (mmcfd)	297	366	318	343
Natural gas average realizations (per mcf)(b)	$3.51	$3.61	$3.86	$3.73

(a) Includes crude oil, condensate and natural gas liquids.

(b) Excludes gains and losses on derivative instruments

(c) Inclusion of realized gains (losses) on crude oil derivative instruments would have decreased average liquid hydrocarbon realizations by $1.81 per bbl and $0.30 per bbl for the third quarter and first nine months of of 2013. There were no realized gains (losses) on crude oil derivative instruments in the third quarter and first nine months of of 2012.

International E&P sales and other operating revenues decreased $511 million and $368 million in the third quarter and first nine months of 2013 from the comparable prior-year periods. The decrease in the third quarter of 2013 was primarily due to lower liquid hydrocarbon sales volumes in Libya and Norway, partially offset by higher liquid hydrocarbon sales volumes in Angola as previously discussed. The decrease in the first nine months of 2013 was primarily due to lower liquid hydrocarbon sales volumes in Norway and Libya and lower liquid hydrocarbon realizations, partially offset by higher liquid hydrocarbon sales volumes in Angola.

The following table gives details of net sales volumes and average realizations of our International E&P segment.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
International E&P Operating Statistics				
Net liquid hydrocarbon sales volumes (mbbld)[(a)]				
Europe	81	94	91	97
Africa	57	88	73	73
Total International E&P	138	182	164	170
Liquid hydrocarbon average realizations (per bbl)				
Europe	$113.73	$112.34	$112.12	$115.73
Africa	$84.58	$98.65	$92.26	$97.00
Total International E&P	$101.68	$105.71	$103.25	$107.69
Net natural gas sales volumes (mmcfd)				
Europe[(b)]	69	100	84	102
Africa	493	485	464	434
Total International E&P	562	585	548	536
Natural gas average realizations (per mcf)				
Europe	$11.61	$10.10	$11.98	$10.05
Africa[(c)]	$0.59	$0.63	$0.53	$0.39
Total International E&P	$1.95	$2.25	$2.29	$2.23

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Includes natural gas acquired for injection and subsequent resale of 4 mmcfd and 18 mmcfd for the third quarters of 2013 and 2012, and 8 mmcfd and 16 mmcfd for the first nine months of 2013 and 2012.

(c) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO, and EGHoldings, equity method investees. We include our share of Alba Plant LLC's, AMPCO's and EGHoldings' income in our International E&P segment.

Oil Sands Mining sales and other operating revenues increased $3 million and $46 million in the third quarter and first nine months of 2013 from the comparable prior-year periods. Synthetic crude oil sales volumes were lower in the third quarter of 2013; however, average realizations were higher versus the comparable 2012 period primarily due to increases in the WTI and WCS benchmark prices. The increase for the first nine months of 2013 resulted from higher synthetic crude oil average realizations primarily as a result of a larger proportion of sales attributable to a premium grade of synthetic crude oil when compared to the same period in 2012.

The following table gives details of net sales volumes and average realizations of our Oil Sands Mining segment.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Oil Sands Mining Operating Statistics				
Net synthetic crude oil sales volumes (mbbld) [(a)]	49	53	47	47
Synthetic crude oil average realizations (per bbl)	$102.64	$81.13	$90.65	$83.58

(a) Includes blendstocks.

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. These crude oil derivative instruments resulted in a $61 million net unrealized loss in the third quarter and first nine months of 2013 compared to a net unrealized gain of $45 million in the same periods of 2012. See Note 14 to the consolidated financial statements and Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional information about our derivative positions.

Marketing revenues increased $37 million in the third quarter of 2013 and decreased $640 million in the first nine months of of 2013 from the comparable prior-year periods. North America E&P segment marketing activities, formerly referred to as supply optimization activities, which include the purchase of commodities from third parties for resale and represented the majority of these variances, decreased in the first nine months of 2013 due to market dynamics. Despite this year-to-date trend, there was a slight increase in the third quarter of 2013 when compared to 2012. These activities serve to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points.

