NEWFIELD EXPLORATION CO /DE/
Form 10-Q
August 03, 2016

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, 2016
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, 2016, there were 198,604,244 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, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$165	$5
Accounts receivable, net	256	262
Inventories	19	34
Derivative assets	150	284
Other current assets	48	40
Total current assets	638	625
Oil and gas properties, net — full cost method ($1,386 and $780 were excluded from amortization at June 30, 2016 and December 31, 2015, respectively)	3,403	3,819
Other property and equipment, net	170	172
Derivative assets	20	105
Long-term investments	21	20
Other assets	33	27
Total assets	$4,285	$4,768
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$59	$41
Accrued liabilities	441	533
Advances from joint owners	77	58
Asset retirement obligations	2	2
Derivative liabilities	78	13
Total current liabilities	657	647
Other liabilities	72	48
Derivative liabilities	21	9
Long-term debt	2,430	2,467
Asset retirement obligations	204	192
Deferred taxes	29	26
Total long-term liabilities	2,756	2,742
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
Common stock ($0.01 par value, 300,000,000 shares authorized at June 30, 2016 and December 31, 2015; 199,529,109 and 164,102,786 shares issued at June 30, 2016 and December 31, 2015, respectively)	2	2
Additional paid-in capital	3,231	2,436
Treasury stock (at cost, 936,218 and 612,469 shares at June 30, 2016 and December 31, 2015, respectively)	(33)	(22)
Accumulated other comprehensive gain (loss)	(2)	(2)
Retained earnings (deficit)	(2,326)	(1,035)
Total stockholders' equity	872	1,379

Total liabilities and stockholders' equity	$4,285	$ 4,768

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

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Oil, gas and NGL revenues	$381	$469	$665	$818
Operating expenses:				
Lease operating	62	73	123	148
Transportation and processing	66	52	129	101
Production and other taxes	11	17	21	30
Depreciation, depletion and amortization	160	248	337	485
General and administrative	58	51	102	114
Ceiling test and other impairments	522	1,521	1,028	2,313
Other	—	3	1	7
Total operating expenses	879	1,965	1,741	3,198
Income (loss) from operations	(498)	(1,496)	(1,076)	(2,380)
Other income (expense):				
Interest expense	(38)	(46)	(79)	(90)
Capitalized interest	11	8	20	15
Commodity derivative income (expense)	(133)	(10)	(150)	143
Other, net	—	(22)	1	(14)
Total other income (expense)	(160)	(70)	(208)	54
Income (loss) before income taxes	(658)	(1,566)	(1,284)	(2,326)
Income tax provision (benefit):				
Current	6	15	4	18
Deferred	3	(589)	3	(872)
Total income tax provision (benefit)	9	(574)	7	(854)
Net income (loss)	$(667)	$(992)	$(1,291)	$(1,472)
Earnings (loss) per share:				
Basic	$(3.36)	$(6.09)	$(6.87)	$(9.55)
Diluted	$(3.36)	$(6.09)	$(6.87)	$(9.55)
Weighted-average number of shares outstanding for basic earnings (loss) per share	198	163	188	154
Weighted-average number of shares outstanding for diluted earnings (loss) per share	198	163	188	154

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,	
	2016	2015	2016	2015
Net income (loss)	$(667)	$(992)	$(1,291)	$(1,472)
Other comprehensive income (loss):				
Unrealized gain (loss) on investments, net of tax	—	—	—	—
Other comprehensive income (loss), net of tax	—	—	—	—
Comprehensive income (loss)	$(667)	$(992)	$(1,291)	$(1,472)

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, 2016	2015
Cash flows from operating activities:		
Net income (loss)	$(1,291)	$(1,472)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	337	485
Deferred tax provision (benefit)	3	(872)
Stock-based compensation	19	25
Unrealized (gain) loss on derivative contracts	296	101
Ceiling test and other impairments	1,028	2,313
Other, net	6	22
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(1)	(25)
(Increase) decrease in inventories	4	1
(Increase) decrease in other current assets	(8)	5
(Increase) decrease in other assets	(7)	(3)
Increase (decrease) in accounts payable and accrued liabilities	(41)	(8)
Increase (decrease) in advances from joint owners	19	9
Increase (decrease) in other liabilities	14	(4)
Net cash provided by (used in) operating activities	378	577
Cash flows from investing activities:		
Additions to oil and gas properties	(471)	(916)
Acquisitions of oil and gas properties	(495)	(1)
Proceeds from sales of oil and gas properties	29	29
Additions to other property and equipment	(8)	(10)
Net cash provided by (used in) investing activities	(945)	(898)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	536	916
Repayments of borrowings under credit arrangements	(575)	(1,362)
Proceeds from issuance of senior notes	—	691
Repayment of senior subordinated notes	—	(700)
Debt issue costs	—	(8)
Proceeds from issuances of common stock, net	777	817
Purchases of treasury stock, net	(11)	(4)
Other	—	(1)
Net cash provided by (used in) financing activities	727	349
Increase (decrease) in cash and cash equivalents	160	28
Cash and cash equivalents, beginning of period	5	14
Cash and cash equivalents, end of period	$165	$42

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

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

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Gain (Loss)	Total Stockholders' Equity
Balance, December 31, 2015	164.1	$ 2	(0.6)	$ (22)	$ 2,436	$ (1,035)	$ (2)	$ 1,379
Issuances of common stock	35.4	—			777			777
Stock-based compensation					18			18
Treasury stock, net			(0.3)	(11)	—			(11)
Net income (loss)						(1,291)		(1,291)
Balance, June 30, 2016	199.5	$ 2	(0.9)	$ (33)	$ 3,231	$ (2,326)	$ (2)	$ 872

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 operations are focused primarily on large scale, onshore liquids-rich resource plays in the United States. Our principal areas of operation are the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota, the Uinta Basin of Utah and the Maverick and Gulf Coast basins of Texas. In addition, we have oil developments offshore China.

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 (US GAAP). 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, 2015.

Risks and Uncertainties

As an independent oil and natural gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil, natural gas and NGLs. Historically, the energy markets have been very volatile, and there can be no assurance that commodity prices will not be subject to wide fluctuations in the future. A substantial or extended decline in commodity prices could have a material adverse effect on our financial position, results of operations, cash flows, access to capital and on the quantities of oil, natural gas and NGL reserves that we can economically produce. Other risks and uncertainties that could affect us in the current commodity price environment include, but are not limited to, counterparty credit risk for our receivables, responsibility for decommissioning liabilities for offshore interests we no longer own, access to credit markets, regulatory risks and ability to meet financial ratios and covenants in our financing agreements.

Use of Estimates

The preparation of financial statements in accordance with US GAAP 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, the timing and amount of transfers of our unevaluated properties into our amortizable full cost pool, the recoverability of our deferred tax assets and the fair value of our derivative contracts.

Restructuring Costs

Restructuring costs include severance and related benefit costs, costs associated with abandoned office space, employee relocation costs and other associated costs. Employee severance and related benefit costs are recognized on a straight-line basis over the required service period, if any. Employee relocation costs are expensed as incurred. On the date a leased property ceases to be used, a liability for non-cancellable office-lease costs associated with restructuring is recognized and measured at fair value on our consolidated balance sheet. Fair value estimates include assumptions regarding estimated future sublease payments. These estimates could materially differ from actual results and may require revision to initial estimates of the liability. See Note 15, "Restructuring Costs," for additional disclosures.

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

We have restricted cash of $20 million included in "Other assets" on our consolidated balance sheet at June 30, 2016, as compared to $13 million at December 31, 2015, which represent amounts held in escrow accounts to satisfy future plug and abandonment obligations for our China operations. These amounts are restricted as to their current use and will be released as we plug and abandon wells and facilities in China. Consistent with our other plug and abandonment activities, changes in restricted cash are included in cash flows from operating activities in our consolidated statement of cash flows.

New Accounting Requirements

In March 2016, the Financial Accounting Standards Board (FASB) issued guidance regarding the simplification of employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We adopted this guidance in the second quarter of 2016 as permitted by the guidance. Adoption of this guidance did not impact our financial statements, except for the simplification in accounting for income taxes using a modified retrospective approach. Recognition of previously unrecognized excess tax benefits related to stock-based compensation created a deferred tax asset of $37 million. As we consider it more likely than not that the deferred tax asset will not be realized, we recorded a full valuation allowance of $37 million. We elected to continue our current policy of estimating forfeitures.

In February 2016, the FASB issued guidance regarding the accounting for leases. The guidance requires recognition of most leases on the balance sheet. The guidance requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The guidance is effective for interim and annual periods beginning after December 15, 2018. We are currently evaluating the impact of this guidance on our financial statements.

In January 2016, the FASB issued guidance regarding several broad topics related to the recognition and measurement of financial assets and liabilities. The guidance is effective for interim and annual periods beginning after December 15, 2017. We are currently evaluating the impact of this guidance on our financial statements.

In August 2014, the FASB issued guidance regarding disclosures of uncertainties about an entity's ability to continue as a going concern. The guidance applies prospectively to all entities, requiring management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern and disclose certain information when substantial doubt exists. We will adopt this guidance for the annual period ending December 31, 2016.

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. In April and May 2016, the FASB issued additional guidance, addressed implementation issues and provided technical corrections. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings (deficit). The guidance is effective for interim and annual periods beginning on or after December 15, 2017. We are currently evaluating the impact of this guidance on our financial statements.

2. Accounts Receivable

Accounts receivable consisted of the following:

	June 30, 2016	December 31, 2015
	(In millions)	
Revenue	$133	$ 94
Joint interest	100	125
Other	39	59
Reserve for doubtful accounts	(16)	(16)
Total accounts receivable, net	$256	$ 262

3. Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and natural gas operations and oil produced but not sold in our China operations. At June 30, 2016 and December 31, 2015, the crude oil inventory from our China operations consisted of approximately 7,000 and 335,000 barrels of crude oil, respectively.

