NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 30, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2014
OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from to .

Commission File Number: 1-12534

NEWFIELD EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	72-1133047
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

4 Waterway Square Place
Suite 100
The Woodlands, Texas 77380
(Address and Zip Code of principal executive offices)

(281) 210-5100
(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 þ 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) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ 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. (Check one):

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨

(Do not check if a smaller reporting company)

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

As of July 28, 2014, there were 136,653,324 shares of the registrant's common stock, par value $0.01 per share, outstanding.

TABLE OF CONTENTS

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except share data)
(Unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$36	$95
Restricted cash	—	90
Accounts receivable	384	474
Inventories	41	163
Deferred taxes	34	22
Other current assets	33	57
Total current assets	528	901
Oil and gas properties — full cost method ($1,398 and $1,300 were excluded from amortization at June 30, 2014 and December 31, 2013, respectively)	15,876	16,407
Less — accumulated depreciation, depletion and amortization	(7,691)	(8,306)
Total oil and gas properties, net	8,185	8,101
Other property and equipment, net	180	174
Derivative assets	5	26
Long-term investments	26	63
Deferred taxes	—	19
Other assets	32	37
Total assets	$8,956	$9,321
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$51	$76
Accrued liabilities	879	978
Deferred liabilities	—	90
Advances from joint owners	27	30
Asset retirement obligations	5	54
Derivative liabilities	167	62
Total current liabilities	1,129	1,290
Other liabilities	35	38
Derivative liabilities	58	—
Long-term debt	3,077	3,694
Asset retirement obligations	108	201
Deferred taxes	1,307	1,142
Total long-term liabilities	4,585	5,075
Commitments and contingencies (Note 12)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
	1	1

Common stock ($0.01 par value, 200,000,000 shares authorized at June 30, 2014 and December 31, 2013; 136,828,201 and 136,682,631 shares issued at June 30, 2014 and December 31, 2013, respectively)		
Additional paid-in capital	1,556	1,539
Treasury stock (at cost, 206,109 and 460,914 shares at June 30, 2014 and December 31, 2013, respectively)	(6)	(13)
Accumulated other comprehensive gain (loss)	2	2
Retained earnings	1,689	1,427
Total stockholders' equity	3,242	2,956
Total liabilities and stockholders' equity	$8,956	$9,321

The accompanying notes to consolidated financial statements are an integral part of this statement.

1

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF OPERATIONS
(In millions, except per share data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Oil, gas and NGL revenues	$608	$435	$1,161	$805
Operating expenses:				
Lease operating	119	107	230	195
Production and other taxes	29	21	54	33
Depreciation, depletion and amortization	212	164	400	311
General and administrative	68	54	124	99
Total operating expenses	428	346	808	638
Income from operations	180	89	353	167
Other income (expense):				
Interest expense	(51)	(50)	(102)	(101)
Capitalized interest	13	13	26	27
Commodity derivative income (expense)	(174)	117	(270)	33
Other, net	1	2	3	4
Total other income (expense)	(211)	82	(343)	(37)
Income (loss) from continuing operations before income taxes	(31)	171	10	130
Income tax provision (benefit):				
Current	—	—	—	—
Deferred	(8)	65	9	49
Total income tax provision (benefit)	(8)	65	9	49
Income (loss) from continuing operations	(23)	106	1	81
Income (loss) from discontinued operations, net of tax	1	5	261	22
Net income (loss)	$(22)	$111	$262	$103
Earnings (loss) per share:				
Basic:				
Income (loss) from continuing operations	$(0.16)	$0.78	$0.01	$0.60
Income (loss) from discontinued operations	—	0.04	1.91	0.16
Basic earnings (loss) per share	$(0.16)	$0.82	$1.92	$0.76
Diluted:				
Income (loss) from continuing operations	$(0.16)	$0.78	$0.01	$0.60
Income (loss) from discontinued operations	—	0.04	1.89	0.16
Diluted earnings (loss) per share	$(0.16)	$0.82	$1.90	$0.76
Weighted-average number of shares outstanding for basic earnings (loss) per share	136	135	136	135
Weighted-average number of shares outstanding for diluted earnings (loss) per share	136	136	138	136

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$(22)	$111	$262	$103
Other comprehensive income (loss):				
Unrealized gain (loss) on investments, net of tax	—	1	—	3
Other comprehensive income (loss), net of tax	—	1	—	3
Comprehensive income (loss)	$(22)	$112	$262	$106

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)
(Unaudited)

	Six Months Ended June 30, 2014	2013
Cash flows from operating activities:		
Net income (loss)	$262	$103
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	437	439
Deferred tax provision (benefit)	153	68
Stock-based compensation	35	17
Commodity derivative (income) expense	270	(33)
Cash receipts (payments) related to derivative contracts, net	(86)	35
Gain on sale of Malaysia business	(388)	—
Other, net	(2)	4
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	76	(14)
(Increase) decrease in inventories	(6)	20
(Increase) decrease in other current assets	(5)	8
(Increase) decrease in other assets	1	2
Increase (decrease) in accounts payable and accrued liabilities	(14)	(40)
Increase (decrease) in advances from joint owners	(2)	5
Increase (decrease) in other liabilities	2	(4)
Net cash provided by (used in) operating activities	733	610
Cash flows from investing activities:		
Additions to oil and gas properties	(1,004)	(876)
Acquisitions of oil and gas properties	(15)	(3)
Proceeds from sales of oil and gas properties	12	19
Proceeds received from sale of Malaysia business, net	809	—
Additions to other property and equipment	(17)	(14)
Redemptions of investments	39	1
Net cash provided by (used in) investing activities	(176)	(873)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	1,134	1,425
Repayments of borrowings under credit arrangements	(1,752)	(1,194)
Debt issue costs	—	(4)
Proceeds from issuances of common stock	2	1
Purchases of treasury stock, net	—	(2)
Net cash provided by (used in) financing activities	(616)	226
Increase (decrease) in cash and cash equivalents	(59)	(37)
Cash and cash equivalents, beginning of period	95	88
Cash and cash equivalents, end of period	$36	$51

The accompanying notes to consolidated financial statements are an integral part of this statement.

4

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Gain (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2013	136.7	$1	(0.5)	$(13)	$1,539	$1,427	$ 2	$2,956
Issuances of common stock	0.1	—			2			2
Stock-based compensation					22			22
Treasury stock, net			0.3	7	(7)			—
Net income						262		262
Balance, June 30, 2014	136.8	$1	(0.2)	$(6)	$1,556	$1,689	$ 2	$3,242

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids (NGLs). Our principal areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast regions of North America.

Our consolidated financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and natural gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to “Newfield,” “we,” “us,” “our” or the “Company” are to Newfield Exploration Company and its subsidiaries.

These unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to fairly state our financial position as of and results of operations for the periods presented. These financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America. Interim period results are not necessarily indicative of results of operations or cash flows for a full year.

These consolidated financial statements and notes should be read in conjunction with our audited consolidated financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2013.

Discontinued Operations

Our businesses in Malaysia and China were classified as held for sale in the second quarter of 2013. Accordingly, the results of our international operations are reflected separately as discontinued operations in the consolidated statement of operations on a line immediately after “Income (loss) from continuing operations.” See Note 3, “Discontinued Operations,” for additional disclosures, as well as information regarding the sale of our Malaysia business, which closed in February 2014. These financial statements and notes are inclusive of our international operations unless otherwise noted.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities; disclosure of contingent assets and liabilities at the date of the financial statements; the reported amounts of revenues and expenses during the reporting period; and the quantities and values of proved oil, natural gas and NGL reserves used in calculating depletion and assessing impairment of our oil and gas properties. Actual results could differ significantly from these estimates. Our most significant estimates are associated with the quantities of proved oil, natural gas and NGL reserves and the fair value of our derivative positions and our stock-based compensation liability awards.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform to the current year presentation. These reclassifications did not impact our net income (loss), stockholders' equity or cash flows.

Restricted Cash and Deferred Liabilities

Restricted cash and the associated deferred liability on our consolidated balance sheet at December 31, 2013, represent a deposit received in the fourth quarter of 2013 related to the sale of our Malaysia business. Amounts were contractually restricted until the transaction closed on February 10, 2014. See Note 3, "Discontinued Operations," for further discussion about the close of the sale of our Malaysia business.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits, interest and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized approximately $65 million and $50 million of interest and direct internal costs during the three-month periods ended June 30, 2014 and 2013, respectively, and $120 million and $100 million during the six-month periods ended June 30, 2014 and 2013, respectively.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. During the first quarter of 2014, we recognized a gain of approximately $388 million ($249 million, after tax) on the sale of our Malaysia business, which constituted the entire full cost pool for Malaysia. See Note 3, "Discontinued Operations," for further discussion.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown reduces earnings and stockholders' equity in the period of occurrence and, holding other factors constant, results in lower depreciation, depletion and amortization expense in future periods. We did not have a ceiling test writedown in any periods presented.