Income from equity method investments decreased $8 million in the third quarter of 2013 versus the third quarter of 2012; however, it increased $49 million in the first nine months of 2013 from the comparable prior-year period, primarily due to higher LNG average realizations.

Net gain (loss) on disposal of assets in the first nine months of 2013 includes a $114 million loss on the sale of our interests in the DJ Basin, a $43 million loss on the conveyance of our interests in the Marcellus natural gas shale play to the operator, a $98 million gain on the sale of our interest in the Neptune gas plant and a $55 million gain on the sale of our remaining assets in Alaska. The net gain on disposal of assets in the first nine months of 2012 consists primarily of the $166 million gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems and a $36 million loss related to our exit from Indonesia. See Note 5 to the consolidated financial statements for information about these dispositions.

Production expenses decreased $26 million in the third quarter of 2013 compared to the same quarter in 2012 primarily due to lower feedstock and contract labor costs in the OSM segment, partially offset by higher production expenses in the North America E&P segment related to increased sales volumes in the Eagle Ford and Bakken shale plays. Production expenses increased $186 million in the first nine months of 2013 from the comparable period of 2012. The North America E&P increase is primarily related to increased sales volumes in Eagle Ford and Bakken, partially offset by lower Alaska production expenses due to the asset sale in the first quarter of 2013. The International E&P increase is primarily related to 2013 first production from Angola Block 31 and a planned Norway third quarter 2013 turnaround. The OSM segment increase is primarily related to a planned turnaround in the second quarter of 2013.

Marketing expenses increased $35 million and decreased $650 million in the third quarter and first nine months of 2013 from the same periods of 2012, consistent with the marketing revenue changes discussed above.

Exploration expenses were $17 million lower in the third quarter of 2013 than in the same quarter in 2012 due to lower unproved property impairments and geological and geophysical costs partially offset by higher dry well costs, including the Sverdrup well in Norway. Exploration costs were $274 million higher in the first nine months of 2013 than in the same period of 2012, primarily due to larger unproved property impairments. The first quarter of 2013 included $340 million in unproved property impairments on Eagle Ford shale leases that either had expired or that we do not expect to drill or extend. The following table summarizes the components of exploration expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Unproved property impairments	$42	$78	$465	$148
Dry well costs	83	35	154	139
Geological and geophysical	9	30	48	104
Other	19	27	84	86
Total exploration expenses	$153	$170	$751	$477

Depreciation, depletion and amortization ("DD&A") increased $95 million and $426 million in the third quarter and first nine months of 2013 from the comparable prior-year periods. Our segments apply the units-of-production method to the majority of their assets; therefore, the previously discussed increases in North America E&P sales volumes generally result in similar changes in DD&A. The DD&A rate (expense per barrel of oil equivalent), which is impacted by changes in reserves and capitalized costs, can also cause changes in our DD&A. An increase in the North America E&P DD&A rate in the third quarter and first nine months of 2013 compared to the same prior-year periods was primarily due to the ongoing development programs in the Eagle Ford and Bakken shale resource plays. A slightly lower International E&P DD&A rate in the first nine months of 2013 compared to the same period in 2012, was primarily due to reserve increases for Norway and partially offset the impact of the higher North America E&P rate and higher sales volumes.

The following table provides DD&A rates for each segment.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	2013	2012	2013	2012
DD&A rate				
North America E&P	$27	$23	$27	$23
International E&P	$8	$8	$8	$9
Oil Sands Mining	$12	$13	$12	$13

Impairments in the first nine months of 2013 primarily related to the Powder River Basin and the Ozona development in the Gulf of Mexico. Impairments in the first nine months of 2012 were also related to the Ozona development in the Gulf of Mexico. See Note 13 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the United States which tend to increase or decrease in relation to sales volumes and revenues.

