NEWFIELD EXPLORATION CO /DE/
Form 10-Q
April 29, 2013

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 March 31, 2013

OR

o 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 o

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 o

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

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

As of April 22, 2013, there were 135,446,252 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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

	March 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 44	$ 88
Accounts receivable	408	452
Inventories	110	132
Derivative assets	51	125
Other current assets	59	69
Total current assets	672	866
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,566 and $1,485 were excluded from amortization at March 31, 2013 and December 31, 2012, respectively)	14,747	14,346
Less accumulated depreciation, depletion and amortization	(7,655)	(7,444)
Total property and equipment, net	7,092	6,902
Derivative assets	22	17
Long-term investments	61	58
Deferred taxes	39	24
Other assets	42	45
Total assets	$ 7,928	$ 7,912
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 60	$ 69
Accrued liabilities	767	801
Advances from joint owners	41	31
Asset retirement obligations	9	10
Derivative liabilities	39	6
Deferred taxes	4	42
Total current liabilities	920	959
Other liabilities	46	47
Derivative liabilities	24	15
Long-term debt	3,045	3,045
Asset retirement obligations	137	132
Deferred taxes	974	934
Total long-term liabilities	4,226	4,173
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, 200,000,000 shares authorized at March 31, 2013 and December 31, 2012; 136,566,889 and 136,530,907 shares issued at March 31, 2013 and December 31, 2012, respectively)		1			1	
Additional paid-in capital		1,528			1,522	
Treasury stock (at cost, 1,124,345 and 1,216,591 shares at March 31, 2013 and December 31, 2012, respectively)		(34	)		(36	)
Accumulated other comprehensive loss		(5	)		(7	)
Retained earnings		1,292			1,300	
Total stockholders' equity		2,782			2,780	
Total liabilities and stockholders' equity	$	7,928		$	7,912	

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

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Oil, gas and NGL revenues	$ 651	$ 678
Operating expenses:		
Lease operating	123	127
Production and other taxes	115	83
Depreciation, depletion and amortization	222	226
General and administrative	46	45
Total operating expenses	506	481
Income from operations	145	197
Other income (expense):		
Interest expense	(51)	(51)
Capitalized interest	14	18
Commodity derivative income (expense)	(84)	24
Other	3	(1)
Total other income (expense)	(118)	(10)
Income before income taxes	27	187
Income tax provision (benefit):		
Current	48	48
Deferred	(13)	23
Total income tax provision (benefit)	35	71
Net income (loss)	$ (8)	$ 116
Earnings (loss) per share:		
Basic	$ (0.06)	$ 0.86
Diluted	$ (0.06)	$ 0.86
Weighted-average number of shares outstanding for basic earnings (loss) per share	135	134
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	135

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 March 31,	
	2013	2012
Net income (loss)	$ (8)	$ 116
Other comprehensive income:		
Unrealized gain on investments, net of tax	2	2
Other comprehensive income, net of tax	2	2
Comprehensive income (loss)	$ (6)	$ 118

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

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

	Three Months Ended March 31, 2013	2012
Cash flows from operating activities:		
Net income (loss)	$ (8)	$ 116
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	222	226
Deferred tax provision (benefit)	(13)	23
Stock-based compensation	9	8
Commodity derivative (income) expense	84	(24)
Cash receipts on derivative settlements, net	27	34
Other non-cash charges	2	4
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	60	(74)
(Increase) decrease in inventories	11	(12)
(Increase) decrease in other current assets	10	5
(Increase) decrease in other assets	2	(1)
Increase (decrease) in accounts payable and accrued liabilities	(55)	(67)
Increase (decrease) in advances from joint owners	10	(25)
Increase (decrease) in other liabilities	(2)	(1)
Net cash provided by operating activities	359	212
Cash flows from investing activities:		
Additions to oil and gas properties	(399)	(468)
Acquisitions of oil and gas properties	—	(9)
Proceeds from sales of oil and gas properties	4	312
Additions to other property and equipment	(4)	(3)
Net cash used in investing activities	(399)	(168)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	532	594
Repayments of borrowings under credit arrangements	(532)	(680)
Purchases of treasury stock, net	(4)	(7)
Net cash used in financing activities	(4)	(93)
Decrease in cash and cash equivalents	(44)	(49)
Cash and cash equivalents, beginning of period	88	76
Cash and cash equivalents, end of period	$ 44	$ 27