New Accounting Requirements

In June 2014, the FASB issued guidance regarding stock-based compensation awards with targets that affect vesting and that could be achieved after the requisite service period. The guidance applies on a prospective basis to awards that are granted or modified on or after the effective date. The guidance is effective for annual periods beginning after December 15, 2015, and interim periods within those annual periods. We do not expect adoption of this guidance to have a material impact on our financial position or results of operations.

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings. The guidance is effective for interim and annual periods beginning on or after December 15, 2016. We are currently evaluating the impact of this guidance on our financial statements.

In April 2014, the FASB issued guidance regarding the reporting of discontinued operations. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. The guidance is effective for interim and annual periods beginning on or after December 15, 2014. We do not expect adoption of this guidance to have a material impact on our financial position or results of operations.

Table of Contents
NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

2. Earnings Per Share:

The following is the calculation of basic and diluted weighted-average shares outstanding and earnings per share (EPS) for the indicated periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions, except per share data)			
Income (numerator):				
Income (loss) from continuing operations	$(23)	$106	$1	$81
Income (loss) from discontinued operations, net of tax	1	5	261	22
Net income (loss)	$(22)	$111	$262	$103
Weighted-average shares (denominator):				
Weighted-average shares — basic	136	135	136	135
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period[(1) (2)]	—	1	2	1
Weighted-average shares — diluted	136	136	138	136
Earnings (loss) per share:				
Basic:				
Income (loss) from continuing operations	$(0.16)	$0.78	$0.01	$0.60
Income (loss) from discontinued operations	—	0.04	1.91	0.16
Basic earnings (loss) per share	$(0.16)	$0.82	$1.92	$0.76
Diluted:				
Income (loss) from continuing operations	$(0.16)	$0.78	$0.01	$0.60
Income (loss) from discontinued operations	—	0.04	1.89	0.16
Diluted earnings (loss) per share	$(0.16)	$0.82	$1.90	$0.76

(1) Excludes 0.8 million shares of unvested restricted stock or restricted stock units and stock options for the six months ended June 30, 2014 and 3.4 million and 3.7 million shares for the three and six months ended June 30, 2013 because including the effect would have been anti-dilutive.

(2) The effect of unvested restricted stock or restricted stock units and stock options has not been included in the calculation of the shares outstanding for diluted EPS for the three months ended June 30, 2014, as their effect would have been anti-dilutive. Had we recognized income from continuing operations for this period, incremental shares attributable to the assumed vesting of unvested restricted stock and restricted stock units and the assumed exercise of outstanding stock options would have increased diluted weighted-average shares outstanding by 1.6 million shares for the three months ended June 30, 2014.

3. Discontinued Operations:

Malaysia Update

In February 2014, Newfield International Holding Inc., a wholly-owned subsidiary of the Company, closed the stock purchase agreement to sell our Malaysia business to SapuraKencana Petroleum Berhad, a Malaysian public company, for $898 million (subject to customary purchase price adjustments). We recorded a gain in the first quarter of 2014 of approximately $388 million ($249 million, after tax).

China Update

In August 2013, during the installation of the LF-7 topside facilities by a third-party contractor, a hydraulic jacking system malfunctioned and the installation was suspended. Activities are substantially complete to repair the damage to the jacket. Subject to favorable weather conditions, we plan to install the LF-7 topside facilities in the third quarter of 2014 and expect to achieve first oil production in late 2014. We continue to pursue the sale of our China business.

Income from discontinued operations from our China business was $1 million ($1 million, net of tax) for the three months ended June 30, 2014 and $10 million ($3 million, net of tax) for the six months ended June 30, 2014. Income from discontinued operations from our China business was $4 million ($1 million, net of tax) for the three months ended June 30, 2013 and $17 million ($5 million, net of tax) for the six months ended June 30, 2013.

Results of Discontinued Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Oil and gas revenues[1]	$4	$188	$112	$470
Operating expenses	3	159	81	373
Income from discontinued operations	1	29	31	97
Other income (expense)	—	(1)	—	(1)
Gain on sale of Malaysia business	—	—	388	—
Income from discontinued operations before income taxes	1	28	419	96
Income tax provision (benefit):				
Current	—	6	14	55
Deferred	—	17	144	19
Total income tax provision (benefit)[2]	—	23	158	74
Income from discontinued operations, net of tax	$1	$5	$261	$22

(1) Certain payments to foreign governments made on our behalf that are part of the revenue process are recorded as a reduction of the related oil and gas revenues.
(2) Total income taxes rounded to zero for the three months ended June 30, 2014.

Income Taxes

Historically, our international effective tax rate has been approximately 37%. As a result of our December 2012 decision to repatriate earnings from our international operations, we have experienced higher international effective tax rates due to these earnings being taxed both in the U.S. and the local countries. We expect this to continue until we are fully divested of our international businesses. For the six months ended June 30, 2014, our effective tax rate was 37.9% as the majority of our income from discontinued operations resulted from the gain on the sale of our Malaysia business, which was only taxable in the U.S. The effective tax rate for our discontinued operations for the three months ended June 30, 2013 was 81.1% and for the six months ended June 30, 2013 was 76.7% due to our international earnings being taxed both in the U.S and the local country.

Assets and Liabilities in the Consolidated Balance Sheet Attributable to Discontinued Operations

	June 30, 2014	December 31, 2013
	(In millions)	
Current assets:		
Cash and cash equivalents	$31	$84
Accounts receivable	82	200
Inventories	12	130
Other current assets	6	33
Total current assets	131	447
Noncurrent assets:		
Oil and gas properties, net of accumulated depreciation, depletion and amortization of $116 and $1,121 as of June 30, 2014 and December 31, 2013, respectively	503	989
Deferred taxes	—	19
Other assets	1	4
Total noncurrent assets	504	1,012
Total assets	$635	$1,459
Current liabilities:		
Accounts payable	$3	$38
Accrued liabilities	191	324
Asset retirement obligations	—	49
Other current liabilities	—	18
Total current liabilities	194	429
Noncurrent liabilities:		
Asset retirement obligations	2	86
Deferred taxes	105	129
Other liabilities	—	11
Total noncurrent liabilities	107	226
Total liabilities	$301	$655

Inventories

Substantially all of the crude oil from our international offshore operations is produced into floating production, storage and off-loading vessels (FPSOs) and “lifted” and sold periodically as barge quantities are accumulated. At December 31, 2013, the crude oil inventory from our Malaysia and China operations consisted of approximately 1.1 million barrels of crude oil valued at cost of $90 million and is included in the "Inventories" line item in the preceding table and in our consolidated balance sheet. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion expense. The sale of our Malaysia business in February 2014 reduced crude oil inventory to a de minimis amount. Remaining inventories at June 30, 2014 primarily consisted of tubular goods and well equipment for use in our oil and natural gas operations in China.

Oil and Gas Properties

As of June 30, 2014, all of our oil and gas properties in our discontinued operations were subject to amortization. As of December 31, 2013, approximately $115 million of our oil and gas properties in our discontinued operations were not subject to amortization.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Asset Retirement Obligations

During the six months ended June 30, 2014, asset retirement obligations were reduced by $133 million as a result of the sale of our Malaysia business in February 2014.

4. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following:

	June 30, 2014	December 31, 2013
	(In millions)	
Oil and gas properties:		
Subject to amortization	$14,478	$15,107
Not subject to amortization	1,398	1,300
Gross oil and gas properties	15,876	16,407
Accumulated depreciation, depletion and amortization	(7,691)	(8,306)
Net oil and gas properties	$8,185	$8,101
Other property and equipment:		
Furniture, fixtures and equipment	149	139
Gathering systems and equipment	109	104
Accumulated depreciation and amortization	(78)	(69)
Net other property and equipment	$180	$174

Oil and gas properties not subject to amortization as of June 30, 2014, consisted of the following:

	Costs Incurred In				
	2014	2013	2012	2011 and Prior	Total
	(In millions)				
Acquisition costs	$84	$199	$96	$430	$809
Exploration costs	301	19	2	7	329
Development costs	16	8	31	16	71
Fee mineral interests	—	1	—	23	24
Capitalized interest	26	53	67	19	165
Total oil and gas properties not subject to amortization	$427	$280	$196	$495	$1,398

5. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize derivative strategies that consist of either a single derivative instrument or a combination of instruments to manage the variability in cash flows associated with the forecasted sale of our future domestic oil and natural gas production. While the use of derivative instruments limits the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements.

Our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, estimated volatility, non-performance risk adjustments using credit default swaps and time to maturity. The calculation of the fair value of options requires the use of an option-pricing model. See Note 8, “Fair Value Measurements.”