General and administrative expenses decreased $27 million and $9 million in the third quarter and first nine months of 2013 from the same periods in 2012. The decrease in the third quarter of 2013 is primarily due to a lower pension settlement loss in the third quarter of 2013.

Net interest and other increased $13 million and $49 million in the third quarter and first nine months of 2013 from the comparable periods of 2012 primarily due to lower capitalized interest in 2013.

Provision for income taxes decreased $492 million and $341 million in the third quarter and first nine months of 2013 from the comparable periods of 2012 primarily due to the decrease in pretax income, primarily in Libya.

The effective income tax rate is influenced by a variety of factors including the geographic sources of income and the relative magnitude of these sources of income. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to items not allocated to segments is shown in corporate and other unallocated items in the segment income table below.

Our effective income tax rates in the first nine months of 2013 and 2012 were 68 percent and 72 percent. These rates are higher than the U.S. statutory rate of 35 percent due to earnings from foreign jurisdictions, primarily Norway and Libya, where the tax rates are in excess of the U.S. statutory rate. In Libya, where the statutory tax rate is in excess of 90 percent, sales decreased in the third quarter of 2013 due to labor strikes at the Es Sider oil terminal and there remains uncertainty around future production and sales levels. Reliable estimates of 2013 and 2012 annual ordinary income from our Libyan operations could not be made and the range of possible scenarios when including ordinary income from our Libyan operations in the worldwide annual effective tax rate calculation demonstrates significant variability. As such, for the first nine months of 2013 and 2012, estimated annual effective tax rates were calculated excluding Libya and applied to consolidated ordinary income excluding Libya and the tax provision applicable to Libyan ordinary income was recorded as a discrete item in the periods. Excluding Libya, the effective tax rates would be 60 percent and 64 percent for the first nine months of 2013 and 2012. In the third quarter of 2013, we recorded a net favorable tax adjustment of $42 million, largely related to greater expected utilization of foreign tax credits in future periods than previously estimated.

Segment Income

(In millions)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
North America E&P	$242	$107	$404	$281
International E&P	321	405	1,156	1,185
Oil Sands Mining	106	66	164	154
Segment income	669	578	1,724	1,620
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(61)	(146)	(288)	(294)
Unrealized gain (loss) on crude oil derivative instruments	(39)	29	(39)	29
Net gain (loss) on dispositions	—	(11)	(9)	72
Impairments	—	—	(10)	(167)
Net income	$569	$450	$1,378	$1,260

North America E&P segment income increased $135 million and $123 million in the third quarter and first nine months of 2013 compared to the same periods of 2012. The increases are largely due to increased liquid hydrocarbon sales volumes primarily in the Eagle Ford and Bakken shale resource plays. The third quarter increase also reflects a $92 million decrease in exploration expenses, however, the first nine months of 2013 includes unproved property impairments which partially offset the revenue increase.

International E&P segment income decreased $84 million and $29 million in the third quarter and first nine months of 2013 compared to the same periods of 2012. These decreases are primarily related to the lower liquid hydrocarbon sales volumes and higher production expenses previously discussed, as well as increases of $75 million and $108 million in exploration expenses for the third quarter and first nine months of 2013, partially offset by lower income taxes.

Oil Sands Mining segment income increased $40 million and $10 million in the third quarter and first nine months of 2013 compared to the same periods of 2012. These increases are primarily due to higher synthetic crude oil realizations.

Critical Accounting Estimates

There have been no changes to our critical accounting estimates subsequent to December 31, 2012.

Accounting Standards Not Yet Adopted

In June 2013, the Financial Accounting Standards Board ("FASB") ratified the Emerging Issues Task Force consensus on Issue 13-C, which requires that an unrecognized tax benefit or a portion of an unrecognized tax benefit 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 is effective for us beginning in the first quarter of 2014 and should be applied prospectively to unrecognized tax benefits that exist as of the effective date. Early adoption and retrospective application are permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within United States generally accepted accounting principles ("U.S. GAAP"). An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed.