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

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2012	136.5	$ 1	(1.2)	$ (36)	$ 1,522	$ 1,300	$ (7)	$ 2,780
Issuances of common stock	0.1	—			—			—
Stock-based compensation					12			12
Treasury stock, net			0.1	2	(6)			(4)
Net loss						(8)		(8)
Other comprehensive income, net of tax							2	2
Balance, March 31, 2013	136.6	$ 1	(1.1)	$ (34)	$ 1,528	$ 1,292	$ (5)	$ 2,782

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

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids (NGLs). Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast. Internationally, we focus on offshore oil developments in Malaysia and China. In February 2013, we initiated a process to evaluate strategic alternatives with respect to our international businesses.

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

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

These consolidated financial statements and notes should be read in conjunction with our audited consolidated financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2012. The Company's general and administrative expenses for the three months ended March 31, 2013 were reduced by approximately $8 million due to a prior period adjustment related to our 2012 bonus accrual to reflect actual amounts approved and paid in the first quarter of 2013. The Company believes this correcting adjustment in the first quarter of 2013 is not material to its prior consolidated financial statements or its estimated annual results for the year.

Dependence on Commodity Prices

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 and access to capital and on the quantities of oil, natural gas and NGL reserves that we can economically produce.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil, natural gas and

NGL reserves. Actual results could differ significantly from these estimates. Our most significant financial estimates are associated with our estimated proved oil, natural gas and NGL reserves and the fair value of our derivative positions.

Investments

Investments consist primarily of debt and equity securities, as well as auction rate securities, a majority of which are classified as “available-for-sale” and stated at fair value. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component within the consolidated statement of comprehensive income. Realized gains or losses are computed based on specific identification of the securities sold. We regularly assess our investments for impairment and consider any impairment to be other than temporary if we intend to sell the security, it is more likely than not that we will be required to sell the security, or we do not expect to recover our cost of the security. We realized interest income and net gains on our investment securities of approximately $1 million for each of the three-month periods ended March 31, 2013 and 2012.

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

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 offshore operations in Malaysia and China. Inventories are carried at the lower of cost or market. Substantially all of the crude oil from our offshore operations in Malaysia and China is produced into floating production, storage and off-loading vessels (FPSOs) or onshore storage terminals and "lifted" and sold periodically as barge quantities are accumulated. The product inventory from our international operations consisted of approximately 455,000 barrels and 744,000 barrels of crude oil valued at cost of $42 million and $64 million at March 31, 2013 and December 31, 2012, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion expense.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $36 million and $31 million of internal costs during the three months ended March 31, 2013 and 2012, respectively. Interest expense related to unproved properties is also capitalized into oil and gas properties.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

Capitalized costs and estimated future development costs are amortized using a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. A particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using oil, natural gas and NGL reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior 12 months, adjusted for market differentials (SEC pricing), applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus

- the cost of properties not included in the costs being amortized, if any; less

- related income tax effects.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown reduces earnings and stockholders' equity in the period of occurrence and, holding other factors constant, results in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil, natural gas and NGL prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At March 31, 2013, the ceiling value of our reserves was calculated based upon SEC pricing of $2.95 per MMBtu for natural gas and $92.59 per barrel for oil. Using these prices, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective cost centers. As such, no ceiling test writedowns were required at March 31, 2013. If there are further declines in SEC pricing of oil and natural gas subsequent to March 31, 2013, we may be required to record a ceiling test writedown in future periods.

At December 31, 2012, the ceiling value of our reserves was calculated based upon SEC pricing of $2.76 per MMBtu for natural gas and $94.84 per barrel for oil. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by, and caused a writedown of, approximately $1.5 billion ($948 million, after-tax). The ceiling with respect to our properties in Malaysia and China exceeded the net capitalized costs of cost centers, requiring no writedown at December 31, 2012.

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

Other Property and Equipment

Furniture, fixtures and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. Gathering systems and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives of 25 years.

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the present value of the asset retirement cost in oil and gas properties in the period in which the ARO is incurred. Settlements include payments made to satisfy the AROs, as well as transfer of the ARO to purchasers of our divested properties.