4. 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 may limit or partially reduce the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements.

In addition to the derivative strategies outlined in our Annual Report on Form 10-K for the year ended December 31, 2015, we also utilize swaptions from time to time. A swaption is an option to exercise a swap where the buyer (counterparty) of the swaption purchases the right from the seller (Newfield), but not the obligation, to enter into a fixed-price swap with the seller on a predetermined date (expiration date). The swap price is a fixed price determined at the time of the swaption contract. If the swaption is exercised, the contract will become a swap treated consistent with our other fixed-price swaps.

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 5, “Fair Value Measurements.”

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

At June 30, 2016, we had outstanding derivative positions as set forth in the tables below.

Crude Oil

Period and Type of Instrument	Volume in MBbls	NYMEX Contract Price Per Bbl: Swaps (Weighted Average)	Purchased Calls (Weighted Average)(2)	Sold Puts (Weighted Average)(1)	Collars: Floors (Weighted Average)	Collars: Ceilings (Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
2016:							
Fixed-price swaps	6,808	$41.84	$ —	$ —	$ —	$ —	$ (55)
Fixed-price swaps with sold puts:	4,600						
Fixed-price swaps		89.97	—	—	—	—	184
Sold puts		—	—	74.40	—	—	(113)
Collars with sold puts:	2,944						
Collars		—	—	—	90.00	95.98	118
Sold puts		—	—	75.00	—	—	(74)
Purchased calls	7,544	—	73.70	—	—	—	1
2017:							
Fixed-price swaps	6,205	45.43	—	—	—	—	(42)
Fixed-price swaps with sold puts:	4,468						
Fixed-price swaps		88.37	—	—	—	—	158
Sold puts		—	—	73.28	—	—	(99)
Collars with sold puts:	2,080						
Collars		—	—	—	90.00	95.59	79
Sold puts		—	—	75.00	—	—	(50)
Purchased calls	6,548	—	73.81	—	—	—	7
Total							$ 114

____

(1) For the volumes with sold puts, if the market prices remain below our sold puts at contract settlement, we will receive the market price plus the following:

- the difference between our floors and our sold puts for collars with sold puts; or
- the difference between our swaps and our sold puts for fixed-price swaps with sold puts.

We have effectively locked in the spreads noted above (less the deferred call premium) for a portion of the volumes with sold puts through the use of purchased calls.

(2) We deferred the premiums related to the purchased calls until contract settlement. At June 30, 2016, the deferred premiums totaled $19 million.

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

Natural Gas

Period and Type of Instrument	Volume in MMMBtus	NYMEX Contract Price Per MMBtu: Swaps (Weighted Average)	Sold Puts (Weighted Average)	Collars: Floors (Weighted Average)	Collars: Ceilings (Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
2016:						
Fixed-price swaps	36,800	$2.28	$ —	$ —	$ —	$ (26)
Collars	5,520	—	—	4.00	4.54	5
2017:						
Fixed-price swaps	27,375	2.73	—	—	—	(12)
Collars	29,200	—	—	2.64	2.93	(10)
2018:						
Collars	10,950	—	—	2.80	3.32	—
Total						$ (43)

Additional Disclosures about Derivative Financial 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: Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location: Current	Noncurrent	Derivative Liabilities: Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location: Current	Noncurrent
	(In millions)				(In millions)			
June 30, 2016								
Oil positions	$520	$ (355)	$145	$ 20	$(406)	$ 355	$(39)	$ (12)
Natural gas positions	5	—	5	—	(48)	—	(39)	(9)
Total	$525	$ (355)	$150	$ 20	$(454)	$ 355	$(78)	$ (21)
December 31, 2015								
Oil positions	$1,005	$ (638)	$262	$ 105	$(660)	$ 638	$(13)	$ (9)
Natural gas positions	22	—	22	—	—	—	—	—
Total	$1,027	$ (638)	$284	$ 105	$(660)	$ 638	$(13)	$ (9)

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, 2016	2015	Six Months Ended June 30, 2016	2015
	(In millions)			
Derivatives not designated as hedging instruments:				
Realized gain (loss) on oil positions	$58	$91	$129	$187

Realized gain (loss) on natural gas positions	6	32	17	57
Total realized gain (loss)	64	123	146	244
Unrealized gain (loss) on oil positions	(149)	(99)	(232)	(62)
Unrealized gain (loss) on natural gas positions	(48)	(34)	(64)	(39)
Total unrealized gain (loss)	(197)	(133)	(296)	(101)
Total	$(133)	$(10)	$(150)	$143

The use of derivative transactions 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, 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, 2016, 10 of our 16 counterparties accounted for approximately 85% of our contracted volumes, with the largest counterparty accounting for approximately 12%.

At June 30, 2016, approximately 85% of our volumes subject to derivative instruments are with lenders under our credit facility. Our credit facility, senior 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.

5. 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, purchased calls or swaptions) and other financial investments.

- Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) 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) was a Monte Carlo simulation that was 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.

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.

The determination of the fair values of our derivative contracts incorporates various factors, which 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), 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.

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

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, 2015:				
Money market fund investments	$2	$ —	$ —	$2
Deferred compensation plan assets	5	—	—	5
Equity securities available-for-sale	8	—	—	8
Oil and gas derivative swap contracts	—	675	—	675
Oil and gas derivative option contracts	—	—	(308)	(308)
Stock-based compensation liability awards	(12)	—	—	(12)
Total	$3	$ 675	$ (308)	$370
As of June 30, 2016:				
Money market fund investments	$158	$ —	$ —	$158
Deferred compensation plan assets	5	—	—	5
Equity securities available-for-sale	9	—	—	9
Oil and gas derivative swap contracts	—	206	—	206
Oil and gas derivative option and swaption contracts	—	—	(135)	(135)
Stock-based compensation liability awards	(22)	—	—	(22)
Total	$150	$ 206	$ (135)	$221

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.

	Derivatives	Stock-Based Compensation	Total
	(In millions)		
Balance at January 1, 2015	$(381)	$ (3)	$(384)
Realized or unrealized gains (losses) included in earnings	109	—	109
Purchases, issuances, sales and settlements:			
Settlements	104	—	104
Transfers into Level 3	—	—	—
Transfers out of Level 3	—	—	—
Balance at June 30, 2015	$(168)	$ (3)	$(171)
Change in unrealized gains or losses included in earnings relating to Level 3 instruments still held at June 30, 2015	$108	$ —	$108
Balance at January 1, 2016	$(308)	$ —	$(308)
Realized or unrealized gains (losses) included in earnings	(4)	—	(4)
Purchases, issuances, sales and settlements:			
Settlements	131	—	131
Transfers into Level 3	—	—	—
Transfers out of Level 3[(1)]	46	—	46
Balance at June 30, 2016	$(135)	$ —	$(135)
Change in unrealized gains or losses included in earnings relating to Level 3 instruments still held at June 30, 2016	$43	$ —	$43

(1) During the second quarter of 2016, we transferred $46 million of derivative option contracts out of the Level 3 hierarchy. The transfer was the result of our Level 3 swaptions being exercised by the counterparties as swaps in June 2016.

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 volatility factors and 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. 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. See Note 4, "Derivative Financial Instruments," for additional discussion of our derivative instruments.

Stock-Based Compensation. The calculation of the fair value of the SVAP liability required the use of a probability-based Monte Carlo simulation, which included unobservable inputs. The simulation predicted multiple scenarios of future stock returns over the performance period, which were discounted to calculate the fair value. The fair value was recognized over a service period derived from the simulation. The SVAP performance period and program ended December 31, 2015.

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

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	$ (131)	Black-Scholes	Oil price volatility	28.67% — 61.37%
			Credit risk	0.02 % — 1.92%
Natural gas option and swaption contracts	$ (4)	Black-Scholes	Natural gas price volatility	25.13% — 56.34%
			Credit risk	0.01 % — 2.79%

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, 2016	December 31, 2015
	(In millions)	
5¾% Senior Notes due 2022	$765	$ 668
5 % Senior Notes due 2024	1,000	831
5 % Senior Notes due 2026	679	542

Any amounts outstanding under our revolving credit facility and money market lines of credit as of the indicated dates are stated at cost, which approximates fair value. See Note 10, "Debt."

6. Oil and Gas Properties

Oil and gas properties consisted of the following:

	June 30, 2016	December 31, 2015
	(In millions)	
Proved	$21,889	$21,568
Unproved	1,386	780
Gross oil and gas properties	23,275	22,348
Accumulated depreciation, depletion and amortization	(9,363)	(9,048)
Accumulated impairment	(10,509)	(9,481)
Net oil and gas properties	$3,403	$3,819

Costs withheld from amortization as of June 30, 2016 consisted of the following:

	Costs Incurred In				
	2016	2015	2014	2013	Total
	(In millions)				

Acquisition costs	$516	$339	$165	$115	$1,135
Exploration costs	143	12	—	—	155
Capitalized interest	20	33	43	—	96
Total costs withheld from amortization (unproved)	$679	$384	$208	$115	$1,386

We capitalized approximately $30 million and $26 million of interest and direct internal costs during the three months ended June 30, 2016 and 2015, respectively, and $56 million and $58 million during the six months ended June 30, 2016 and 2015, respectively.

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

At June 30, 2016, the ceiling value of our reserves was calculated based upon SEC pricing of $43.14 per barrel for oil and $2.24 per MMBtu for natural gas, adjusted for market differentials. Using these prices, our ceiling for the U.S. did not exceed the net capitalized costs of oil and gas properties resulting in a ceiling test impairment. Our U.S. ceiling test impairment was approximately $501 million ($501 million after tax due to a full valuation allowance on related deferred tax assets) for the three months ended June 30, 2016. For the six months ended June 30, 2016, we recorded U.S. ceiling test impairments of approximately $962 million ($962 million after tax due to a full valuation allowance on related deferred tax assets).