This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities was $4,041 million in the first nine months of 2013, compared to $2,812 million in the first nine months of 2012, primarily reflecting the impact of increased North America liquid hydrocarbon volumes on operating income.

Net cash used in investing activities totaled $3,411 million in the first nine months of 2013, compared to $4,031 million in the first nine months of 2012. Significant investing activities are additions to property, plant and equipment and disposal of assets. Additions in both periods primarily related to spending on U.S. unconventional resource plays, particularly the Eagle Ford shale. Disposals of assets totaled $402 million and $193 million in the first nine months of 2013 and 2012, with 2013 net proceeds primarily related to the sales of our interests in our Alaska assets, the Neptune gas plant, and the DJ Basin. In 2012, net proceeds resulted primarily from the sale of our interests in several Gulf of Mexico crude oil pipeline systems.

For further information regarding capital expenditures by segment, see Supplemental Statistics.

Net cash used in financing activities was $954 million in the first nine months of 2013, compared to $1,385 million provided by financing activities in the first nine months of 2012. During the first nine months of 2013, we repurchased $500 million of our common stock under our authorized share repurchase program. Repayments of debt were $148 million in the first nine months of 2013 and $111 million in the first nine months of 2012. We also drew a net $1,839 million of commercial paper in the first nine months of 2012. Dividends paid of $376 million and $360 million were a significant use of cash in both nine-month periods.

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, 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

At September 30, 2013, we had no borrowings against our revolving credit facility and $200 million outstanding under our U.S. commercial paper program that is backed by the revolving credit facility. During the first nine months of 2013, $4,975 million of commercial paper was issued and $4,975 million of commercial paper was repaid.

At September 30, 2013, we had $6,501 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.

Anticipated Asset Disposals

The previously discussed sale of our interest in Angola Block 31 and the agreement in principle to sell our interest in Angola Block 32 are both expected to close in the fourth quarter of 2013, subject to the execution of definitive agreements for Block 32 and government and regulatory approvals. Anticipated proceeds from these transactions are $1.5 billion and $590 million, respectively, before closing adjustments. We expect to use a portion of the proceeds to repurchase common shares as discussed below and the remainder to strengthen our balance sheet and for general corporate purposes.

Shelf Registration

We are a "well-known seasoned issuer" for purposes of SEC rules, thereby allowing us to use a universal shelf registration statement should we choose to issue and sell various types of equity and debt securities. Beginning in the first quarter of 2013, we changed our reportable segments and expect to recast all periods presented to reflect these new segments in our consolidated financial statements no later than upon filing our 2013 Annual Report on Form 10-K with the SEC. When appropriate, we will update and file our universal shelf registration statement.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 25 percent at September 30, 2013 and December 31, 2012.

(In millions)	September 30, 2013	December 31, 2012
Commercial paper	$200	$200
Long-term debt due within one year	68	184
Long-term debt	6,433	6,512
Total debt	$6,701	$6,896
Cash	$354	$684
Equity	$18,994	$18,283
Calculation:		
Total debt	$6,701	$6,896
Minus cash	354	684
Total debt minus cash	6,347	6,212
Total debt	6,701	6,896
Plus equity	18,994	18,283
Minus cash	354	684
Total debt plus equity minus cash	$25,341	$24,495
Cash-adjusted debt-to-capital ratio	25 %	25 %

Capital Requirements

On October 30, 2013, our Board of Directors approved a dividend of 19 cents per share for the third quarter of 2013, payable December 10, 2013 to stockholders of record at the close of business on November 20, 2013.

As of September 30, 2013, we plan to make contributions of up to $17 million to our funded pension plans during the remainder of 2013.