In general, the amount of an ARO and the costs capitalized will equal the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the original capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statement of operations.

The change in our ARO for the three months ended March 31, 2013 is set forth below (in millions):

Balance at January 1, 2013	$ 142
Accretion expense	3
Additions	3
Revisions	1
Settlements	(3)
Balance at March 31, 2013	146
Less: Current portion of ARO at March 31, 2013	(9)
Total long-term ARO at March 31, 2013	$ 137

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Derivative Financial Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance, which requires that every derivative instrument be recorded on the consolidated balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. All of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price-risk management activities as accounting hedges under the accounting guidance and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings.

The related cash flow impact of our derivative activities is reflected as cash flows from operating activities. See Note 4, "Derivative Financial Instruments," for a more detailed discussion of our derivative activities.

Offsetting Assets and Liabilities

Our derivative financial instruments are subject to master netting arrangements and are reflected on our consolidated balance sheet accordingly. See Note 4, "Derivative Financial Instruments," for details regarding the gross amounts, as well as the impact of our netting arrangements on our net derivative position. We have only offset assets and liabilities in relation to our derivative financial instruments. We do not have any gross amounts that are subject to a master netting arrangement that are not offset in our consolidated balance sheet.

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

New Accounting Requirements

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance will require disclosure of gross information and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. Adoption of the additional disclosures about offsetting assets and liabilities did not have a material impact on our financial position or results of operations.

In February 2013, the FASB issued guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after December 15, 2012. Adoption of the new reporting guidance did not have a material impact on our financial position or results of operations as we did not have reclassifications during the periods presented.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted-average number of shares of common stock (excluding unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted stock and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. Please see Note 10, "Stock-Based Compensation."

The following is the calculation of basic and diluted weighted-average shares outstanding and EPS for the indicated periods:

	Three Months Ended March 31, 2013	2012
	(In millions, except per share data)	
Income (numerator):		
Net income (loss) — basic and diluted	$ (8)	$ 116
Weighted-average shares (denominator):		
Weighted-average shares — basic	135	134
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period(1)(2)	—	1
Weighted-average shares — diluted	135	135
Earnings (loss) per share:		
Basic	$ (0.06)	$ 0.86
Diluted	$ (0.06)	$ 0.86

(1)

The effect of stock options and unvested restricted stock and restricted stock units outstanding has not been included in the calculation of shares outstanding for diluted EPS for the quarter ended March 31, 2013, as their effect would have been anti-dilutive. Had we recognized net income for that quarter, incremental shares attributable to the assumed exercise of outstanding options and the assumed vesting of unvested restricted stock and restricted stock units would have increased diluted weighted-average shares outstanding by 0.6 million shares for the quarter.

(2) The calculation of shares outstanding for diluted EPS for the quarter ended March 31, 2012 excludes the effect of three million unvested restricted stock or restricted stock units and stock options because including the effect would be anti-dilutive.

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

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following:

	March 31, 2013	December 31, 2012
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 12,963	$ 12,647
Not subject to amortization	1,566	1,485
Gross oil and gas properties	14,529	14,132
Accumulated depreciation, depletion and amortization	(7,584)	(7,378)
Net oil and gas properties	6,945	6,754
Other property and equipment:		
Furniture, fixtures and equipment	142	141
Gathering systems and equipment	76	73
Accumulated depreciation and amortization	(71)	(66)
Net other property and equipment	147	148
Total property and equipment, net	$ 7,092	$ 6,902

The following is a summary of our oil and gas properties not subject to amortization as of March 31, 2013. We believe that our evaluation activities related to substantially all of our conventional properties not subject to amortization will be completed within four years. Because of the size of our unconventional resource plays, the entire evaluation will take significantly longer than four years. At March 31, 2013, approximately 84% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

	Costs Incurred In				
	2013	2012	2011	2010 and Prior	Total
	(In millions)				
Acquisition costs	$ 12	$ 135	$ 285	$ 435	$ 867
Exploration costs	215	156	20	47	438
Development costs	1	31	39	—	71
Fee mineral interests	—	—	—	23	23
Capitalized interest	14	68	77	8	167
Total oil and gas properties not subject to amortization	$ 242	$ 390	$ 421	$ 513	$ 1,566

Gulf of Mexico Asset Sale

In October 2012, we closed on the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for approximately $208 million, subject to customary post-closing adjustments. The sale of our remaining assets in the Gulf of Mexico did not significantly alter the relationship between capitalized costs and proved reserves and as such, all proceeds were recorded as adjustments to our domestic full cost pool with no gain or loss recognized. These consolidated financial statements include the results of our Gulf of Mexico operations through the date of sale.