At June 30, 2014, we had outstanding derivative positions as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu				
				Collars		
Period and Type of Instrument	Volume in MMMBtus	Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
2014:						
Fixed-price swaps	43,240	$3.98	—	—	—	$(21)
Collars	11,960	—	—	$3.75	$4.62	(2)
2015:						
Fixed-price swaps	49,275	4.28	—	—	—	3
Collars	38,325	—	—	3.93	4.74	1
Total						$(19)

Crude Oil

		NYMEX Contract Price Per Bbl				
				Collars		
Period and Type of Instrument	Volume in MBbls	Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
2014:						
Fixed-price swaps	4,048	$89.91	—	—	—	$(54)
Fixed-price swaps with sold puts	2,944	95.16	$75.00	—	—	(24)
Collars with sold puts	1,104	—	75.83	$90.83	$102.93	(4)
2015:						
Fixed-price swaps	8,115	90.37	—	—	—	(53)
Fixed-price swaps with sold puts	6,989	90.19	69.47	—	—	(47)
Collars with sold puts	365	—	75.00	90.00	103.50	—
2016:						
Fixed-price swaps with sold puts	6,766	91.01	74.53	—	—	(16)
Collars with sold puts	4,938	—	75.00	90.00	95.86	(2)
2017:						
Fixed-price swaps with sold puts	450	91.52	75.00	—	—	(1)
Collars with sold puts	813	—	75.00	90.00	94.93	—
Total						$(201)

Table of Contents
NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Additional Disclosures about Derivative Instruments

We had derivative financial instruments recorded in our consolidated balance sheet as assets (liabilities) at their respective estimated fair value, as set forth below.

	Derivative Assets		Balance Sheet Location		Derivative Liabilities		Balance Sheet Location	
	Gross Fair Value	Offset in Balance Sheet	Current	Noncurrent	Gross Fair Value	Offset in Balance Sheet	Current	Noncurrent
	(In millions)				(In millions)			
June 30, 2014								
Natural gas positions	$5	$—	$—	$5	$(24)	$—	$(24)	$—
Oil positions	8	(8)	—	—	(209)	8	(143)	(58)
Total	$13	$(8)	$—	$5	$(233)	$8	$(167)	$(58)
December 31, 2013								
Natural gas positions	$11	$(2)	$—	$9	$(22)	$2	$(20)	$—
Oil positions	26	(9)	—	17	(51)	9	(42)	—
Total	$37	$(11)	$—	$26	$(73)	$11	$(62)	$—

The amount of gain (loss) recognized in “Commodity derivative income (expense)” in our consolidated statement of operations related to our derivative financial instruments follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Derivatives not designated as hedging instruments:				
Realized gain (loss) on natural gas positions	$(12)	$5	$(34)	$32
Realized gain (loss) on oil positions	(35)	3	(52)	3
Total realized gain (loss)	(47)	8	(86)	35
Unrealized gain (loss) on natural gas positions	9	70	(8)	(18)
Unrealized gain (loss) on oil positions	(136)	39	(176)	16
Total unrealized gain (loss)	(127)	109	(184)	(2)
Total	$(174)	$117	$(270)	$33

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty, and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty. At June 30, 2014, 10 of our 16 counterparties accounted for approximately 85% of our contracted volumes, with no single counterparty accounting for more than 15%.

A portion of our derivative instruments are with lenders under our credit facility. Our credit facility, senior notes, senior subordinated notes and substantially all of our derivative instruments contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

6. Accounts Receivable:

Accounts receivable consisted of the following:

	June 30, 2014	December 31, 2013
	(In millions)	
Revenue	$190	$294
Joint interest	159	156
Other	36	25
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$384	$474

7. Accrued Liabilities:

Accrued liabilities consisted of the following:

	June 30, 2014	December 31, 2013
	(In millions)	
Revenue payable	$182	$175
Accrued capital costs	451	458
Accrued lease operating expenses	30	71
Employee incentive expense	65	64
Accrued interest on debt	73	72
Taxes payable	27	93
Other	51	45
Total accrued liabilities	$879	$978

8. Fair Value Measurements:

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value and requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity fixed-price swaps and certain investments.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Level 3 instruments primarily include derivative instruments, such as commodity options (i.e., price collars, sold puts or swaptions) and other financial investments.

Table of Contents
NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

- Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments.

- Our valuation model for the Stockholder Value Appreciation Program (SVAP) is a Monte Carlo simulation that is based on a probability model and considers various inputs including: (a) the measurement date stock price, (b) time value and (c) historical and implied volatility. See Note 11, "Stock-Based Compensation," for a description of the SVAP.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy.

Recurring Fair Value Measurements

The following table summarizes the valuation of our assets and liabilities that are measured at fair value on a recurring basis.

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In millions)			
As of December 31, 2013:				
Money market fund investments	$2	$—	$—	$2
Deferred compensation plan assets	8	—	—	8
Investments available-for-sale:				
Equity securities	8	—	—	8
Auction rate securities	—	—	39	39
Oil and gas derivative swap contracts	—	(28)	—	(28)
Oil and gas derivative option contracts	—	—	(8)	(8)
Stock-based compensation liability awards	(11)	—	(5)	(16)
Total	$7	$(28)	$26	$5
As of June 30, 2014:				
Money market fund investments	$1	$—	$—	$1
Deferred compensation plan assets	9	—	—	9
Equity securities available-for-sale	9	—	—	9
Oil and gas derivative swap contracts	—	(196)	—	(196)
Oil and gas derivative option contracts	—	—	(24)	(24)
	(19)	—	(46)	(65)

Stock-based compensation liability awards				
Total	$—	$(196)	$(70)	$(266)

The determination of the fair values above incorporates various factors, which include not only the impact of our non-performance risk on our derivative liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), if any. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

As of December 31, 2013, we held $39 million of auction rate securities, which were classified as a Level 3 fair value measurement. During the first quarter of 2014, all auction rate securities were sold for $39 million.

15

Level 3 Fair Value Measurements

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods.

	Investments	Derivatives	Stock-based Compensation	Total
	(In millions)			
Balance at January 1, 2013	$36	$115	$ —	$151
Realized or unrealized gains (losses):				
Included in earnings	—	(41)	—	(41)
Included in other comprehensive income (loss)	4	—	—	4
Purchases, issuances, sales and settlements:				
Settlements	(1)	(32)	—	(33)
Transfers in to Level 3	—	—	—	—
Transfers out of Level 3	—	—	—	—
Balance at June 30, 2013	$39	$42	$ —	$81
Change in unrealized gains or losses included in earnings relating to Level 3 instruments still held at June 30, 2013	$—	$5	$ —	$5
Balance at January 1, 2014	$39	$(8)	$ (5)	$26
Realized or unrealized gains (losses) included in earnings	—	(23)	(54)	(77)
Purchases, issuances, sales and settlements:				
Sales	(39)	—	—	(39)
Settlements	—	4	13	17
Transfers in to Level 3	—	—	—	—
Transfers out of Level 3	—	3	—	3
Balance at June 30, 2014	$—	$(24)	$ (46)	$(70)
Change in unrealized gains or losses included in earnings relating to Level 3 instruments still held at June 30, 2014	$—	$(17)	$ (28)	$(45)

During the second quarter of 2014, we transferred $3 million of derivative option contracts out of the Level 3 hierarchy. The transfer was a result of our Level 3 swaptions being exercised by the counterparties as swaps on May 30, 2014.

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Derivatives. Our valuation models for Level 3 derivative contracts are primarily industry-standard models that consider various factors, including certain significant unobservable inputs such as (a) quoted forward prices for commodities, (b) volatility factors and (c) counterparty credit risk. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the strike prices fixed by our derivative contracts, and the resulting estimated future cash inflows or outflows over the contractual life are discounted to calculate the fair value. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. Significant increases (decreases) in the quoted forward prices for commodities generally lead to corresponding decreases (increases) in the fair value measurement of our oil and gas derivative contracts. Significant changes in the volatility factors utilized in our option-pricing model can cause significant changes in the fair value measurement of our oil and gas derivative contracts.

The determination of the fair values of derivative instruments incorporates various factors that include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests). Historically, we have not experienced significant changes in the fair value of our derivative contracts resulting from changes in counterparty credit risk as the counterparties for all of our derivative transactions have an “investment grade” credit rating.

Stock-Based Compensation. The calculation of the fair value of the SVAP liability requires the use of a probability-based Monte Carlo simulation, which includes unobservable inputs. The simulation predicts multiple scenarios of future stock returns over the performance period, which are discounted to calculate the fair value. The fair value is recognized over a service period derived from the simulation. Future stock returns and discounting variables are sensitive to market volatility. Significant increases (decreases) in the volatility factors utilized in our option-pricing model can cause significant increases (decreases) in the fair value measurement of the SVAP liability.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Estimated Fair Value Asset (Liability) (In millions)	Quantitative Information about Level 3 Fair Value Measurements Valuation Technique	Unobservable Input	Range
Oil option contracts	$(23)	Black-Scholes	Oil price volatility	11.76% — 52.25%
			Credit risk	0.01% — 3.11%
Natural gas option contracts	$(1)	Black-Scholes	Natural gas price volatility	20.77% — 49.14%
			Credit risk	0.01% — 0.90%
SVAP	$(46)	Monte Carlo	Implied volatility	34.5%

Fair Value of Debt

The estimated fair value of our notes, based on quoted prices in active markets (Level 1) as of the indicated dates, was as follows:

	June 30, 2014	December 31, 2013
	(In millions)	
5¾% Senior Notes due 2022	$834	$767
5 % Senior Notes due 2024	1,093	1,025
7 % Senior Subordinated Notes due 2018	610	624
6 % Senior Subordinated Notes due 2020	742	755

Any amounts outstanding under our credit arrangements as of the indicated dates are stated at cost, which approximates fair value. Please see Note 9, "Debt."