Using SEC pricing, our ceiling for China at June 30, 2016 did not exceed the net capitalized costs of oil and gas properties, resulting in a ceiling test impairment for the three months ended June 30, 2016 of approximately $21 million ($21 million after tax due to a full valuation allowance on related deferred tax assets). For the six months ended June 30, 2016, we recorded China ceiling test impairments of approximately $66 million ($66 million after tax due to a full valuation allowance on related deferred tax assets).

Further declines in SEC pricing or downward revisions to our estimated proved reserves could result in additional ceiling test impairments of our oil and gas properties in subsequent periods.

Anadarko Basin Acquisition

On June 30, 2016, we acquired additional properties in the Anadarko Basin STACK play for an adjusted cash purchase price of $490 million. The purchase price is subject to customary post-close adjustments and is pending the outcome of pre-acquisition contingencies associated with title matters. We also assumed asset retirement obligations of $8 million. At June 30, 2016, approximately $460 million was allocated to unproved properties and wells in progress and $38 million was allocated to proved oil and gas properties.

7. Other Property and Equipment

Other property and equipment consisted of the following:

	June 30, 2016	December 31, 2015
	(In millions)	
Furniture, fixtures and equipment	$158	$ 152
Gathering systems and equipment	115	115
Accumulated depreciation and amortization	(103)	(95)
Net other property and equipment	$170	$ 172

8. Income Taxes

The following table presents a reconciliation of the United States statutory income tax rate to our effective income tax rate.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
U.S. statutory income tax rate	35.0 %	35.0 %	35.0 %	35.0 %
State and local income taxes, net of federal effect	0.7	2.1	0.7	2.1
Valuation allowance, domestic	(37.0)	—	(35.7)	—

Valuation allowance, international	(1.5)	—	(2.2)	—
Foreign tax on foreign earnings	—	(0.6)	1.1	(0.5)
Other	1.4	0.2	0.5	0.1
Effective income tax rate	(1.4)%	36.7 %	(0.6)%	36.7 %

Due to the ceiling test impairments of our oil and gas properties in 2015, we moved from a deferred tax liability position to a deferred tax asset position in various taxing jurisdictions. With the continuation of current commodity price levels, we consider it more likely than not that the related tax benefits will not be realized and therefore, we have a valuation allowance on

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

our domestic and China deferred tax assets. These valuation allowances recorded in 2016 significantly reduced our effective income tax rate for the three and six months ended June 30, 2016.

As of June 30, 2016, we did not have a liability for uncertain tax positions, and as such, we did not accrue related interest or penalties. The tax years 2011 through 2015 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

9. Accrued Liabilities

Accrued liabilities consisted of the following:

	June 30, 2016	December 31, 2015
	(In millions)	
Revenue payable	$164	$ 164
Accrued capital costs	93	128
Accrued lease operating expenses	30	48
Employee incentive expense	31	53
Accrued interest on debt	65	66
Taxes payable	15	25
Other	43	49
Total accrued liabilities	$441	$ 533

10. Debt

Our debt consisted of the following:

	June 30, 2016	December 31, 2015
	(In millions)	
Senior unsecured debt:		
Revolving credit facility — LIBOR based loans (matures in June 2020)	$—	$ —
Money market lines of credit(1)	—	39
Total credit arrangements	—	39
5¾% Senior Notes due 2022	750	750
5 % Senior Notes due 2024	1,000	1,000
5 % Senior Notes due 2026	700	700
Total senior unsecured debt	2,450	2,489
Debt issuance costs	(20)	(22)
Total long-term debt	$2,430	$ 2,467

(1) Because we have the ability and intent to use our available credit facility capacity 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 debt.

Credit Arrangements

In March 2016, we entered into the fifth amendment to our Credit Agreement. This amendment changed certain definitions related to our financial covenants and decreased our interest rate coverage ratio from 3.0:1.0 to 2.5:1.0. Our borrowing capacity remains at $1.8 billion and the facility maturity date remains June 2020. We incurred approximately $3 million of financing costs related to this amendment, which were included in "Interest expense" on our consolidated statement of operations. As of June 30, 2016, the largest individual loan commitment by any lender was 12% of total commitments.

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

During the first quarter of 2016, our debt rating was downgraded by rating agencies, and as a result, our borrowing costs under the credit facility increased by 50 basis points. In addition, our available borrowing capacity (before any amounts drawn) under our money market lines of credit with various institutions, the availability of which is at the discretion of those financial institutions, was reduced from $195 million at December 31, 2015 to $160 million at March 31, 2016. Our available borrowing capacity related to our money market lines of credit was further reduced to $135 million during the second quarter of 2016. This borrowing capacity is subject to compliance with restrictive covenants in our credit facility.

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 (125 basis points per annum at June 30, 2016) or (b) the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (225 basis points per annum at June 30, 2016).

Under our credit facility, we pay commitment fees on available but undrawn amounts based on a grid of our debt rating (42.5 basis points per annum at June 30, 2016). We incurred aggregate commitment fees under our credit facility of approximately $2 million and $4 million for the three and six-month periods ended June 30, 2016, respectively, which were recorded in “Interest expense” on our consolidated statement of operations. For the three and six months ended June 30, 2015,
we incurred commitment fees under our 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 the 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 and ceiling test impairments) to interest expense of at least 2.5 to 1.0. At June 30, 2016, we were in compliance with all of our debt covenants.

As of June 30, 2016, 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 (225 basis points at June 30, 2016).

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 when made; a change of control; or certain other material adverse changes in our business. Our senior 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 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.

Senior Subordinated Notes

In April 2015, we redeemed our $700 million aggregate principal amount of 6 % Senior Subordinated Notes due 2020. In connection with the redemption, we paid a premium of $24 million. The premium was recorded under the caption "Other income (expense) — Other, net" on our consolidated statement of operations. In addition, associated unamortized offering costs and discounts of approximately $8 million were charged to interest expense during the second quarter of 2015 as a result of the redemption.

11. Commitments and Contingencies

In May 2015, a lawsuit was filed against the Company alleging certain plugging and abandonment predecessor-in-interest liabilities related to offshore assets sold by the Company in 2010. The lawsuit alleges damages of approximately $23 million. The Company has responded to the petition, denied the allegations and is vigorously defending the case. The court has held that the Company must bear a "portion" of the plugging and abandonment costs, but the "exact percentage" of such costs should be determined in arbitration. The court case is stayed pending arbitration. An estimate of reasonably possible losses, if any, cannot be made at this time.

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.

12. Stockholders' Equity Activity

During the first quarter of 2016, we issued 34.5 million additional shares of common stock through a public equity offering. We received net proceeds of approximately $776 million, a portion of which was used to repay borrowings under our credit facility and money market lines of credit. The remainder was used for other corporate purposes, which included the acquisition of additional properties in the Anadarko Basin STACK play.

During the first quarter of 2015, we issued 25.3 million additional shares of common stock through a public equity offering. We received net proceeds of approximately $815 million, which were used primarily to repay all borrowings under our credit facility and money market lines of credit that were outstanding at that time.

13. 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,	
	2016	2015	2016	2015
	(In millions, except per share data)			
Net income (loss)	$(667)	$(992)	$(1,291)	$(1,472)
Weighted-average shares (denominator):				
Weighted-average shares — basic	198	163	188	154
Dilution effect of stock options and unvested restricted stock awards and restricted stock units outstanding at end of period[(1)]	—	—	—	—
Weighted-average shares — diluted	198	163	188	154
Earnings (loss) per share:				
Basic	$(3.36)	$(6.09)	$(6.87)	$(9.55)
Diluted	$(3.36)	$(6.09)	$(6.87)	$(9.55)

(1) The effect of unvested restricted stock awards or restricted stock units and stock options has not been included in the calculation of shares outstanding for diluted EPS for the three and six months ended June 30, 2016 and 2015, as their effect would have been anti-dilutive. Had we recognized net income for the quarter, incremental shares attributable to the assumed vesting of unvested restricted stock awards and restricted stock units and the assumed exercise of outstanding stock options would have increased diluted weighted-average shares outstanding by 1.6 million and 1.3 million shares for the three and six months ended June 30, 2016, respectively, and 1.5 million and 1.4 million shares for the three and six months ended June 30, 2015, respectively.

Table of Contents

14. Stock-Based Compensation

Our stock-based compensation expense consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions)			
Equity awards	$9	$12	$18	$22
Liability awards:				
Cash-settled restricted stock units	7	5	10	12
Stockholder Value Appreciation Program	—	(5)	—	—
Total liability awards	7	—	10	12
Total stock-based compensation	16	12	28	34
Capitalized in oil and gas properties	(5)	(2)	(9)	(9)
Net stock-based compensation expense	$11	$10	$19	$25

As of June 30, 2016, we had approximately $63 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation awards that vest within four years. On June 30, 2016, the last reported sales price of our common stock on the New York Stock Exchange was $44.18 per share.

Equity Awards

Equity awards consist of service-based and performance- or market-based restricted stock awards and restricted stock units, stock options and stock purchase options under the Employee Stock Purchase Plan (ESPP). At June 30, 2016, we had approximately (1) 5.7 million shares available for issuance under our 2011 Omnibus Stock Plan, as amended (2011 Plan), if all future awards are stock options, or (2) 3 million shares available for issuance under our 2011 Plan if all future awards are restricted stock awards or restricted stock units.

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

	Service-Based Shares	Weighted-Average Grant Date Fair Value per Share	Performance/ Market-Based Shares[(1)]	Weighted-Average Grant Date Fair Value per Share	Total Shares
	(In thousands, except per share data)				
Non-vested shares outstanding at January 1, 2016	1,700	$ 30.30	1,074	$ 23.76	2,774
Granted	473	29.37	436	28.94	909
Forfeited	(48)	32.54	(44)	56.49	(92)
Vested	(316)	31.71	(574)	21.36	(890)
Non-vested shares outstanding at June 30, 2016	1,809	$ 29.75	892	$ 26.23	2,701

(1)

In February 2016, we granted approximately 436,000 shares of restricted stock units, which based on achievement of certain performance criteria, could vest within a range of 0% to 200% of shares granted.