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Other Asset Sales

During the three months ended March 31, 2013 and the year ended December 31, 2012, we sold certain oil and gas properties for proceeds of approximately $4 million and $630 million (includes Gulf of Mexico asset sale discussed above), respectively. The cash flows and results of operations for the assets included in a sale are included in our consolidated financial statements up to the date of sale. All of the proceeds associated with our asset sales were recorded as adjustments to our domestic full cost pool.

4. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize the following derivative strategies, which consist of either a single derivative instrument or a combination of instruments, to hedge against the variability in cash flows associated with the forecasted sale of our future oil and natural gas production:

- fixed-price swaps (swap). With respect to a swap position, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap strike price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap strike price;

- collars (combination of purchased put options (floor) and sold call options (ceiling)). For a collar position, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor strike price while we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor strike price and equal to or less than the ceiling strike price;

- fixed-price swaps with sold puts. A swap with a sold put position consists of a standard swap position plus a put sold by us with a strike price below the associated fixed-price swap. This structure enables us to increase the fixed-price swap with the value received through the sale of the additional put. If the settlement price for any settlement period falls equal to or below the additional put strike price, then we will only receive the difference between the swap price and the put strike price. If the settlement price is greater than the additional put strike price, the result is the same as it would have been with a standard swap only; and

- collars with sold puts. A collar with a sold put position consists of a standard collar position plus a put sold by us with a strike price below the floor strike price of the collar. This structure enables us to improve the collar strike prices with the value received through the sale of the additional put. If the settlement price for any settlement period falls equal to or below the additional put strike price, then we will receive the difference between the floor strike price and the additional put strike price. If the settlement price is greater than the additional put strike price, the result is the same as it would have been with a standard collar only.

While the use of these derivative instruments limits the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions "Derivative assets" and "Derivative liabilities." Substantially all of 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, in the case of collars and sold puts, the remaining term of options. The calculation of the fair value of collars and sold puts requires the use of an option-pricing model. Please see Note 7, "Fair Value Measurements." We recognize all realized and unrealized gains and losses related to these contracts on a mark-to-market basis in our consolidated statement of operations under the caption "Commodity derivative income (expense)." Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

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

At March 31, 2013, we had outstanding positions with respect to our future production that were not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu				
				Collars		Estimated
Period and Type of Instrument	Volume in MMMBtus	Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)	Fair Value Asset (Liability) (In millions)
2013:						
Fixed-price swaps	41,250	$4.08	—	—	—	$(2)
Collars	4,575	—	—	$3.75	$4.57	—
Collars with sold puts(A)	28,730	3.45	$4.02	5.39	6.32	11
2014:						
Fixed-price swaps	74,825	3.92	—	—	—	(23)
Collars	23,725	—	—	3.75	4.62	(2)
2015:						
Fixed-price swaps	32,850	4.26	—	—	—	(1)
Collars	16,425	—	—	3.83	4.91	—
Total						$(17)

(A) During the first quarter of 2012, natural gas spot market prices were below the puts we sold on our collar with sold put positions for April through December 2012 and the full-year 2013, exposing us further to the softening natural gas spot market. As a result, during the first quarter of 2012, we entered into additional swap positions in the over-the-counter market that effectively prevented any further erosion in the value of our natural gas collar with sold put positions. The new swap positions added during the first quarter of 2012 were for the same volumes as our full-year 2013 collar with sold put positions. The economics from the combination of these additional swap positions and our natural gas collar with sold put positions will result in an effective average fixed price of $4.82 per MMBtu as long as natural gas spot prices for the respective time periods settle below the puts we sold on our collar with sold put positions. In the event natural gas spot prices settle above the ceilings on our associated collar with sold put position volumes, we would not recover the difference through the sale of our production as we would realize losses on both instruments discussed above.