9. Debt:

Our debt consisted of the following:

	June 30, 2014	December 31, 2013
	(In millions)	
Senior unsecured debt:		
Revolving credit facility - LIBOR based loans	$—	$585
Money market lines of credit[(1)]	31	64
Total credit arrangements	31	649
5¾% Senior Notes due 2022	750	750
5 % Senior Notes due 2024	1,000	1,000
Total senior unsecured debt	1,781	2,399
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	700	700
Discount on notes	(4)	(5)
Total long-term debt	$3,077	$3,694

(1) Because capacity under our credit facility was available to repay borrowings under our money market lines of credit as of the indicated dates, amounts outstanding under these obligations, if any, are classified as long-term.

Credit Arrangements

We have a revolving credit facility that matures in June 2018 and provides borrowing capacity of $1.4 billion. As of June 30, 2014, the largest individual loan commitment by any lender was 14% of total commitments.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank, N.A. or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points, plus a margin that is based on a grid of our debt rating (75 basis points per annum at June 30, 2014) or (b) the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (175 basis points per annum at June 30, 2014).

Under our credit facility, we pay commitment fees on available but undrawn amounts based on a grid of our debt rating (30 basis points per annum at June 30, 2014). We incurred aggregate commitment fees under our current credit facility of approximately $1 million and $2 million for the three and six months ended June 30, 2014, respectively, which are recorded in “Interest expense” on our consolidated statement of operations. For the three and six months ended June 30, 2013, we incurred commitment fees under our current credit facility of approximately $1 million and $2 million, respectively.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns and goodwill impairments) to interest expense of at least 3.0 to 1.0. At June 30, 2014, we were in compliance with all of our debt covenants.

As of June 30, 2014, we had no letters of credit outstanding under our credit facility. Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at June 30, 2014).

Subject to compliance with the restrictive covenants in our credit facility, at June 30, 2014, we also had a total of $164 million of available borrowing capacity under our money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

The credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; inaccuracy of representations and warranties in any material respect; a change of control; or certain other material adverse changes in our business. Our senior notes and senior subordinated notes also contain standard events of default. If any of the foregoing defaults were to occur, our lenders under the credit facility could terminate future lending commitments, and our lenders under both the credit facility and our notes could declare the outstanding borrowings due and payable. In addition, our credit facility, senior notes, senior subordinated notes and substantially all of our derivative arrangements contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

10. Income Taxes:

The provision for income taxes for continuing operations for the indicated periods was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Amount computed using the statutory rate	$(10)	$60	$4	$46
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect	2	5	5	3
Total provision (benefit) for income taxes	$(8)	$65	$9	$49

The effective tax rates for continuing operations for the three months ended June 30, 2014 and 2013 were 27.4% and 38.1%, respectively. The effective tax rates for continuing operations for the six months ended June 30, 2014 and 2013 were 89.2% and 37.9%, respectively. Unrealized derivative gains and losses are treated differently for income tax purposes in the various state taxing jurisdictions to which we are subject. As a result, our effective tax rate fluctuates in periods with significant commodity price volatility.

As of June 30, 2014, we did not have a liability for uncertain tax positions, and as such, we had not accrued related interest or penalties. The tax years 2010 through 2013 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

11. Stock-Based Compensation:

Our stock-based compensation consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Equity awards	$11	$11	$22	$23
Liability awards:				
Stockholder Value Appreciation Program	40	—	54	—
Cash-settled restricted stock units	10	1	16	1
Total liability awards	50	1	70	1

Total stock-based compensation	61	12	92	24
Capitalized in oil and gas properties	(26)	(4)	(40)	(7)
Net stock-based compensation expense	$35	$8	$52	$17

As of June 30, 2014, we had approximately $104 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation awards. The full amount is expected to be recognized within four years.

Equity Awards

Equity awards consist of service-based and performance- or market-based restricted stock units, stock options and stock purchase options under the Employee Stock Purchase Plan.

Stock-based compensation classified as equity awards to employees and non-employee directors are currently granted under the 2011 Omnibus Stock Plan (2011 Plan). The fair value of grants is determined utilizing the Black-Scholes option-pricing model for stock options and a Monte Carlo lattice-based model for our performance- and market-based restricted stock and restricted stock units. Compensation expense for equity awards is expected to be recognized on a straight-line basis over the applicable remaining vesting periods.

Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity.

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted-Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at December 31, 2013	2,999	706	3,705	$33.31
Granted	311	339	650	23.41
Forfeited	(226)	(46)	(272)	32.06
Vested	(332)	—	(332)	43.55
Non-vested shares outstanding at June 30, 2014	2,752	999	3,751	$30.72

Stock Options. The following table provides information about stock option activity.

	Number of Shares Underlying Options	Weighted-Average Exercise Price per Share	Weighted-Average Grant Date Fair Value per Share	Weighted-Average Remaining Contractual Life	Aggregate Intrinsic Value(1)
	(In thousands)			(In years)	(In millions)
Outstanding at December 31, 2013	687	$39.68		1.9	$—
Granted	—	—	$—		
Exercised	(86)	28.82			1
Forfeited	(231)	40.03			
Outstanding at June 30, 2014	370	$41.98		2.3	$2
Exercisable at June 30, 2014	370	$41.98		2.3	$2

(1) The intrinsic value of a stock option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the option.

On June 30, 2014, the last reported sales price of our common stock on the New York Stock Exchange was $44.20 per share.

Employee Stock Purchase Plan. During the first six months of 2014, options to purchase approximately 92,000 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $5.96 per share. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 0.09%, an expected life of six months and weighted-average volatility of 34%.

Liability Awards

Liability awards consist of performance awards that are settled in cash instead of shares under the Stockholder Value Appreciation Program (SVAP) and cash-settled restricted stock units.

Stockholder Value Appreciation Program. In September 2013, the Compensation and Management Development Committee of the Board approved the SVAP, to be administered under the 2011 Omnibus Stock Plan. The SVAP pays substantially all full-time domestic, nonexecutive employees a cash payment based on a percentage of salary upon each incremental $5 increase in our 30-calendar day average share price. Each price threshold can be reached only once during the term of the program. The SVAP's performance period lasts through December 31, 2015.

The first price threshold that triggered a payment under the SVAP was $27.50 during the fourth quarter of 2013. The second and third price thresholds for the SVAP were $32.50 and $37.50, respectively, which were reached during the second quarter of 2014. The fourth price threshold for the SVAP was $42.50, which was reached in July 2014 and will result in a cash payment of approximately $13 million that will be paid to eligible employees in August 2014.

Based upon the expected duration of the SVAP performance period, $46 million has been accrued as of June 30, 2014. The total expected cost was determined using a Monte Carlo simulation assuming no dividends, a risk-free weighted-average interest rate of 0.25%, a plan term of 1.5 years and an average of implied and historical stock price volatility of 33%. An additional $13 million is expected to be recognized over the remaining term of the plan. Future changes in our stock price could cause the total cost of the plan to be significantly different than our estimates as of June 30, 2014.

Cash-Settled Restricted Stock Units. We also grant cash-settled restricted stock units to employees that vest over three years. The value of the awards, and the associated stock-based compensation expense, is based on the Company’s stock price at the end of each period. During the six months ended June 30, 2014, approximately 283,000 cash-settled restricted stock units vested and settled for approximately $7 million, all of which occurred during the first quarter of 2014. During the six months ended June 30, 2013, approximately 38,000 cash-settled restricted stock units vested and settled for approximately $1 million, all of which occurred during the first quarter of 2013. As of June 30, 2014, we had approximately 1.0 million cash-settled restricted stock units outstanding and related unrecognized stock-based compensation expense of approximately $19 million.

12. Commitments and Contingencies:

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

13. Supplemental Cash Flow Information:

	Six Months Ended June 30,	
	2014	2013
	(In millions)	
Non-cash items excluded from the statement of cash flows:		
(Increase) decrease in receivables for property sales	$1	$(9)

(Increase) decrease in receivables from sale of Malaysia business	(15)	—
(Increase) decrease in accrued capital expenditures	(4)	(51)
(Increase) decrease in asset retirement costs	13	(2)
Increase (decrease) in deferred liabilities	(90)	—

14. Related-Party Transactions:

Kevin M. Robinson, our Vice President — Asia through February 10, 2014, and Susan G. Riggs, our Treasurer, are minority owners of Huffco International L.L.C. (Huffco). In May 1997, before Mr. Robinson and Ms. Riggs joined the Company, we acquired from Huffco an entity now known as Newfield China, LDC, the owner of a 12% interest in a three-field unit located in Bohai Bay, offshore China. Huffco retained preferred shares of Newfield China that provided for dividend payments. During the third quarter of 2013, we purchased the outstanding preferred shares of Newfield China from Huffco for approximately $20 million, which was recorded as a charge against retained earnings.