Employee Stock Purchase Plan. During the first six months of 2016, options to purchase approximately 60,000 shares of our common stock were issued under our ESPP. The fair value of each option was $9.20 per share. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free interest rate of 0.47%, an expected life of six months and weighted-average volatility of 47.9%.

Stock Options. As of June 30, 2016, we had approximately 190,000 stock options outstanding and exercisable. No stock options have been granted since 2008, except for ESPP options as discussed above.

Liability Awards

Liability awards consist of performance awards that are settled in cash instead of shares, as discussed below.

Cash-Settled Restricted Stock Units. The value of the cash-settled restricted stock units, and the associated stock-based compensation expense, is based on the Company's stock price at the end of each period. As of June 30, 2016, we had a liability of $22 million for future cash settlement upon vesting of awards. The following table provides information about cash-settled restricted stock unit activity.

	Cash-Settled Restricted Stock Units (In thousands)
Non-vested units outstanding at January 1, 2016	708
Granted	295
Forfeited	(75)
Vested	(7)
Non-vested units outstanding at June 30, 2016	921

15. Restructuring Costs

In May 2016, we announced plans to consolidate and reorganize domestic operating functions to our headquarters in The Woodlands, Texas, which will result in a significant reduction of employees located in the Tulsa, Oklahoma office. Our decision to restructure the organization was primarily in response to the current oil and gas commodity price environment. Substantially all restructuring-related costs are expected to be incurred by the end of 2016. We will abandon our Tulsa, Oklahoma office space during the fourth quarter of 2016 and record a liability for the remaining contracted payments net of expected sublease income.

In April 2015, we announced plans to combine our onshore Gulf Coast and Rocky Mountain business units into our newly created Western Region, which is managed from The Woodlands, Texas. Our decision to restructure the organization, which only affected our domestic business, was primarily in response to the oil and gas commodity price environment. Substantially all restructuring-related costs were incurred by December 31, 2015. We abandoned our Denver, Colorado office space during the third quarter of 2015 and recorded a loss for the remaining contracted payments net of expected sublease income. We closed our North Houston (Greenspoint area) office in the first quarter of 2016.

Restructuring costs recorded in our consolidated statement of operations are set forth below.

Type of Restructuring Cost	Location in the Consolidated Statement of Operations	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
		(In millions)			
Severance and related benefit costs	Operating expenses - General and administrative	$8	$ 3	$8	$ 3
Relocation costs	Operating expenses - General and administrative	1	1	1	1

Office-lease abandonment costs	Operating expenses - General and administrative	3	—	3	—
Other associated costs	Operating expenses - Depreciation, depletion and amortization	—	1	—	1
Total		$12	$ 5	$12	$ 5

20

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

The following tables summarize our restructuring costs and related accruals.

	Severance and Related Benefit Costs	Office-lease Abandonment Costs	Relocation Costs	Other Associated Costs	Total
	(In millions)				
Restructuring liability at January 1, 2015	$—	$ —	$ —	$ —	$—
Additions	3	—	1	1	5
Settlements	—	—	(1)	(1)	(2)
Revisions	—	—	—	—	—
Restructuring liability at June 30, 2015	$3	$ —	$ —	$ —	$3
Cumulative costs as of June 30, 2015	$3	$ —	$ 1	$ 1	$5
Restructuring liability at January 1, 2016	$1	$ 13	$ —	$ —	$14
Additions	8	—	1	—	9
Settlements	(2)	(3)	(1)	—	(6)
Revisions	—	3	—	—	3
Restructuring liability at June 30, 2016	$7	$ 13	$ —	$ —	$20
Cumulative costs as of June 30, 2016	$15	$ 17	$ 6	$ 1	$39
Expected total costs as of June 30, 2016	$20	$ 21	$ 13	$ 3	$57

16. Segment Information

While we only have operations in the oil and gas exploration and production industry, we are organizationally structured along geographic operating segments. Our current operating segments are the United States and China. The accounting policies of our operating segments are the same as those described in Note 1, “Organization and Summary of Significant Accounting Policies,” in our Annual Report on Form 10-K for the year ended December 31, 2015.

The following tables provide the geographic operating segment information for the three and six-month periods ended June 30, 2016 and 2015. Income tax allocations have been determined based on statutory rates in the applicable geographic segment. Our income tax allocation of our China operations is based on the combined statutory rates for China and the United States.

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

	Domestic	China	Total
	(In millions)		
Three Months Ended June 30, 2016:			
Oil, gas and NGL revenues	$309	$72	$381
Operating expenses:			
Lease operating	46	16	62
Transportation and processing	66	—	66
Production and other taxes	11	—	11
Depreciation, depletion and amortization	126	34	160
General and administrative	56	2	58
Ceiling test and other impairments	501	21	522
Allocated income tax (benefit)	(183)	(1)	
Net income (loss) from oil and gas properties	$(314)	$—	
Total operating expenses			879
Income (loss) from operations			(498)
Interest expense, net of interest income, capitalized interest and other			(27)
Commodity derivative income (expense)			(133)
Income (loss) from operations before income taxes			$(658)
Total assets	$4,095	$190	$4,285
Additions to long-lived assets	$699	$—	$699

	Domestic	China	Total
	(In millions)		
Three Months Ended June 30, 2015:			
Oil, gas and NGL revenues	$370	$99	$469
Operating expenses:			
Lease operating	56	17	73
Transportation and processing	52	—	52
Production and other taxes	17	—	17
Depreciation, depletion and amortization	207	41	248
General and administrative	49	2	51
Ceiling test and other impairments	1,521	—	1,521
Other	3	—	3
Allocated income tax (benefit)	(568)	23	
Net income (loss) from oil and gas properties	$(967)	$16	
Total operating expenses			1,965
Income (loss) from operations			(1,496)
Interest expense, net of interest income, capitalized interest and other			(60)
Commodity derivative income (expense)			(10)
Income (loss) from operations before income taxes			$(1,566)
Total assets	$6,776	$659	$7,435
Additions to long-lived assets	$340	$15	$355

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

	Domestic	China	Total
	(In millions)		
Six Months Ended June 30, 2016:			
Oil, gas and NGL revenues	$544	$121	$665
Operating expenses:			
Lease operating	93	30	123
Transportation and processing	129	—	129
Production and other taxes	21	—	21
Depreciation, depletion and amortization	259	78	337
General and administrative	99	3	102
Ceiling test and other impairments	962	66	1,028
Other	1	—	1
Allocated income tax (benefit)	(377)	(34)	
Net income (loss) from oil and gas properties	$(643)	$(22)	
Total operating expenses			1,741
Income (loss) from operations			(1,076)
Interest expense, net of interest income, capitalized interest and other			(58)
Commodity derivative income (expense)			(150)
Income (loss) from operations before income taxes			$(1,284)
Total assets	$4,095	$190	$4,285
Additions to long-lived assets	$960	$—	$960

	Domestic	China	Total
	(In millions)		
Six Months Ended June 30, 2015:			
Oil, gas and NGL revenues	$673	$145	$818
Operating expenses:			
Lease operating	121	27	148
Transportation and processing	101	—	101
Production and other taxes	30	—	30
Depreciation, depletion and amortization	419	66	485
General and administrative	110	4	114
Ceiling test and other impairments	2,313	—	2,313
Other	6	1	7
Allocated income tax (benefit)	(898)	28	
Net income (loss) from oil and gas properties	$(1,529)	$19	
Total operating expenses			3,198
Income (loss) from operations			(2,380)
Interest expense, net of interest income, capitalized interest and other			(89)
Commodity derivative income (expense)			143
Income (loss) from operations before income taxes			$(2,326)
Total assets	$6,776	$659	$7,435
Additions to long-lived assets	$736	$27	$763

17. Supplemental Cash Flow Information

The following table presents information about investing and financing activities that affect recognized assets and liabilities but do not result in cash receipts or payments for the indicated periods.

	Six Months Ended June 30,	
	2016	2015
	(In millions)	
Non-cash investing and financing activities excluded from the statement of cash flows:		
(Increase) decrease in receivables for property sales	$ 6	$ 8
(Increase) decrease in accrued capital expenditures	33	169
(Increase) decrease in accrued insurance proceeds	—	57
(Increase) decrease in asset retirement costs	(8)	1

18. Subsequent Events

On August 2, 2016, we entered into agreements with two separate purchasers to divest substantially all of our assets in Texas for combined cash proceeds of approximately $390 million, subject to customary purchase price adjustments. The sales of our Texas 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 both transactions to close in the third quarter of 2016.

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 operations are focused primarily on large scale, onshore liquids-rich resource plays in the United States. Our principal areas of operation are the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota, the Uinta Basin of Utah and the Maverick and Gulf Coast basins of Texas. In addition, we have oil developments offshore China.

Significant second quarter 2016 highlights include:

- additional properties acquired in the Anadarko Basin STACK play for an adjusted purchase price of $490 million;
- consolidation of our Tulsa regional office to our headquarters in The Woodlands, Texas announced in an effort to improve business and cost efficiencies;
- total consolidated production increased 9% to 15.1 MMBOE compared to the second quarter of 2015, and total domestic production increased 11% to 13.5 MMBOE compared to the second quarter of 2015;
- Anadarko Basin production was 7.6 MMBOE in the second quarter of 2016, up 53% over the same period of 2015 and 7% over the first quarter of 2016. Anadarko Basin crude oil production increased 64% over the second quarter of 2015;
- domestic lease operating expense was $3.42 per BOE, a 25% improvement compared to the second quarter of 2015; and
- crude oil and natural gas derivative contracts generated realized income of $64 million for the second quarter of 2016.

All consolidated and domestic BOE calculations above exclude natural gas produced and consumed in operations of 1.3 Bcf for the second quarter of 2016 and 1.9 Bcf for the second quarter of 2015.