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of September 30, 2013, we had repurchased 92 million common shares at a cost of $3,722 million, with 66 million shares purchased for $2,922 million prior to the spin-off of our downstream business, 12 million shares acquired at a cost of $300 million in the third quarter of 2011 and 14 million shares acquired at a cost of $500 million during the third quarter of 2013. An additional $500 million repurchase of common shares is anticipated to be completed after closing the previously discussed sale of our interest in Angola Block 31, which is expected in the fourth quarter of 2013. 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.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies. The discussion of liquidity above also contains forward-looking statements regarding the timing of closing the sales of our interests in Angola Blocks 31 and 32, including the use of proceeds, and the timing and amount of repurchasing additional common stock. The timing of closing the sale of our interest in Angola Block 31 is subject to the satisfaction of customary closing conditions and obtaining necessary government and regulatory approvals. The sale of our interest in Angola Block 32 is subject to the execution of definitive agreements and obtaining necessary government approval. The expectations with respect to the use of proceeds from the sale of our interests in Angola Block 31 and 32 and the timing and amount of repurchasing additional common stock could be affected by changes in the prices and demand for liquid hydrocarbons and natural gas, actions of competitors, disruptions or interruptions of our exploration or production operations, unforeseen hazards such as weather conditions or acts of war or terrorist acts and other operating and economic considerations. The discussion of liquidity above also contains forward-looking statements regarding planned funding of pension plans, which are based on current expectations, estimates and projections and are not guarantees of actual performance.

Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for liquid hydrocarbons and natural gas, actions of competitors, disruptions or interruptions of our production or oil sands mining and bitumen upgrading operations due to unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other operating and economic considerations.

Contractual Cash Obligations

As of September 30, 2013, our total contractual cash obligations were consistent with December 31, 2012.

Environmental Matters

We have incurred and will continue to incur substantial 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, 2012.

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.

See Part II Item 1. Legal Proceedings for updated information about ongoing litigation.

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 2012 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.

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent increases and decreases in commodity prices on our open commodity derivative instruments, by contract type as of September 30, 2013 is provided in the following table.

	Incremental Change in IFO from a Hypothetical Price Increase of		Incremental Change in IFO from a Hypothetical Price Decrease of	
	10%	25%	10%	25%
Crude oil				
Swaps	$43	$108	$(43)	$(108)
Option Collars	(17)	(55)	14	50
Total crude oil	$26	$53	$(29)	$(58)

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, 2013 is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities): [a]		
Interest rate swap agreements	$11 [b]	$5
Long-term debt, including amounts due within one year	$(6,941) [b]	$(236)

(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.

The aggregate cash flow effect on foreign currency derivative contracts of a hypothetical 10 percent change in exchange rates at September 30, 2013 would be $52 million.

Item 4. Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our company's design and operation of disclosure controls and procedures were effective as of September 30, 2013.

In the first quarter of 2013, we completed the update of our existing Enterprise Resource Planning ("ERP") system. This update included a new general ledger, consolidations system and reporting tools. During the quarter ended September 30, 2013, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Segment Income				
North America E&P	$242	$107	$404	$281
International E&P	321	405	1,156	1,185
Oil Sands Mining	106	66	164	154
Segment income	669	578	1,724	1,620
Items not allocated to segments, net of income taxes	(100)	(128)	(346)	(360)
Net income	$569	$450	$1,378	$1,260
Capital Expenditures[a]				
North America E&P	$831	$1,045	$2,705	$2,887
International E&P	254	229	720	569
Oil Sands Mining	65	41	207	136
Corporate	12	24	57	87
Total	$1,162	$1,339	$3,689	$3,679
Exploration Expenses				
North America E&P	$48	$140	$559	$393
International E&P	105	30	192	84
Total	$153	$170	$751	$477