15. Subsequent Events:

On July 29, 2014, we entered into an agreement to sell our Granite Wash assets for approximately $588 million (subject to customary purchase price adjustments). The sale of our Granite Wash assets will not significantly alter the relationship between capitalized costs and proved reserves and as such, all proceeds will be recorded as adjustments to our domestic full cost pool with no gain or loss recognized. We expect the transaction to close in September of 2014.

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

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast regions of North America.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and natural gas reserves to replace those reserves being produced. Our revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. Prices for oil, natural gas and NGLs fluctuate widely and affect:

- the amount of cash flows available for capital expenditures;

- our ability to borrow and raise additional capital; and

- the quantity of oil, natural gas and NGLs that we can economically produce.

Discontinued Operations

During the second quarter of 2013, our international businesses met the criteria to be classified as held for sale and reported as discontinued operations. As such, the results of operations for our international businesses are reflected as discontinued operations and discussed further in Note 3, "Discontinued Operations," to our consolidated financial statements appearing earlier in this report.

Malaysia. In February 2014, Newfield International Holdings Inc., a wholly-owned subsidiary of the Company, closed the sale of our Malaysia business to SapuraKencana Petroleum Berhad, a Malaysian public company, for $898 million (subject to customary purchase price adjustments). See Note 3, “Discontinued Operations,” to our consolidated financial statements appearing earlier in this report for additional information regarding the sale of our Malaysia business.

China. In August 2013, during the installation of the LF-7 topside facilities by a third-party contractor, a hydraulic jacking system malfunctioned and the installation was suspended. Activities are substantially complete to repair the damage to the jacket. Subject to favorable weather conditions, we plan to install the LF-7 topside facilities in the third quarter of 2014 and expect to achieve first oil production in late 2014. We continue to pursue the sale of our China business.

Results of Continuing Operations

Our continuing operations consist of exploration, development and production activities in the United States.

Revenues. Our revenues are primarily from the sale of oil, natural gas and NGLs and may vary significantly from period to period as a result of changes in commodity prices or volume of production sold.

Revenues from continuing operations of $608 million for the second quarter of 2014 were 39% higher than the comparable period of 2013. Approximately 55% of the increase was attributable to increases in oil production in our onshore Gulf Coast, Rocky Mountains and Mid-Continent regions of 47%, 32% and 29%, respectively. Higher realized oil prices contributed 17% to the total revenue variance. NGL production in the Mid-Continent, onshore Gulf Coast and Rocky Mountains regions increased 64%, 50% and 45%, respectively, during the three months ended June 30, 2014 over the comparable period of 2013. Our natural gas production was relatively flat as we continue to focus capital investments on higher-margin liquids production.

Revenues of $1.2 billion for the first six months of 2014 were 44% higher than the comparable period of 2013. More than half of the increase was attributable to increases in oil production in our onshore Gulf Coast, Mid-Continent and Rocky Mountains regions of 59%, 33% and 33%, respectively. Higher realized oil prices contributed 11% to the total revenue variance. Additionally, NGL production in the Mid-Continent, onshore Gulf Coast and Rocky Mountains regions increased 66%, 66% and 36%, respectively, during the six months ended June 30, 2014. Natural gas production was relatively flat; however, a 30% increase in realized natural gas prices during the period generated 17% of the total favorable revenue variance. The following table reflects our production from continuing operations and average realized commodity prices.

	Three Months Ended June 30, 2014	2013	Percentage Increase (Decrease)	Six Months Ended June 30, 2014	2013	Percentage Increase (Decrease)
Production:(1)						
Crude oil and condensate (MBbls)	4,535	3,399	33 %	8,656	6,364	36 %
Natural gas (Bcf)	30.5	29.7	3 %	58.5	58.1	1 %
NGLs (MBbls)	2,022	1,268	60 %	3,703	2,285	62 %
Total (MBOE)	11,639	9,617	21 %	22,105	18,329	21 %
Average Realized Prices:(2)						
Crude oil and condensate (per Bbl)	$90.19	$83.66	8 %	$88.41	$83.78	6 %
Natural gas (per Mcf)	4.32	3.74	16 %	4.48	3.45	30 %
NGLs (per Bbl)	31.11	29.06	7 %	34.29	28.87	19 %
Crude oil equivalent (per BOE)	52.18	45.28	15 %	52.51	43.94	20 %

(1) Excludes natural gas produced and consumed in operations of 2.6 Bcf and 2.2 Bcf during the three months ended June 30, 2014 and 2013, respectively, and 4.4 Bcf and 4.7 Bcf during the six months ended June 30, 2014 and 2013, respectively.

(2) Had we included the realized effects of derivative contracts, the average realized price for natural gas would have been $3.90 and $3.91 per Mcf for the three months ended June 30, 2014 and 2013, respectively, and $3.89 and $4.00 per Mcf for the six months ended June 30, 2014 and 2013, respectively. The average crude oil realized price would have been $82.46 and $84.52 per Bbl for the three months ended June 30, 2014 and 2013, respectively, and $82.37 and $84.31 for the six months ended June 30, 2014 and 2013, respectively. We did not have any derivative contracts associated with NGL production for the periods presented.

Production. Our second quarter 2014 total production from continuing operations increased 2,022 MBOE, or 21% compared to second quarter of 2013 primarily due to increased liquids production. Our domestic liquids production increased approximately 40% due to the success of our liquids-focused drilling programs. Natural gas production was relatively flat as a result of reduced investment in natural gas wells.

For the six months ended June 30, 2014, total production from continuing operations increased 21% compared to the same period of 2013, driven by a 43% increase in liquids production.

Operating Expenses. The following table presents information about our operating expenses for our continuing operations for the following periods:

	Unit-of-Production Three Months Ended June 30, 2014	2013	Percentage Increase (Decrease)	Total Amount Three Months Ended June 30, 2014	2013	Percentage Increase (Decrease)
	(Per BOE)			(In millions)		
Lease operating	$10.26	$11.24	(9)%	$119	$107	11 %
Production and other taxes	2.49	2.20	13 %	29	21	37 %
Depreciation, depletion and amortization	18.17	16.97	7 %	212	164	30 %
General and administrative	5.85	5.60	4 %	68	54	26 %
Total operating expenses	$36.77	$36.01	2 %	$428	$346	24 %

Our operating expenses for continuing operations for the three months ended June 30, 2014 increased 2% over the same period of 2013 stated on a per BOE basis. The primary reasons for the increase follow:

- Lease operating expense (LOE) decreased 9% per BOE as our production growth outpaced the increase in operating costs, a large part of which was attributable to lower natural gas transportation costs per BOE as more of our production is liquids.

- Production and other taxes increased $8 million or 37% in comparison to the second quarter of 2013. This increase is primarily due to the higher revenues associated with increased production volumes and increased realized prices. As a percentage of revenue, production and other taxes was substantially the same in both periods.

- Total depreciation, depletion and amortization (DD&A) increased 30% primarily due to a 21% increase in production during the second quarter of 2014 compared to the second quarter of 2013, combined with a 7% increase in the cost per unit-of-production.

- General and administrative (G&A) expenses per BOE increased 4% during the second quarter of 2014 compared to the second quarter of 2013, primarily due to increased employee-related expenses associated with our stock-based liability award programs as a result of the 41% increase in our stock price during the second quarter of 2014. These employee-related expenses increased $26 million period over period. For the three months ended June 30, 2014, we capitalized $50 million ($4.26 per BOE) of direct internal costs as compared to $25 million ($2.62 per BOE) during the comparable quarter of 2013. This increase is primarily related to capitalization of a portion of the costs associated with the stock-based liability awards.

	Unit-of-Production Six Months Ended June 30,		Percentage Increase (Decrease)		Total Amount Six Months Ended June 30,		Percentage Increase (Decrease)	
	2014	2013			2014	2013		
	(Per BOE)				(In millions)			
Lease operating	$ 10.41	$ 10.67	(2	)%	$ 230	$ 195	18	%
Production and other taxes	2.46	1.81	36	%	54	33	64	%
Depreciation, depletion and amortization	18.08	16.94	7	%	400	311	29	%
General and administrative	5.60	5.40	4	%	124	99	25	%
Total operating expenses	$ 36.55	$ 34.82	5	%	$ 808	$ 638	27	%

Our total operating expenses for continuing operations for the six months ended June 30, 2014 increased 5% as compared to the same period of 2013 stated on a per BOE basis. The primary reasons for the increase follow:

- Production and other taxes increased $21 million or 64% in comparison to the first six months of 2013. Higher revenues resulted in an increase in production and other taxes of approximately $17 million during the first half of 2014. On a per BOE basis, the increase was 36% and is driven by an increase in liquids production as a percent of total production and the associated increase in average revenue per BOE produced from $43.94 for the six months ended June 30, 2013, to $52.51 for the same period in 2014. As a percent of revenue, production and other taxes was 4.7% and 4.1% for the six- month periods ended June 30, 2014 and 2013, respectively. The increase is primarily due to non-recurring production tax credits in our Rocky Mountains region recorded during the first quarter of 2013.