Results of Operations

Domestic Revenues and Production. Revenues during the second quarter of 2016 were $61 million lower than the same period of 2015. The lower revenues were primarily attributable to a 25% decrease in average realized prices. We increased our domestic liquids production by 7% and gas production by 16% compared to the second quarter of 2015, reducing the impact of lower commodity prices by $2 million and $11 million, respectively. Our increased domestic liquids production resulted from an increase in NGL production of 41%, partially offset by a decrease in crude oil production of 5%. Our Anadarko Basin oil, gas and NGL production increased by 64%, 47% and 51%, respectively. Williston Basin production increased by 8% primarily due to the results of our drilling program and reduced flare volumes. Production in our other domestic basins declined or remained flat as compared to the second quarter of 2015 due to reduced drilling in those areas.

Revenues during the six months ended June 30, 2016 were $129 million lower than the same period of 2015. The lower revenues were attributable to a 29% decrease in average realized prices compared to the six months ended June 30, 2015. We increased our domestic liquids production by 11% and gas production by 18% compared to 2015, reducing the impact of lower commodity prices by $33 million and $26 million, respectively. Our Anadarko Basin oil, gas and NGL production increased by 67%, 47% and 43%, respectively. Williston Basin production increased by 14% primarily due to the results of our drilling program and reduced flare volumes. Production in our other domestic basins declined or remained flat as compared to 2015 due to reduced drilling in those areas.

China Revenues and Production/Liftings. Revenues during the second quarter of 2016 were $27 million lower than the same quarter of 2015 primarily due to a 27% decrease in the realized crude oil price. Lifted volumes remained flat period over period.

Revenues during the six months ended June 30, 2016 were $24 million lower than the same period of 2015, primarily due to a 35% decrease in the realized crude oil price. China liftings for the first six months of 2016 were 723 MBbls higher than the comparable period of 2015 primarily due to six months of production in 2016 from the Pearl field, which achieved peak production levels in May 2015.

The following table reflects our production/liftings and average realized commodity prices.

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Percentage Increase (Decrease)	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Percentage Increase (Decrease)
Production/Liftings:						
Domestic:[1]						
Crude oil and condensate (MBbls)	5,250	5,532	(5)%	10,585	10,482	1 %
Natural gas (Bcf)	32.4	27.9	16 %	65.3	55.2	18 %
NGLs (MBbls)	2,792	1,976	41 %	5,268	3,825	38 %
Total (MBOE)	13,454	12,160	11 %	26,742	23,515	14 %
China:[2]						
Crude oil and condensate (MBbls)	1,629	1,643	(1)%	3,272	2,549	28 %
Total:						
Crude oil and condensate (MBbls)	6,879	7,175	(4)%	13,857	13,031	6 %
Natural gas (Bcf)	32.4	27.9	16 %	65.3	55.2	18 %
NGLs (MBbls)	2,792	1,976	41 %	5,268	3,825	38 %
Total (MBOE)	15,083	13,803	9 %	30,014	26,064	15 %
Average Realized Prices:						
Domestic:[3]						
Crude oil and condensate (per Bbl)	$38.17	$47.59	(20)%	$31.89	$43.16	(26)%
Natural gas (per Mcf)	1.69	2.36	(28)%	1.76	2.53	(30)%
NGLs (per Bbl)	19.23	19.17	— %	17.12	19.55	(12)%
Crude oil equivalent (per BOE)	22.96	30.43	(25)%	20.35	28.60	(29)%
China:						
Crude oil and condensate (per Bbl)	$43.95	$60.24	(27)%	$36.89	$56.87	(35)%
Total:						
Crude oil and condensate (per Bbl)	$39.54	$50.49	(22)%	$33.07	$45.84	(28)%
Natural gas (per Mcf)	1.69	2.36	(28)%	1.76	2.53	(30)%
NGLs (per Bbl)	19.23	19.17	— %	17.12	19.55	(12)%
Crude oil equivalent (per BOE)	25.23	33.98	(26)%	22.15	31.37	(29)%

---

(1) Excludes natural gas produced and consumed in operations of 1.3 Bcf and 1.9 Bcf during the three months ended June 30, 2016 and 2015, respectively, and 2.8 Bcf and 4.1 Bcf during the six months ended June 30, 2016 and 2015, respectively.

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

(3) Had we included the realized effects of derivative contracts, the average realized prices for our domestic crude oil and natural gas production would have been as follows:

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Crude oil and condensate (per Bbl)	$49.12	$64.18	$44.00	$61.03
Natural gas (per Mcf)	1.86	3.50	2.02	3.56

Operating Expenses.

Three months ended June 30, 2016 compared to June 30, 2015

The following table presents information about our operating expenses.

	Unit-of-Production			Total Amount		
	Three Months Ended June 30,		Percentage Increase (Decrease)	Three Months Ended June 30,		Percentage Increase (Decrease)
	2016	2015		2016	2015	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$3.42	$4.58	(25)%	$46	$ 56	(17)%
Transportation and processing	4.86	4.22	15 %	66	52	28 %
Production and other taxes	0.82	1.35	(39)%	11	17	(33)%
Depreciation, depletion and amortization	9.35	17.05	(45)%	126	207	(39)%
General and administrative	4.21	4.09	3 %	56	49	14 %
Ceiling test and other impairments	37.28	125.05	(70)%	501	1,521	(67)%
Other	—	0.24	(100)%	—	3	(100)%
Total operating expenses	59.94	156.58	(62)%	806	1,905	(58)%
China:						
Lease operating	$9.57	$10.61	(10)%	$16	$ 17	(10)%
Depreciation, depletion and amortization	20.56	25.16	(18)%	34	41	(19)%
General and administrative	0.97	0.96	1 %	2	2	— %
Ceiling test impairment	12.79	—	100 %	21	—	100 %
Total operating expenses	43.89	36.73	19 %	73	60	18 %
Total:						
Lease operating	$4.08	$5.28	(23)%	$62	$ 73	(16)%
Transportation and processing	4.34	3.72	17 %	66	52	28 %
Production and other taxes	0.74	1.21	(39)%	11	17	(33)%
Depreciation, depletion and amortization	10.56	18.01	(41)%	160	248	(36)%
General and administrative	3.86	3.72	4 %	58	51	13 %
Ceiling test and other impairments	34.63	110.18	(69)%	522	1,521	(66)%
Other	—	0.21	(100)%	—	3	(100)%
Total operating expenses	58.21	142.33	(59)%	879	1,965	(55)%

Domestic Operations. The primary components within our operating expenses are as follows:

- Lease operating expense decreased 17% despite an 11% increase in total production. On a per BOE basis, lease operating expense was 25% lower due to our focused growth in the Anadarko Basin, which has significantly lower operating costs than our other basins. Additionally, there was a reduction of lease operating expense per BOE across all basins due to our focus on cost-reduction initiatives combined with downward service cost pressures in the industry as a result of a lower commodity price environment.

- Transportation and processing expense per BOE increased 15% primarily due to increased natural gas and NGL volumes in our SCOOP and STACK plays. Second quarter 2016 gas production from these two plays increased 47% compared to the second quarter of 2015, while NGL production increased 51%. Additionally, oil transportation costs increased in the Williston Basin due to new pipeline marketing agreements in the second half of 2015. These pipeline agreements allow us to transport oil to more favorable markets and thus receive a higher net price.

- Production and other taxes decreased 39% per BOE due to lower revenue. As a percent of total revenue, production and other taxes were 3.6% and 4.4% for the three months ended June 30, 2016 and 2015, respectively. Our 2016 rate is lower as our development has been focused in areas with lower taxes due to horizontal well credits.

- Depreciation, depletion and amortization (DD&A) decreased 45% on a per BOE basis primarily due to the impact of non-cash ceiling test impairments during 2015 and the first quarter of 2016. We expect a further decrease in the third quarter of 2016 as a result of the impairment recorded in the second quarter of 2016.

- General and administrative (G&A) expenses increased 14% during the second quarter of 2016 compared to the second quarter of 2015. Severance and related benefit costs associated with our reduction in workforce and restructuring were $12 million during the three months ended June 30, 2016 as compared to $5 million during the same period of 2015. Stock-based compensation expense was higher during the second quarter of 2016, due to a fair value decrease for awards under our Stockholder Value Appreciation Program during the second quarter of 2015. For the three months ended June 30, 2016, we capitalized $19 million of direct internal costs as compared to $17 million during the comparable quarter of 2015. This increase in capitalization of costs is primarily due to the increase in stock-based compensation.

- During the second quarter of 2016, we recorded a ceiling test impairment of $501 million due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was a 7% decrease in both crude oil and natural gas SEC pricing since March 31, 2016. These commodity price decreases were partially offset by the impact of current service cost reductions in reserve estimates. During the second quarter of 2015, we recorded a ceiling test impairment of $1.5 billion due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was a 13% decrease in both crude oil and natural gas SEC pricing since March 31, 2015, partially offset by the impact of service cost reductions in reserve estimates.

China Operations. The primary components within our operating expenses are as follows:

- On a per BOE basis, lease operating expense was 10% lower primarily related to Pearl field cost reductions from renegotiated contracts, combined with lower production handling fees resulting from lower crude oil prices.

- DD&A expense per BOE decreased by 18% primarily due to the impact of non-cash ceiling test impairments during 2015 and the first quarter of 2016.

- During the second quarter of 2016, we recorded a non-cash ceiling test impairment of $21 million due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was a 7% decrease in crude oil SEC pricing since March 31, 2016.

Six months ended June 30, 2016 compared to June 30, 2015

The following table presents information about our operating expenses.