Oil

		NYMEX Contract Price Per Bbl				
				Collars		Estimated
Period and Type of Instrument	Volume in MBbls	Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)	Fair Value Asset (Liability) (In millions)
2013:						

Fixed-price swaps	640	$88.61	—	—	—	$(6)
Fixed-price swaps with sold puts	2,750	97.49	$75.00	—	—	2
Collars with sold puts	6,817	—	80.00	$95.00	$114.81	15
2014:						
Fixed-price swaps	4,199	89.55	—	—	—	(13)
Collars with sold puts	5,110	—	80.00	95.00	119.16	28
2015:						
Fixed-price swaps	1,822	90.25	—	—	—	1
Total						$27

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Additional Disclosures about Derivative Instruments and Hedging Activities

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				Derivative Liabilities			
			Balance Sheet Location				Balance Sheet Location	
	Gross Fair Value	Offset in Balance Sheet	Current	Noncurrent	Gross Fair Value	Offset in Balance Sheet	Current	Noncurrent
March 31, 2013	(In millions)				(In millions)			
Natural gas positions	$ 47	$ (15)	$ 32	$ —	$ (64)	$ 15	$ (32)	$ (17)
Oil positions	46	(5)	19	22	(19)	5	(7)	(7)
Total	$ 93	$ (20)	$ 51	$ 22	$ (83)	$ 20	$ (39)	$ (24)
December 31, 2012								
Natural gas positions	$ 86	$ (5)	$ 79	$ 2	$ (16)	$ 5	$ (4)	$ (7)
Oil positions	77	(16)	46	15	(26)	16	(2)	(8)
Total	$ 163	$ (21)	$ 125	$ 17	$ (42)	$ 21	$ (6)	$ (15)

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

	Three Months Ended March 31,	
	2013	2012
	(In millions)	
Derivatives not designated as hedging instruments:		
Realized gain on natural gas positions	$27	$44
Realized loss on oil positions	—	(7)
Realized loss on basis positions	—	(3)
Total realized gain	27	34
Unrealized gain (loss) on natural gas positions	(88)	5
Unrealized loss on oil positions	(23)	(18)
Unrealized gain on basis positions	—	3
Total unrealized loss	(111)	(10)
Total	$(84)	$24

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty, and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty. At March 31, 2013, eight of our 15 counterparties accounted for approximately 85% of our estimated future hedged production, with no single counterparty accounting for more than 17% of that production.

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

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5. Accounts Receivable:

Accounts receivable consisted of the following:

	March 31, 2013	December 31, 2012
	(In millions)	
Revenue	$ 260	$ 291
Joint interest	140	154
Other	9	8
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$ 408	$ 452

6. Accrued Liabilities:

Accrued liabilities consisted of the following:

	March 31, 2013	December 31, 2012
	(In millions)	
Revenue payable	$ 97	$ 95
Accrued capital costs	363	355
Accrued lease operating expenses	74	95
Employee incentive expense	13	50
Accrued interest on debt	46	43
Taxes payable	141	108
Other	33	55
Total accrued liabilities	$ 767	$ 801

7. 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 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.

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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). Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our valuation methodology for investments is a discounted cash flow model that considers various inputs including: (a) the coupon rate specified under the debt instruments, (b) the current credit ratings of the underlying issuers, (c) collateral characteristics and (d) risk-adjusted discount rates. Level 3 instruments primarily include derivative instruments, such as commodity options (price collars and sold puts) and other financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques for derivative instruments, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

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 levels.

Fair Value of Investments and Derivative Instruments

The following table summarizes the valuation of our financial assets (liabilities) by measurement levels:

	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, 2012:				
Money market fund investments	$ 22	$ —	$ —	$ 22
Deferred compensation plan assets	6	—	—	6
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	36	36
Oil and gas derivative swap contracts	—	6	—	6
Oil and gas derivative option contracts	—	—	115	115
Total	$ 35	$ 6	$ 151	$ 192
As of March 31, 2013:				
Money market fund investments	$ 1	$ —	$ —	$ 1
Deferred compensation plan assets	7	—	—	7
Investments available-for-sale:				
Equity securities	6	—	—	6
Auction rate securities	—	—	39	39

Oil and gas derivative swap contracts	—	(60)	—	(60)
Oil and gas derivative option contracts	—	—	70	70
Total	$ 14	$ (60)	$ 109	$ 63

The determination of the fair values above incorporates various factors, which include the impact of our non-performance risk on our liabilities, 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.