- Total depreciation, depletion and amortization increased 29% primarily due to a 21% increase in production during the first six months of 2014 compared to the comparable period of 2013, combined with a 7% increase in the cost per unit-of-production.

- General and administrative expenses per BOE increased 4% during the first six months of 2014 compared to the comparable period in 2013, primarily due to increased employee-related expenses associated with our stock-based liability award programs as a result of the 79% increase in our stock price during the first six months of 2014. These employee-related expenses increased $37 million period over period. For the six months ended June 30, 2014, we capitalized $86 million ($3.88 per BOE) of direct internal costs as compared to $53 million ($2.91 per BOE) during the comparable period of 2013. This increase is primarily related to capitalization of a portion of the costs associated with the stock-based liability awards.

Interest Expense. The following table presents information about interest expense. Interest expense associated with unproved oil and gas properties is capitalized into oil and gas properties.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Gross interest expense:				
Credit arrangements	$2	$2	$5	$4
Senior notes	25	25	50	50
Senior subordinated notes	24	23	47	47
Total gross interest expense	51	50	102	101
Capitalized interest	(13)	(13)	(26)	(27)
Net interest expense	$38	$37	$76	$74

Commodity Derivative Income (Expense). The fluctuations in commodity derivative income from period to period are due to the volatility of oil and natural gas prices and changes in our outstanding derivative instruments during these periods.

Taxes. The effective tax rates for the three months ended June 30, 2014 and 2013 were 27.4% and 38.1%, respectively. The effective tax rates for the six months ended June 30, 2014 and 2013 were 89.2% and 37.9%, respectively. Unrealized derivative gains and losses are treated differently in the various state taxing jurisdictions to which we are subject. As a result, our effective tax rate fluctuates in periods with significant commodity price volatility.

Results of Discontinued Operations - Malaysia and China

Revenues and Liftings. Our international revenues are primarily from the sale of crude oil. Substantially all of the crude oil from our offshore operations is produced into FPSOs and “lifted” and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into FPSOs or onshore storage terminals. As a result, the timing of liftings may impact period-to-period results. In February 2014, we closed the sale of our Malaysia business. See Note 3, "Discontinued Operations," to our consolidated financial statements appearing earlier in this report for additional information regarding the sale.

Revenues during the second quarter and six-month period ended June 30, 2014 were significantly lower due to the sale of our Malaysia business in February 2014. Additionally, China production declined in the second quarter of 2014 compared to the same period of 2013 due to the temporary shut-in of production in Bohai Bay by the operator in May 2014 for scheduled repairs and maintenance activities. We expect that production will resume in September 2014. The following table reflects our production from discontinued operations and average realized commodity prices.

	Three Months Ended June 30,		Percentage Increase (Decrease)	Six Months Ended June 30,		Percentage Increase (Decrease)
	2014	2013		2014	2013	
Production/Liftings:[1]						
Crude oil and condensate (MBbls)	38	1,805	(98)%	1,024	4,354	(77)%
Natural gas (Bcf)	—	—	—%	—	0.2	(100)%
Total (MBOE)	38	1,805	(98)%	1,024	4,393	(77)%
Average Realized Prices:						
Crude oil and condensate (per Bbl)	$106.86	$104.28	2%	$109.36	$107.61	2%
Natural gas (per Mcf)	—	—	—%	—	3.76	(100)%

Crude oil equivalent (per BOE)	106.86	104.28	2 %	109.36	106.88	2 %

(1) Represents our net share of volumes sold regardless of when produced.

Operating Expenses. The following tables present information about our operating expenses for our discontinued operations.

	Unit-of-Production Three Months Ended June 30,		Percentage Increase (Decrease)	Total Amount Three Months Ended June 30,		Percentage Increase (Decrease)
	2014	2013		2014	2013	
	(Per BOE)			(In millions)		
Lease operating	$38.16	$18.78	103 %	$1	$34	(96)%
Production and other taxes	31.04	36.17	(14)%	1	65	(98)%
Depreciation, depletion and amortization	26.04	30.43	(14)%	1	55	(98)%
General and administrative	—	2.81	(100)%	—	5	(100)%
Total operating expenses	$95.24	$88.18	8 %	$3	$159	(98)%

	Unit-of-Production Six Months Ended June 30,		Percentage Increase (Decrease)	Total Amount Six Months Ended June 30,		Percentage Increase (Decrease)
	2014	2013		2014	2013	
	(Per BOE)			(In millions)		
Lease operating	$14.44	$15.76	(8)%	$15	$69	(79)%
Production and other taxes	28.77	38.24	(25)%	29	168	(82)%
Depreciation, depletion and amortization	36.24	29.50	23 %	37	130	(71)%
General and administrative	—	1.35	(100)%	—	6	(100)%
Total operating expenses	$79.45	$84.86	(6)%	$81	$373	(78)%

Our total operating expenses for discontinued operations for the three and six months ended June 30, 2014 decreased $156 and $292 million, respectively, compared to the same periods of 2013. These expenses declined primarily as a result of the sale of our Malaysia business in February 2014, combined with the temporary shut-in of Bohai Bay production in China for scheduled repairs and maintenance activities by the operator.

Liquidity and Capital Resources

The following discussion is inclusive of both our continuing and discontinued operations, unless otherwise noted.

We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this through drilling programs and property acquisitions, which require substantial capital expenditures. Lower prices for oil, natural gas and NGLs may reduce the amount of oil and gas that we can economically produce and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as further described below.

We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, as well as the available borrowing capacity of our revolving credit facility. Our 2014 budget is being financed through our cash flows from operations, proceeds from our first quarter 2014 Malaysia sale and the use of our credit facility. Approximately 85% of our expected 2014 domestic oil and gas production (excluding NGLs) supporting our estimated 2014 capital budget is protected from price volatility through the use of derivative contracts. Our 2014 capital budget for our continuing operations, excluding estimated capitalized interest and overhead of approximately $185 million, is expected to be approximately $1.7 billion and focuses on liquids-rich projects with higher returns. During 2014, we intend to invest approximately $150 million in China, a portion of which we expect to recover through insurance related to the August 2013 LF-7 topside installation incident.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results; oil, natural gas and NGL prices; industry conditions; the prices and availability of goods and services; and the extent to which properties are acquired or non-strategic assets sold. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

We continuously monitor our liquidity needs, coordinate our capital expenditure program with our expected cash flows and projected debt-repayment schedule, and evaluate our available funding alternatives in light of current and expected economic conditions. We believe that our liquidity position and ability to generate cash flows from our asset portfolio will be adequate to fund 2014 operations and continue to meet our other obligations.

On July 29, 2014, we entered into an agreement to sell our Granite Wash assets for approximately $588 million, subject to customary purchase price adjustments. See Note 15, "Subsequent Events," for additional information regarding the sale. We intend to use the proceeds from the Granite Wash sale to call and retire our $600 million aggregate principal of 7 % Senior Subordinated Notes due 2018.

Credit Arrangements. We maintain a revolving credit facility of $1.4 billion that matures in June 2018, as well as money market lines of credit of $195 million. We have no scheduled maturities of senior notes or senior subordinated notes until 2018. For a more detailed description of the terms of our credit arrangements and senior and senior subordinated notes, please see Note 9, “Debt,” to our consolidated financial statements appearing earlier in this report.

As of July 28, 2014, we had outstanding borrowings of $120 million and available borrowing capacity of approximately $1.3 billion under our revolving credit facility. We did not have any outstanding borrowings under our money market lines of credit, which have available borrowing capacity of approximately $195 million.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. We anticipate that our 2014 capital investment levels will exceed our estimate of cash flows from operations. As a result, we used proceeds from our recent Malaysia sale to fund the shortfall in the first quarter as well as to restore the available capacity of our credit arrangements, which we are using to fund the expected remaining shortfall.

At June 30, 2014, we had negative working capital of $601 million compared to negative working capital of $389 million at December 31, 2013. The changes in our working capital are primarily a result of the sale of our Malaysia business in February 2014 and the associated positive working capital attributable to the Malaysia business. The remaining change is due to the timing of the collection of receivables; changes in the fair value of our derivative positions; the timing of crude oil liftings in our international operations; drilling activities; payments made by us to vendors and other operators; and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Our primary source of capital and liquidity is cash flows from operations and are primarily affected by the sale of our oil, natural gas and NGLs, as well as commodity prices, net of the effects of derivative contract settlements and changes in working capital.

Our net cash flows from operations were $733 million (includes $63 million of cash flows from discontinued operations) for the six months ended June 30, 2014, an increase of $123 million compared to net cash flows from operations of $610 million (includes $138 million of cash flows from discontinued operations) for the same period in 2013 primarily due to changes in working capital and increased cash inflow due to higher revenues.

Cash Flows from Investing Activities. Net cash used in investing activities for the six months ended June 30, 2014 was $176 million compared to $873 million for the same period in 2013. The change is due to proceeds from the 2014 sale of our Malaysia business and from redemption of investments partially offset by increased capital expenditures in 2014 compared to 2013.