	Unit-of-Production Six Months Ended June 30, 2016 (Per BOE)	2015	Percentage Increase (Decrease)	Total Amount Six Months Ended June 30, 2016 (In millions)	2015	Percentage Increase (Decrease)
Domestic:						
Lease operating	$3.47	$5.15	(33)%	$93	$121	(23)%
Transportation and processing	4.82	4.27	13 %	129	101	28 %
Production and other taxes	0.77	1.27	(39)%	21	30	(31)%
Depreciation, depletion and amortization	9.70	17.81	(46)%	259	419	(38)%
General and administrative	3.71	4.68	(21)%	99	110	(10)%
Ceiling test and other impairments	35.98	98.36	(63)%	962	2,313	(58)%
Other	0.02	0.24	(92)%	1	6	(89)%
Total operating expenses	$58.47	$131.78	(56)%	$1,564	$3,100	(50)%
China:						
Lease operating	$9.24	$10.54	(12)%	$30	$27	12 %
Depreciation, depletion and amortization	23.67	26.14	(9)%	78	66	16 %
General and administrative	0.91	1.56	(42)%	3	4	(25)%
Ceiling test impairment	20.19	—	100 %	66	—	100 %
Other	—	0.45	(100)%	—	1	(100)%
Total operating expenses	$54.01	$38.69	40 %	$177	$98	79 %
Total:						
Lease operating	$4.08	$5.66	(28)%	$123	$148	(17)%
Transportation and processing	4.29	3.86	11 %	129	101	28 %
Production and other taxes	0.70	1.16	(40)%	21	30	(31)%
Depreciation, depletion and amortization	11.22	18.62	(40)%	337	485	(31)%
General and administrative	3.40	4.37	(22)%	102	114	(10)%
Ceiling test and other impairments	34.26	88.75	(61)%	1,028	2,313	(56)%
Other	0.03	0.26	(88)%	1	7	(88)%
Total operating expenses	$57.98	$122.68	(53)%	$1,741	$3,198	(46)%

Domestic Operations. The primary components within our operating expenses are as follows:

- Lease operating expense decreased 23% despite a 14% increase in total production. On a per BOE basis, lease operating expense was 33% lower due to our focused growth in the Anadarko Basin, which has significantly lower operating costs than our other basins. Additionally, there was a reduction of lease operating expense per BOE across all basins due to our focus on cost-reduction initiatives combined with downward service cost pressures in the industry as a result of a lower commodity price environment.

- Transportation and processing expense per BOE increased 13% primarily due to increased natural gas and NGL volumes in our SCOOP and STACK plays. For the first six months of 2016, gas production from these two plays increased 47% compared to the same period of 2015, while NGL production increased 43%. Additionally, oil transportation costs increased in the Williston Basin due to new pipeline marketing agreements initiated in the second half of 2015. These pipeline agreements allow us to transport oil to more favorable markets and thus receive a higher net price.

- Production and other taxes decreased 39% per BOE due to lower total revenues. As a percent of total revenue, production and other taxes were 3.8% and 4.4% for the six months ended June 30, 2016 and 2015, respectively. The lower rate in 2016 was due to development in areas with lower production taxes due to horizontal well credits.

- Depreciation, depletion and amortization decreased 46% on a per BOE basis primarily due to the impact of non-cash ceiling test impairments during 2015 and the first quarter of 2016. We expect a further decrease in the third quarter of 2016 as a result of the impairment recorded in the second quarter of 2016.

- General and administrative expenses decreased 10% during the first six months of 2016 compared to the first six months of 2015. Employee-related expenses were approximately $13 million lower due to a reduction of headcount and lower severance costs as compared to the six months ended June 30, 2015. In addition, stock-based compensation expense decreased due to a reduction of the number of awards outstanding. For the six months ended June 30, 2016, we capitalized $36 million of direct internal costs as compared to $42 million during the comparable period of 2015. This decrease in capitalization of costs is consistent with the decrease in stock-based compensation and lower development activity in 2016.

- During the first six months of 2016, we recorded non-cash ceiling test impairments of $962 million due to a net decrease in the discounted value of our proved reserves. The decrease primarily resulted from a 14% decrease in both crude oil and natural gas SEC pricing since December 31, 2015. These commodity price decreases were partially offset by the impact of current service cost reductions in reserve estimates. During the first six months of 2015, we recorded a non-cash ceiling test impairment of $2.3 billion due to a net decrease in the discounted value of our proved reserves. The decrease in 2015 primarily resulted from a 25% decrease in crude oil SEC pricing and a 22% decrease in natural gas SEC pricing since December 31, 2014. These commodity price decreases were partially offset by the impact of service cost reductions in reserve estimates. Additionally, during the first quarter of 2015, we recorded a $4 million rig impairment associated with our decision to indefinitely lay down both of our company-owned drilling rigs in the Uinta Basin.

China Operations. The primary components within our operating expenses are as follows:

- On a per BOE basis, lease operating expense was 12% lower primarily due to higher production volumes, cost reductions in our Pearl field from renegotiated contracts and lower production handling fees resulting from lower crude oil prices.

- DD&A expense per BOE decreased by 9% primarily due to the impact of the non-cash ceiling test impairments during 2015 and the first quarter of 2016.

- During the six months ended June 30, 2016, we recorded non-cash ceiling test impairments of $66 million due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was a 14% decrease in crude oil SEC pricing since December 31, 2015.

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,	
	2016	2015	2016	2015
	(In millions)			
Gross interest expense:				
Credit arrangements	$3	$2	$9	$6
Senior notes	35	35	70	63
Senior subordinated notes	—	9	—	21

Total gross interest expense	38	46	79	90
Capitalized interest	(11)	(8)	(20)	(15)
Net interest expense	$27	$38	$59	$75

Gross interest expense decreased for the three and six months ended June 30, 2016, as compared to the three and six months ended June 30, 2015, primarily due to the redemption of our 6 % Senior Subordinated Notes due 2020 in April 2015. This decrease was partially offset by the additional interest expense associated with our $700 million 5 % Senior Notes due 2026 issued in March 2015 and $3 million of financing costs related to the fifth amendment to our Credit Agreement in 2016.

Capitalized interest increased for the three and six months ended June 30, 2016, as compared to the three and six months ended June 30, 2015, due to an increase in the average amount of unproved oil and gas properties.

Commodity Derivative Income (Expense). The fluctuations in commodity derivative income (expense) 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. The amount of unrealized gain (loss) on derivatives is the result of the change in the total fair value of our derivative positions from the prior period.

Three months ended June 30, 2016

The $133 million loss recognized in “Commodity derivative income (expense)” in our consolidated statement of operations related to our derivative financial instruments is comprised of a $64 million realized gain and a $197 million unrealized loss. The components of the change in the fair value of our net derivative asset (liability) follow:

	Positions Settled in the Three Months Ended June 30, 2016	Positions Settling After June 30, 2016	Total
	(In millions)		
Net derivative asset at March 31, 2016	$ 70	$ 198	$ 268
Settled positions[1]	(70)	—	(70)
Change in fair value of remaining positions and fair value of new positions	—	(127)	(127)
Total unrealized gain (loss)	(70)	(127)	(197)
Net derivative asset (liability) at June 30, 2016	$ —	$ 71	$ 71

(1) Represents the fair value of positions included in the net derivative asset as of March 31, 2016 that have settled during the three months ended June 30, 2016. Actual settlement amounts differ due to the changes in the fair value of the positions between the balance sheet date and the settlement date and are reflected in the realized gain (loss) noted in Note 4, "Derivative Financial Instruments."

Six months ended June 30, 2016

The $150 million loss recognized in “Commodity derivative income (expense)” in our consolidated statement of operations related to our derivative financial instruments is comprised of a $146 million realized gain and a $296 million unrealized loss. The components of the change in the fair value of our net derivative asset (liability) follow:

	Positions Settled in the Six Months Ended June	Positions Settling After June 30, 2016	Total

	30, 2016 (In millions)		
Net derivative asset at December 31, 2015	$150	$ 217	$367
Settled positions[1]	(150)	—	(150)
Change in fair value of remaining positions and fair value of new positions	—	(146)	(146)
Total unrealized gain (loss)	(150)	(146)	(296)
Net derivative asset (liability) at June 30, 2016	$—	$ 71	$71

(1) Represents the fair value of positions included in the net derivative asset as of December 31, 2015 that have settled during the six months ended June 30, 2016. Actual settlement amounts differ due to the changes in the fair value of the positions between the balance sheet date and the settlement date and are reflected in the realized gain (loss) noted in Note 4, "Derivative Financial Instruments."

Taxes. The effective tax rates for the second quarter ended June 30, 2016 and 2015 were (1.4)% and 36.7%, respectively. Our effective tax rate for both periods was different than the federal statutory rate of 35% due to the change in valuation allowances, non-deductible expenses, state income taxes, the differences between international and U.S. federal statutory rates, and the impact of our China earnings being taxed both in the U.S. and China. Our future effective tax rates may also be impacted by additional ceiling test impairments or other items which generate deferred tax assets, deferred tax asset valuation allowances, and/or reversal of such valuation allowances. The following table summarizes our tax activity that derives our effective tax rate for the second quarter of 2016.

	Domestic	China	Total
		(In millions)	
Total income (loss) before income taxes	$ (658)	$ —	$ (658)
U.S. federal statutory tax rate	35 %	35 %	35 %
Tax expense (benefit) at statutory tax rate	(230)	—	(230)
State and local income taxes, net of tax effect	(4)	—	(4)
Change in valuation allowances	243	9	252
Foreign tax on foreign earnings	—	—	—
Other	(9)	—	(9)
Total provision (benefit) for income taxes	$ —	$ 9	$ 9
Effective tax rate	— %	— %	(1.4)%

The effective tax rates for the six months ended June 30, 2016 and 2015 were (0.6)% and 36.7%, respectively. Our effective tax rate for both periods was different than the federal statutory rate of 35% due to the change in valuation allowances, non-deductible expenses, state income taxes, the differences between international and U.S. federal statutory rates, and the impact of our China earnings being taxed both in the U.S. and China. Our future effective tax rates may also be impacted by additional ceiling test impairments or other items which generate deferred tax assets, deferred tax asset valuation allowances, and/or reversal of such valuation allowances. The following table summarizes our tax activity that derives our effective tax rate for the first six months of 2016.