[a] 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	2013	2012	2013	2012
North America E&P				
Crude Oil and Condensate (mbbld)	126	98	125	88
Natural Gas Liquids (mbbld)	24	13	22	10
Total Liquid Hydrocarbons	150	111	147	98
Natural Gas (mmcfd)	297	366	318	343
Total North America E&P (mboed)	200	172	200	155
International E&P				
Liquid Hydrocarbons (mbbld)				
Europe	81	94	91	97
Africa	57	88	73	73
Total Liquid Hydrocarbons	138	182	164	170
Natural Gas (mmcfd)				
Europe[(b)]	69	100	84	102
Africa	493	485	464	434
Total Natural Gas	562	585	548	536
Total International E&P (mboed)	231	280	255	259
Oil Sands Mining				
Synthetic Crude Oil (mbbld)[(c)]	49	53	47	47
Total Company (mboed)	480	505	502	461
Net Sales Volumes of Equity Method Investees				
LNG (mtd)	7,302	7,065	6,638	6,277
Methanol (mtd)	1,364	1,146	1,249	1,242

(b) Includes natural gas acquired for injection and subsequent resale of 4 mmcfd and 18 mmcfd for the third quarters of 2013 and 2012, and 8 mmcfd and 16 mmcfd for thefirst nine months of 2013 and 2012.

(c) Includes blendstocks.

38

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
Average Realizations	2013	2012	2013	2012
North America E&P				
Crude Oil and Condensate (per bbl)	$101.05	$89.89	$96.54	$92.00
Natural Gas Liquids (per bbl)	$35.01	$37.88	$34.06	$41.99
Total Liquid Hydrocarbons[d]	$90.49	$83.56	$87.09	$87.07
Natural Gas (per mcf)	$3.51	$3.61	$3.86	$3.73
International E&P				
Liquid Hydrocarbons (per bbl)				
Europe	$113.73	$112.34	$112.12	$115.73
Africa	$84.58	$98.65	$92.26	$97.00
Total Liquid Hydrocarbons	$101.68	$105.71	$103.25	$107.69
Natural Gas (per mcf)				
Europe	$11.61	$10.10	$11.98	$10.05
Africa[e]	$0.59	$0.63	$0.53	$0.39
Total Natural Gas	$1.95	$2.25	$2.29	$2.23
Oil Sands Mining				
Synthetic Crude Oil (per bbl)	$102.64	$81.13	$90.65	$83.58

(d) Inclusion of realized gains (losses) on crude oil derivative instruments would have decreased average liquid hydrocarbon realizations by $1.81 per bbl and $0.30 per bbl for the third quarter and first nine months of 2013. There were no realized gains (losses) on crude oil derivative instruments in the same periods of 2012.

(e) 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. Certain of those matters are discussed below.

Litigation

In March 2011, Noble Drilling (U.S.) LLC ("Noble") filed a lawsuit against us in the District Court of Harris County, Texas, alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. In April 2013, we filed a counterclaim against Noble alleging, among other things, breach of contract and breach of the duty of good faith relating to the multi-year drilling contract. The counterclaim also included a breach of contract claim for reimbursement for the value of fuel used by Noble under an offshore daywork drilling contract. The parties have reached a tentative settlement of this litigation. We believe that the settlement of this litigation will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The discussion of such risks and uncertainties may be found under Item 1A. Risk Factors in our 2012 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, 2013, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934.

Period	Column (a) Total Number of Shares Purchased [a][b]	Column (b) Average Price Paid per Share	Column (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[c]	Column (d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[c]
07/01/13 - 07/31/13	10,481	$35.24	—	$1,780,609,536
08/01/13 - 08/31/13	3,253	$37.18	—	$1,780,609,536
09/01/13 - 09/30/13	14,281,443	$35.53	14,066,840	$1,280,820,541
Total	14,295,177	$35.52	14,066,840	

(a) 201,089 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In September 2013, 27,248 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) We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of September 30, 2013, 92 million split-adjusted common shares had been acquired at a cost of $3,722 million, which includes transaction fees and commissions that are not reported in the table above. Of this total, 66 million shares had been acquired at a cost of $2,922 million prior to the spin-off of the downstream business.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

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

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.1	Form of Initial CEO Option Grant Agreement granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan.					X	
10.2	Form of CEO Restricted Stock Agreement granted under Marathon Oil Corporation's 2012 Incentive Compensation Plan (3-year prorata vesting).					X	
10.3							