Cash Flows from Financing Activities. Net cash used in financing activities for the six months ended June 30, 2014 was $616 million compared to net cash provided by financing activities of $226 million for the same period in 2013. During the six months ended June 30, 2014, we reduced our outstanding borrowings under our revolving credit facility by $618 million using the proceeds received from the sale of Malaysia.

Capital Expenditures. Our capital investments for the first six months of 2014 increased 9% as compared to the same period of 2013. These amounts exclude non-cash asset retirement obligations, and capitalized interest and capitalized direct internal costs.

	Six Months Ended June 30,	
	2014	2013
	(In millions)	
Exploitation and development	$687	$584
Exploration (exclusive of exploitation and leasehold)	125	91
Acquisitions	15	4
Leasing proved and unproved property (leasehold)	46	10
Pipeline spending	4	10
Plug and abandonment settlements	3	6
Discontinued operations	73	170
Total	$953	$875

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a “working interest” basis. The joint operating agreement provides remedies to the operator if a non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. For further information, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Contractual Obligations" in our Quarterly Report on Form 10-Q for the three months ended March 31, 2014. There were no significant changes to these disclosures during the second quarter of 2014.

Oil and Gas Derivatives

We use derivative contracts to manage the variability in cash flows caused by commodity price fluctuations associated with our anticipated future oil and gas production for the next 24 to 36 months. As of June 30, 2014, we had no outstanding derivative contracts related to our NGL production or production associated with our discontinued operations. In addition, we may use basis contracts to manage volatilities in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes.

See the discussion and tables in Note 5, “Derivative Financial Instruments,” and Note 8, “Fair Value Measurements,” to our consolidated financial statements appearing earlier in this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open positions and the estimated fair market value of those positions as of June 30, 2014.

Between July 1, 2014 and July 28, 2014, we entered into additional derivative contracts as set forth below.

Crude Oil

Period and Type of Instrument	Volume in MBbls	NYMEX Contract Price Per Bbl		
			Collars	
		Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)
2015:				
Collars with sold puts	365	$ 75.00	$ 90.00	$ 104.50
2016:				
Collars with sold puts	1,279	75.00	90.00	97.29
2017:				
Collars with sold puts[(1)]	1,267	75.00	90.00	96.01

(1) Our collars with sold puts for 2017 are through June 2017.

Accounting for Derivative Activities. We do not designate future price-risk management activities as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience non-cash volatility in our reported earnings during periods of commodity price volatility. As of June 30, 2014, we had net derivative liabilities of $220 million, of which 42%, based on total contracted volumes, was measured based upon our valuation model (i.e. Black-Scholes) and, as such, were classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including the following:

- quoted forward prices for commodities;
- time value;
- volatility factors;
- counterparty credit risk; and
- current market and contractual prices for the underlying instruments.

As a result, the value of these contracts at their respective settlement dates could be significantly different than their fair value as of June 30, 2014. We use credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. See "— Critical Accounting Policies and Estimates — Commodity Derivative Activities" in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2013 and Note 5, "Derivative Financial Instruments," and Note 8, "Fair Value Measurements," to our consolidated financial statements appearing earlier in this report for additional discussion of the accounting applicable to our oil and gas derivative contracts.

New Accounting Requirements

In June 2014, the FASB issued guidance regarding stock-based compensation awards with targets that affect vesting and that could be achieved after the requisite service period. The guidance applies on a prospective basis to awards that are granted or modified on or after the effective date. The guidance is effective for annual periods beginning after December 15, 2015, and interim periods within those annual periods. We do not expect adoption of this guidance to have a material impact on our financial position or results of operations.

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings. The guidance is effective for interim and annual periods beginning on or after December 15, 2016. We are currently evaluating the impact of this guidance on our financial statements.

In April 2014, the FASB issued guidance regarding the reporting of discontinued operations. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. The guidance is effective for interim and annual periods beginning on or after December 15, 2014. We do not expect adoption of this guidance to have a material impact on our financial position or results of operations.

Forward-Looking Information

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). All statements, other than statements of historical facts included in this report, are forward-looking, including information relating to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures and other plans and objectives for future operations. Forward-looking statements are typically identified by use of terms such as “may,” “believe,” “expect,” “anticipate,” “intend,” “estimate,” “proje
“target,” “goal,” “plan,” “should,” “will,” “predict,” “potential” and similar expressions that convey the uncertainty of future e
or outcomes. Although we believe that these expectations are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

- oil, natural gas and NGL prices and demand;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing and climate change;
- land, legal and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- the availability and volatility of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, derivative contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the prices and quantities of commodities reflected in our commodity derivative arrangements as compared to the actual prices or quantities of commodities we produce or use;
- the volatility and liquidity in the commodity futures and commodity and financial derivatives markets;
- the availability of storage, transportation and refining capacity for the crude oil we produce in the Uinta Basin;
- drilling risks and results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- labor conditions;
- weather conditions;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- competitive conditions;
- terrorism or civil or political unrest in a region or country;
- our ability to monetize non-strategic assets, pay debt and the impact of changes in our investment ratings;
- electronic, cyber or physical security breaches;

- changes in tax rates;
- inflation rates;
- financial counterparty risk;
- uncertainties and changes in estimates of reserves;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities; and
- the additional factors discussed elsewhere in our public filings and press releases, including the factors discussed in "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" included in our 2013 Annual Report on Form 10-K.

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business and in this report.

Barrel or Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular derivative transaction.

Bcf. Billion cubic feet.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate or 42 gallons for NGLs.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploitation well. An exploration well drilled to find and produce probable reserves. Exploitation wells typically have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. An exploration well is a well drilled to find a new field or new reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

Liquids. Crude oil and NGLs.

Liquids-rich. Formations that contain crude oil or NGLs instead of, or as well as, natural gas.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

NGL. Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil (WTI) or natural gas (NYMEX) for the prior 12 months, adjusted for market differentials. The SEC provides a complete definition of prices in “Modernization of Oil and Gas Reporting” (Final Rule).

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production and requires the owner to pay a share of the costs of drilling and production operations.

WTI. West Texas Intermediate, a grade of crude oil.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in oil, natural gas and NGL prices, interest rates and foreign currency exchange rates as discussed below.

Oil, Natural Gas and NGL Prices

Our decision on the quantity and price at which we choose to enter into derivative contracts is based in part on our view of current and future market conditions. While the use of derivative contracts limits the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements. In addition, the use of derivative contracts may involve basis risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative contracts also involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At June 30, 2014, 10 of our 16 counterparties accounted for approximately 85% of our contracted volumes with no single counterparty accounting for more than 15%. For a further discussion of our derivative activities, see the information under the caption “Oil and Gas Derivatives” in Item 2 appearing earlier in this report and the discussion and tables in Note 5, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report. For a further discussion of the types of derivative positions, refer to Note 5, "Derivative Financial Instruments" within Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2013.

Interest Rates

We consider our interest rate exposure to be minimal because 99% of our obligations were at fixed rates as of June 30, 2014, and our variable rate debt was at interest rates of 2% or less. A 10% increase in LIBOR would not impact our interest cost on debt outstanding as of June 30, 2014, but would affect the fair value of our outstanding debt, as well as interest costs associated with future debt issuances or borrowings under our revolving credit facility.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country’s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts related to foreign currencies at June 30, 2014.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2014.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and our Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the second quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based upon that evaluation, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. Legal Proceedings

In February 2013, after a voluntary internal audit, we self-disclosed to the Environmental Protection Agency (EPA) our inadvertent failure to test certain stationary engines located in Utah. The engines were installed as a result of Newfield's own effort to replace higher emitting engines with lower emitting engines. The engines, however, were subject to certain air quality performance standards under 40 C.F.R. Part 60, Subpart JJJJ and required us to conduct certain emission performance tests within a defined time period. We inadvertently did not conduct the requisite tests and have been negotiating with the EPA to remedy the situation and to create a particular testing protocol to get these facilities compliant with the regulations. We have not received a Notice of Violation (NOV) but anticipate entering into a settlement with the EPA on this matter. The violations did not contain any allegations of environmental spills, releases or pollution above permitted levels. We do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (a) claims from royalty owners for disputed royalty payments,

(b) commercial disputes, (c) personal injury claims and (d) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations. In addition, from time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate related to alleged violations of environmental statutes or rules and regulations promulgated thereunder. We cannot predict with certainty whether these notices of violation will result in fines or penalties, or if such fines or penalties are imposed, that they would exceed individually or in the aggregate $100,000. If any fines or penalties are in fact imposed that are greater than $100,000, then we will disclose such fact in our subsequent filings.

Item 1A. Risk Factors

The following risk factors update, and should be considered in addition to, the risk factors previously reported in our Annual Report on Form 10-K for the year ended December 31, 2013. Other than the risk factors discussed below, there have been no material changes with respect to the risk factors previously reported in our Annual Report on Form 10-K.