	Domestic	China	Total
		(In millions)	
Total income (loss) before income taxes	$ (1,228)	$ (56)	$ (1,284)
U.S. federal statutory tax rate	35 %	35 %	35 %
Tax expense (benefit) at statutory tax rate	(430)	(19)	(449)
State and local income taxes, net of tax effect	(9)	—	(9)
Change in valuation allowances	459	28	487
Foreign tax on foreign earnings	—	(15)	(15)
Other	(7)	—	(7)
Total provision (benefit) for income taxes	$ 13	$ (6)	$ 7
Effective tax rate	(1.1)%	10.7 %	(0.6)%

See Note 8, "Income Taxes," to our consolidated financial statements earlier in this report for additional disclosures.

Liquidity and Capital Resources

Beginning in the fourth quarter of 2014, crude oil prices declined significantly primarily due to global supply and demand imbalances. Crude oil prices continued to decline in 2015 and remained depressed in the second quarter of 2016, as compared to periods prior to the fourth quarter of 2014. Given the future uncertainty regarding the timing and magnitude of an eventual recovery of crude oil prices, our planned capital spending for 2016 was reduced from 2015 levels to reduce deficit spending and preserve long-term liquidity.

During the first six months of 2016, as a part of our strategy to optimize long-term liquidity, we issued 34.5 million additional shares of common stock through a public equity offering and received net proceeds of approximately $776 million. A portion was used to repay borrowings under our credit facility and money market lines of credit. The remainder was used for general corporate purposes, which included the acquisition of additional properties in the Anadarko Basin STACK play. We use cash flows from operations to fund our capital budget.

Our updated 2016 capital budget, excluding estimated capitalized interest and direct internal costs of approximately $100 million, is expected to be approximately $700 million - $750 million. 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 are 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 or fluctuations in our cash flows.

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 alternative sources of liquidity, including selling non-strategic assets or potentially accessing debt and equity capital markets in light of current and expected economic conditions. We believe that our liquidity position and ability to generate cash flows from our operations will be adequate to fund 2016 operations and continue to meet our other obligations. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Other Financing Activities. In March 2016, we entered into the fifth amendment to our Credit Agreement. This amendment changed certain definitions related to our financial covenants and decreased our interest rate coverage ratio from 3.0:1.0 to 2.5:1.0. Our borrowing capacity remains at $1.8 billion and the facility maturity date remains June 2020. We incurred approximately $3 million of financing costs related to this amendment, which were included in "Interest expense" on our consolidated statement of operations. At June 30, 2016, we had available borrowing capacity (before any amounts drawn) under our money market lines of credit of $135 million, which was reduced from $195 million at December 31, 2015 due to the downgrading of our debt rating by rating agencies during the six months ended June 30, 2016.

At June 30, 2016, we had no borrowings outstanding under our money market lines of credit, no borrowings outstanding under our revolving credit facility and no letters of credit outstanding under our credit facility.

We have no scheduled maturities of senior notes until 2022. For a more detailed description of the terms of our credit arrangements and senior notes, see Note 10, “Debt,” to our consolidated financial statements appearing earlier in this report.

As of July 28, 2016, we had no outstanding borrowings and available borrowing capacity of $1.8 billion under our revolving credit facility, and cash and cash equivalents of $174 million. As of July 28, 2016, we had no outstanding borrowings under our money market lines of credit and available capacity of $135 million.

Working Capital. Our working capital balance fluctuates primarily 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. At June 30, 2016, we had negative working capital of $19 million compared to negative working capital of $22 million at December 31, 2015.

Cash Flows from Operations. Our primary source of capital and liquidity is cash flows from operations, which 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 $378 million for the six months ended June 30, 2016, which decreased compared to net cash flows from operations of $577 million for the same period in 2015. The primary driver of lower operating cash flows was lower revenues as a result of lower commodity prices.

Cash Flows from Investing Activities. Net cash used in investing activities for the six months ended June 30, 2016 was $945 million compared to $898 million for the same period in 2015. Cash used for capital expenditures in the first six months of 2016 was approximately $49 million higher than the same period in 2015. This increase is due to our Anadarko Basin acquisition, offset by our planned reductions in 2016 capital spending due to the current economic environment for our industry. For a more detailed description of the Anadarko Basin acquisition, see Note 6, “Oil and Gas Properties,” to our consolidated financial statements appearing earlier in this report.

Cash Flows from Financing Activities. Net cash provided by financing activities for the six months ended June 30, 2016 was $727 million compared to $349 million for the same period in 2015. During the six months ended June 30, 2016, we issued 34.5 million additional shares of common stock through a public equity offering and received net proceeds of approximately $776 million, a portion of which was used to repay all outstanding borrowings under our credit facility and money market lines of credit. The remainder was used for general corporate purposes, which included the acquisition of additional properties in the Anadarko Basin STACK play.

During the six months ended June 30, 2015, we received net proceeds of $815 million through the issuance of 25.3 million additional shares of common stock through a public equity offering, which were used to repay all borrowings under our credit facility and money market lines of credit. In addition, we received proceeds of $691 million through the issuance of senior notes, which we used to redeem $700 million of senior subordinated notes.

Capital Expenditures. Our capital investments for the first six months of 2016 increased 28% compared to the same period of 2015. The table below summarizes our capital investments.

	Six Months Ended June 30,	
	2016	2015
	(In millions)	
Exploration and development (exclusive of leasehold)	$367	$620
Acquisitions	503	1
Leasing proved and unproved property (leasehold)	25	77
Pipeline	—	2
Total	$895	$700

Ceiling Test Impairment

We recorded non-cash ceiling test impairments for the first and second quarters of 2016 for both the U.S. and China due to the ceiling not exceeding the net capitalized costs of oil and gas properties. At June 30, 2016, the ceiling value for our reserves was calculated based upon SEC pricing of $43.14 per barrel of oil and $2.24 per MMBtu for natural gas, adjusted for market differentials. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating and development costs, upward or downward reserve revisions, reserve adds, and tax attributes. Subject to these numerous factors and inherent limitations, we believe that impairments in the third quarter of 2016 could exceed $100 million based on the current forward strip pricing for crude oil and natural gas. Once recorded, a ceiling test impairment is not reversible at a later date even if oil and gas prices increase. Further declines in SEC pricing or downward revisions to our estimated proved reserves could result in additional ceiling test impairments of our oil and gas properties in subsequent periods.

Restructuring

In April 2015 and May 2016, we announced plans to restructure our organization primarily in response to the current commodity price environment and to improve margins, processes and cost efficiencies in operations. See Note 15, "Restructuring Costs," to our consolidated financial statements in Item 8 of this report for additional details regarding our restructuring activities.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. For further information, see “Management's Discussion and Analysis of Financial Condition and Results of Operations - Contractual Obligations” in our Annual Report on Form 10-K for the year ended December 31, 2015. There have been no material changes to the disclosure since year-end 2015.

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.

Oil and Gas Derivatives

We use derivative contracts to manage the variability in cash flows caused by commodity price fluctuations associated with our anticipated oil and gas production for the next 24 to 36 months. As of June 30, 2016, we had no outstanding derivative contracts related to our NGL production. We do not use derivative instruments for trading purposes.

For a further discussion of our derivative activities, see "Oil, Natural Gas and NGL Prices" in Item 3 of this report. See the discussion and tables in Note 4, “Derivative Financial Instruments,” and Note 5, “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 contracts and the estimated fair market value of those contracts as of June 30, 2016.

Between July 1, 2016 and July 28, 2016, we entered into additional natural gas derivative contracts. A listing of all our natural gas derivative contracts as of July 28, 2016 follows:

Period and Type of Instrument	Volume in MMMBtus	NYMEX Contract Price Per MMBtu			
				Collars	
		Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)
2016:					
Fixed-price swaps	36,800	$2.28	$ —	$ —	$ —
Collars	5,520	—	—	4.00	4.54
Swaptions[(1)]	—	3.75	—	—	—
2017:					
Fixed-price swaps	27,375	2.73	—	—	—
Collars	40,150	—	—	2.71	3.12
Swaptions[(1)]	—	3.75	—	—	—
2018:					
Collars	10,950	—	—	2.80	3.32

(1) During the third quarter of 2016, we sold natural gas swaption contracts that, if exercised on their expiration date in the fourth quarter of 2016, would protect 4,530 MMMBtus of November 2016 through March 2017 production from future commodity price volatility. These contracts give the counterparties the option to enter into swap contracts with us at $3.75 per MMBtu for production in the above period.

Accounting for Derivative Activities. As our derivative contracts are not designated for hedge accounting, they 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, 2016, we had net derivative assets of $71 million, of which 52%, based on total contracted volumes, was measured based upon a modified Black-Scholes valuation model and, as such, were classified as a Level 3 fair value measurement. The model considers various inputs including the following:

- 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, 2016. 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, 2015 and Note 4, “Derivative Financial Instruments,” and Note 5, “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

See Note 1, "Organization and Summary of Significant Accounting Policies," to our consolidated financial statements in Item 1 of this report for a discussion of new accounting requirements.