We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business. Existing and potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil, gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include the following, in addition to the other matters discussed under the caption "Regulation" in Items 1 and 2 of this report:

•the amounts and types of substances and materials that may be released into the environment;

•response to unexpected releases into the environment;

•reports and permits concerning exploration, drilling, production and other operations;

•the placement and spacing of wells;

•unitization and pooling of properties;

•calculating royalties on oil and gas produced under federal and state leases; and

•taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource risk mitigation, damages and other environmental damages. We also could be required to install expensive pollution control measures, engage in environmental risk management and hedging activities or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. In addition, failure to comply with applicable laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

Further, changes to existing environmental regulations or the adoption of new regulations may unfavorably impact us, the oil and gas industry generally, our suppliers or our customers. For example, governments around the world have become increasingly focused on regulating greenhouse gas (GHG) emissions and addressing the impacts of climate change in some manner. In the absence of dedicated federal legislation on climate change mitigation or adaptation, the U.S. Environmental Protection Agency (EPA) has promulgated several rulemakings to regulate, measure or monitor GHG emissions under the existing provisions of the Clean Air Act, or CAA. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, as well as from certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis. The new regulations could impact certain facilities in which we have interests (legal, equitable, operated or non-operated) by increasing regulatory risks and reporting requirements.

In December 2009, the EPA issued an "endangerment finding" under the CAA concluding that the current and projected concentrations of GHGs in the atmosphere from motor vehicles threaten the public health and welfare of current and future generations. The finding, once made, required the EPA to begin regulating GHG emissions from new cars and light trucks under the CAA. Indirectly, the EPA argued that it also triggered an EPA obligation to regulate GHG emissions under existing relevant air permitting programs for large stationary sources. On January 2, 2011, the EPA initiated Prevention of Significant Deterioration (PSD) permitting requirements for carbon dioxide and other GHGs from large and modified stationary sources. Permits limiting GHGs have been issued for a variety of new or modified facilities under the Clean Air Act PSD program. GHG emissions also trigger Title V operating permit requirements for new and existing sources that exceed certain established emission thresholds. Emission levels in excess of these thresholds can then trigger preconstruction permit requirements and application of best available control technology (BACT) as determined on a source-by-source basis.

In June 2014, the Supreme Court upheld most of the EPA's GHG permitting requirements, allowing the agency to regulate the emission of GHGs from stationary sources already subject to the Clean Air Act's prevention of significant deterioration (PSD) and Title V requirements. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the Supreme Court's ruling, also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture GHGs.

The EPA took additional action under the Clean Air Act in June 2014. In accordance with President Obama's Climate Action Plan, on June 18, 2014, the EPA proposed rules to reduce carbon emissions from electric generating units. The proposal, commonly called the "Clean Power Plan," requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units, commencing in 2020, with the reductions to be fully phased in by 2030. Each state is given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 30% from 2005 levels. As proposed, states are given great flexibility in meeting their emission reduction targets, and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units, renewable or end-use energy efficiency. It is not possible at this time to predict what requirements might be adopted by the EPA in the final rule, expected in 2015, or how any such final rule would impact our business.

If the U.S. Congress adopts market-based tax, energy or other mechanisms to regulate the carbon intensity of natural resources, or promote or require the reduction of GHG emissions from certain industrial sectors, such legislation, depending on design and scope, could increase the cost of oil and gas production and market demand. Some states, like California, have implemented state-wide GHG mitigation programs to reduce GHG emissions through a mixture of regulatory programs, including a low carbon fuel standard and cap-and-trade market applicable to, among others, electric utilities and transportation fuels.

Further, the U.S. Congress has previously proposed legislation that would directly impact our industry. In response to the 2010 Macondo incident in the Gulf of Mexico, the U.S. Congress considered a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations governing our operations in the United States, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

These and other potential regulations, if introduced and passed in Congress, could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows. See also "- The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells."

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic-fracturing techniques on almost all of our U.S. onshore oil and natural gas properties. Hydraulic fracturing involves using water, sand or other proppant materials, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the BLM and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Certain municipalities have already banned hydraulic fracturing, and courts have upheld those moratoria in some instances.

For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process, and the RCT adopted rules regarding the same in December 2011. On September 11, 2012, the RCT approved new regulations relating to the commercial recycling of produced water and/or hydraulic-fracturing flowback fluid, and on December 17, 2012, proposed revised amendments to rules of casing, cementing, well control and completion of oil and gas wells.

In the past several years, dozens of states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. For example, on June 30, 2014, New York's highest state court upheld local zoning ordinances that ban hydraulic fracturing within municipal limits.

In the event state, local or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, on July 3, 2014, major university and U.S. Geological Survey researchers published a study purporting to find a causal connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

The EPA is also developing a proposed rule to amend the Effluent Limitations Guidelines for the Oil and Gas Extraction Category. The proposed rule is scheduled for publication in 2014. It is unclear what the proposed rule will require, but with potential future limits on deep well injection, these limits may become increasingly important, as extraction and production companies look to dispose of wastewater to publicly-owned treatment works or centralized waste treaters. If deep well injection is shut down or limited, and discharge to surface waters is impossible, we may face increased disposal costs.

In recent years, the federal government has increased its focus on the environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality has coordinated an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices involving the use of diesel fuel.

The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuels under the Safe Drinking Water Act and in February 2014 issued permitting guidance for hydraulic fracturing activities using diesel.

Further, on May 19, 2014, the EPA published an Advance Notice of Proposed Rulemaking (ANPR) under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties.

In addition, in May 2013, the Bureau of Land Management issued a proposed rule that would require the public disclosure of chemicals used in hydraulic fracturing operations, set requirements for well-bore integrity and establish flowback water standards for all hydraulic fracturing operations on federal public lands and American Indian Tribal lands. The proposed rule also required that an operator certify, in writing, that (a) the stimulation design complies with all federal, state, tribal and local regulations; (b) the stimulation was completed in accordance with the design approved by BLM and all applicable regulations; and (c) the well-bore integrity was maintained during the fracturing process and flowback water was properly stored, treated and disposed. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with draft results to be issued in 2014 for public comment and peer review.

In addition, the U.S. Department of Energy has conducted an investigation into practices to better protect the environment from drilling using hydraulic fracturing completion methods. In a November 18, 2011 report, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued 20 recommendations to federal agencies, states and private entities that are intended to reduce the environmental impact and assure the safety of shale gas production. The U.S. Department of Energy continues to work with other federal agencies to identify best practices for shale gas production. Some of these may become enforceable statutory or regulatory requirements that would likely increase our compliance costs.

Given the heightened awareness regarding the use of hydraulic fracturing, it is possible that regulatory agencies or private parties may suggest that hydraulic fracturing has caused groundwater contamination, whether or not such allegations are accurate. For example, on December 8, 2011, the EPA released a preliminary report indicating that hydraulic fracturing is responsible for groundwater contamination in Pavillion, Wyoming, although the EPA's draft report has been hotly criticized as ignoring certain facts and utilizing incorrect data. In addition, the EPA has alleged in an enforcement action against an operator in Texas that the operator contaminated local groundwater wells, although the RCT found after an evidentiary hearing that the operator was not responsible for the contamination. However, in 2013 the EPA deferred the Pavillion matter to state oversight and withdrew the emergency action order in Texas. Nevertheless, energy extraction, with a focus on onshore natural gas production, remains an EPA enforcement initiative. Thus, regulatory agencies or private parties alleging groundwater contamination linked to hydraulic fracturing could trigger defense costs in administrative or civil litigation or proceedings to rebut the allegations.

Additionally, certain members of the Congress have called upon (a) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (b) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and (c) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Further, on August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA finalized rules under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA regulations include NSPS standards for completions of hydraulically-fractured gas wells.

Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions. After January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured.

Further, the regulations under NESHAPS include specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. We are currently evaluating the effect these regulations could have on our business. Compliance with such regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

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

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended June 30, 2014.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased under the Plans or Programs
April 1 — April 30, 2014	6,262	$31.26	—	—
May 1 — May 31, 2014	14,055	33.95	—	—
June 1 — June 30, 2014	10,696	36.40	—	—
Total	31,013	$34.25	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards and restricted stock units. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

39

Item 6. Exhibits

Exhibit Number	Description
3.1	Third Restated Certificate of Incorporation of Newfield Exploration Company dated December 14, 2011 (incorporated by reference to Exhibit 3.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 1-12534))
3.2	Amended and Restated Bylaws of Newfield (incorporated by reference to Exhibit 3.2 to Newfield's Current Report on Form 8-K filed with the SEC on July 25, 2013 (File No. 1-12534))
*31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

* Filed or furnished herewith.

SIGNATURE

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

NEWFIELD EXPLORATION COMPANY

Date: July 30, 2014

By: /s/ LAWRENCE S. MASSARO
Lawrence S. Massaro
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit Index

Exhibit Number	Description
3.1	Third Restated Certificate of Incorporation of Newfield Exploration Company dated December 14, 2011 (incorporated by reference to Exhibit 3.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 1-12534))
3.2	Amended and Restated Bylaws of Newfield (incorporated by reference to Exhibit 3.2 to Newfield's Current Report on Form 8-K filed with the SEC on July 25, 2013 (File No. 1-12534))
*31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

* Filed or furnished herewith.