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, estimates of reserves, projected production, estimates of operating costs, planned exploratory or developed drilling, projected cash flows and liquidity, business strategy 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," "project," "target," "goal," "plan," "should," "will," "predict," "potentia expressions that convey the uncertainty of future events or outcomes. Although we believe that the expectations reflected in such forward-looking statements 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 but not limited to, the following:

- oil, natural gas and natural gas liquids prices;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- legislation or regulatory initiatives intended to address seismic activity;
- the timing and our success in discovering, producing and estimating reserves;
- sustained decline in commodity prices resulting in impairments of assets;
- ability to develop existing reserves or acquire new reserves;
- the availability and volatility of the securities, capital or credit markets and the cost of capital;
- maintaining sufficient liquidity to fund our operations and business strategies;
- the accuracy of and fluctuations in our reserves estimates due to sustained low commodity prices, incorrect assumptions and other causes;
- 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, climate change, seismicity and over-the-counter derivatives;
- land, legal, regulatory, and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- 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, instrument terms and liquidity in the commodity futures and commodity and financial derivatives markets;
- drilling risks and results;
- the prices and availability of goods and services;

- the cost and availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- our ability to monetize non-strategic assets, repay or refinance our existing indebtedness and the impact of changes in our investment ratings;
- labor conditions;
- weather conditions;
- competitive conditions;
- terrorism or civil or political unrest in a region or country;
- electronic, cyber or physical security breaches;
- changes in tax rates;
- inflation rates;
- 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 other factors affecting our business described under the caption “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates” included in our 2015 Annual Report on Form 10-K.

Should one or more of the risks described above occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

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 of 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.

Exploration well. 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.

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.

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.

MMBOE. One million barrels of oil equivalent.

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.

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.

SCOOP. South-Central Oklahoma Oil Province. A field in the Anadarko Basin of Oklahoma in which we operate.

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. The SEC provides a complete definition of the pricing methodology in their guidance “Modernization of Oil and Gas Reporting.”

STACK. Sooner Trend Anadarko Canadian Kingfisher. A play in the Anadarko Basin of Oklahoma in which we operate.

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 commonly used as a benchmark in oil pricing.

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 can limit or reduce 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, 2016, 10 of our 16 counterparties accounted for approximately 85% of our contracted volumes with the largest counterparty accounting for approximately 12%.

As of June 30, 2016, of our remaining expected 2016 crude oil production, 14,352 MBbls were protected against price volatility using collars and swaps, over 52% of which have associated sold puts. The sold puts limit our downward price protection below the weighted average of our sold puts of $74.63 per barrel. If the market price remains below $74.63 per barrel, we receive the market price for our associated production plus the difference between our sold puts and the associated floors or fixed-price swaps, which averages $15.35 per barrel. For 7,544 MBbls of our 2016 volumes, we have locked in an average minimum premium of $14.15 over the market price using purchased calls. The weighted average strike price of the purchased calls approximates the weighted average strike price of the sold puts, thereby effectively locking in the value. As of June 30, 2016, of our expected 2017 crude oil production, 12,753 MBbls were protected against price volatility using collars and swaps, over 51% of which have associated sold puts. The sold puts limit our downward price protection below the weighted average price of our sold puts of $73.83 per barrel. If the market price remains below $73.83 per barrel, we receive the market price for our associated production plus the difference between our sold puts and the associated floors or fixed-price swaps, which averages $15.06 per barrel. For 6,548 MBbls of our 2017 volumes, we have locked in an average minimum premium of $13.54 over the market price using purchased calls.

For a further discussion of our derivative activities, see the discussion and tables in Note 4, “Derivative Financial Instruments,” and Note 5, “Fair Value Measurements,” to our consolidated financial statements appearing earlier in this report. For further discussion of the types of derivative positions, refer to Note 4, “Derivative Financial Instruments,” within Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2015.

Interest Rates

We consider our interest rate exposure to be minimal because 100% of our obligations were at fixed rates as of June 30, 2016. A 10% increase in LIBOR would not impact our interest costs on debt outstanding as of June 30, 2016, but would decrease the fair value of our outstanding debt, as well as increase interest costs associated with future debt issuances or borrowings under our revolving credit facility and money market lines of credit.

Foreign Currency Exchange Rates

The functional currency for our China operations is the U.S. dollar. To the extent that business transactions in a foreign country are not denominated in the U.S. dollar, 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, 2016.

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). Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based upon our evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2016.

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 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based upon our 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

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 individually or in the aggregate exceed $100,000. If any fines or penalties are in fact imposed that are greater than $100,000, or we expect to be greater than $100,000, then we will disclose such fact in our subsequent filings. For a further discussion of our legal proceedings, see Note 11, "Commitments and Contingencies," to our consolidated financial statements appearing earlier in this report.

Item 1A. Risk Factors

The following risk factor updates, 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, 2015. Other than the risk factor discussed below, there have been no material changes with respect to the risk factors previously reported in our Annual Report on Form 10-K.

Legislation or regulatory initiatives intended to address seismic activity in Oklahoma and elsewhere could increase our costs of compliance or lead to operational delays, which could have a material adverse effect on our business, results of operations or financial condition. We dispose of large volumes of water produced alongside oil and natural gas “produced water” in connection with our drilling and production operations, pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued under existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic events in certain areas, including Oklahoma and Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting and operating of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma has taken numerous regulatory actions in response to concerns related to the operation of produced water disposal wells and induced seismicity. Oklahoma has adopted a "traffic light" system, wherein the Oklahoma Corporation Commission (OCC) reviews new or existing disposal wells for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. In September 2014, the OCC adopted rules for operators of produced water disposal wells in certain seismically-active areas, or Areas of Interest, requiring operators to monitor and record well pressure and injected volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of produced water to conduct more frequent mechanical integrity testing. On March 25, 2015, the Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) issued a directive, expanding the Areas of Interest for induced seismicity. Under the new directive, operators of 347 disposal wells located within the expanded Areas of Interest of the Arbuckle formation were given until April 2015 to demonstrate that their wells were not disposing into or in communication with the crystalline basement rock. Operators of wells in contact or communication with the basement rock were required to reduce the depth of, or "plug back," those wells or, alternatively, to reduce disposal volume by 50 percent. On July 17, 2015, the OGCD issued another directive, further expanding the covered area to include an additional 211 disposal wells. Under this second directive, operators were given until August 2015 to prove that they were not injecting below the Arbuckle formation or, as necessary, to plug back those wells in contact or communication with the crystalline basement rock, without the option of reducing disposal volume by 50 percent. The OGCD imposed further reductions on oil and natural gas wastewater disposal well volume in a prescribed area of northern Oklahoma County and southern Logan County in August 2015, requiring operators to reduce disposal volumes for affected wells by approximately 38 percent below 2014 reported volumes, within a specified 60-day period. OGCD imposed additional restrictions on wells in Fairview County in January 2016, requiring that all disposal wells located within 3.5 miles of a seismic event's epicenter reduce injection volumes by 50 percent and 25 percent for wells within 10 miles of the event's epicenter. The OGCD has also begun imposing additional testing requirements on wells located within 15 miles of an event's epicenter. Additional regulatory action in this area is likely, and the Oklahoma legislature has introduced new legislation to expand the OCC's authority to address concerns related to disposal wells and induced seismicity. Furthermore, following increased seismic activity in February 2016, the OGCD released a wastewater volume reduction plan. The plan calls for the operators of over 240 injection wells to reduce underground wastewater injections. The plan covers more than 5,200 square miles in northwest Oklahoma, which is near our operations, and seeks reductions of more than 500,000 barrels of wastewater per day. Implementation of the plan will be phased in during 2016. Additionally, in recent years there has been increased public concern regarding an alleged potential for hydraulic fracturing to induce seismic events, among other allegations. For example, in July 2016, the OCC announced an investigation of all oil and gas activity, not solely injection or disposal wells, in the Blanchard, Oklahoma area in response to recent seismic activity there.

In Texas, in 2014, the Texas Railroad Commission (TRC) published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

Restriction on the volumes permissible for injection or a lack of alternative waste disposal sites, or curtailment or restrictions on oil and gas activity generally, could cause us to delay, curb or discontinue our exploration and development plans. Increased costs associated with restrictions on hydraulic fracturing or the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal or hydraulic fracturing, such as mandated produced water recycling in some portion or all of our operations or prohibitions on performing hydraulic fracturing in certain areas, may reduce our profitability. These developments may result in additional levels of regulation, or increased complexity and costs with respect to existing regulations, that could lead to operational delays or increased operating and compliance costs, which could have a material adverse effect on our business, results of operations, cash flows or financial condition.

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, 2016.

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, 2016	237,718	$ 34.78	—	—
May 1 — May 31, 2016	3,420	36.04	—	—
June 1 — June 30, 2016	9,563	39.79	—	—
Total	250,701	$ 34.99	—	—

____

(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.

Item 6. Exhibits

Exhibit Number	Description
3.1	Fourth Amended and Restated Certificate of Incorporation of Newfield Exploration Company dated July 22, 2015 (incorporated by reference to Exhibit 3.1 to Newfield’s Current Report on Form 8-K filed with the SEC on July 27, 2015 (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))
†*10.1	First Amendment to the Newfield Exploration Company 2011 Omnibus Stock Plan, as Amended and Restated, effective April 12, 2016
†*10.2	Form of 2016 Restricted Stock Agreement for Non-Employee Directors under the Newfield Exploration Company 2011 Omnibus Stock Plan
†*10.3	Form of 2016 Restricted Stock Unit Award Agreement for Non-Employee Directors under the Newfield Exploration Company 2011 Omnibus Stock Plan and the Newfield Exploration Company Non-Employee Directors' Deferred Compensation Plan
*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.
† Identifies management contracts and compensatory plans or arrangements.

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: August 3, 2016 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	Fourth Amended and Restated Certificate of Incorporation of Newfield Exploration Company dated July 22, 2015 (incorporated by reference to Exhibit 3.1 to Newfield's Current Report on Form 8-K filed with the SEC on July 27, 2015 (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))
†*10.1	First Amendment to the Newfield Exploration Company 2011 Omnibus Stock Plan, as Amended and Restated, effective April 12, 2016
†*10.2	Form of 2016 Restricted Stock Agreement for Non-Employee Directors under the Newfield Exploration Company 2011 Omnibus Stock Plan
†*10.3	Form of 2016 Restricted Stock Unit Award Agreement for Non-Employee Directors under the Newfield Exploration Company 2011 Omnibus Stock Plan and the Newfield Exploration Company Non-Employee Directors' Deferred Compensation Plan
*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.
†Identifies management contracts and compensatory plans or arrangements.