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As of March 31, 2013, we held $39 million of auction rate securities maturing beginning in 2033 that are classified as a Level 3 fair value measurement. This amount reflects a decrease in the fair value of these investments since the time of purchase of $6 million ($4 million net of tax) recorded under the caption “Accumulated other comprehensive loss” on our consolidated balance sheet. As of December 31, 2012, we held $36 million of auction rate securities, which reflected a decrease in the fair value of $9 million ($6 million net of tax) since the date of purchase. The debt instruments underlying our auction rate securities are mostly investment grade (rated BBB or better) and are guaranteed by the United States government or backed by private loan collateral. We do not believe the decrease in the fair value of these securities is permanent because we currently intend to hold these investments until the auction succeeds, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

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

	Investments	Derivatives	Total
		(In millions)	
Balance at January 1, 2012	$32	$71	$103
Total realized or unrealized gains (losses):			
Included in earnings	—	(12)	(12)
Included in other comprehensive income (loss)	2	—	2
Purchases, issuances and settlements:			
Settlements	—	(19)	(19)
Transfers in and out of Level 3	—	—	—
Balance at March 31, 2012	$34	$40	$74
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at March 31, 2012	$—	$(13)	$(13)
Balance at January 1, 2013	$36	$115	$151
Total realized or unrealized gains (losses):			
Included in earnings	—	(27)	(27)
Included in other comprehensive income (loss)	3	—	3
Purchases, issuances and settlements:			
Settlements	—	(18)	(18)
Transfers in and out of Level 3	—	—	—
Balance at March 31, 2013	$39	$70	$109
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at March 31, 2013	$—	$(5)	$(5)

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Commodity Derivatives. Our valuation models for level 3 derivative contracts are primarily industry-standard models that consider various factors, including certain significant unobservable inputs such as (a) quoted forward prices for commodities, (b) volatility factors and (c) counterparty credit risk. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the strike prices fixed by the hedge agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. 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 leads 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.

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

Auction Rate Securities. We utilize a discounted cash flow model in the determination of the valuation of our auction rate securities classified as Level 3. This model considers various inputs including (a) the coupon rate specified under the debt instrument, (b) the current credit rating of the underlying issuers, (c) collateral characteristics and (d) risk-adjusted discount rates. The most significant unobservable factor in the determination of the investments fair value, however, is market liquidity for these instruments. A significant change in the liquidity of the market for auction rate securities would lead to a corresponding change in the fair value measurement of these investments.

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	$ 43	Option model	NYMEX oil price forward curve	$ 91.51	-	$ 97.64
			Oil price volatility curves	16.16 %	-	24.25 %
			Credit risk	0.01 %	-	1.93 %
Natural gas option contracts	$ 27	Option model	NYMEX natural gas price forward curve	$ 3.92	-	$ 4.54
			Natural gas price volatility curves	21.32 %	-	31.95 %
			Credit risk	0.01 %	-	2.80 %

The underlying inputs in the determination of the valuation of our auction rate securities are developed by a third party and, therefore, not included in the quantitative analysis above.

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:

	March 31, 2013	December 31, 2012
	(In millions)	
5¾% Senior Notes due 2022	$ 806	$ 836

5 % Senior Notes due 2024	1,031	1,074
7 % Senior Subordinated Notes due 2018	624	630
6 % Senior Subordinated Notes due 2020	751	749

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8. Debt:

As of the indicated dates, our debt consisted of the following:

	March 31, 2013	December 31, 2012
	(In millions)	
Senior unsecured debt:		
5¾% Senior Notes due 2022	$ 750	$ 750
5 % Senior Notes due 2024	1,000	1,000
Total senior unsecured debt	1,750	1,750
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	700	700
Discount on notes	(5)	(5)
Total long-term debt	$ 3,045	$ 3,045

Credit Arrangements

We have a revolving credit facility that matures in June 2016. The terms of the credit facility provide for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, N.A., as agent. In September 2011, we entered into the first amendment to the credit facility, which allows us to issue senior notes or other debt instruments that are secured equally and ratably with the credit facility. As of March 31, 2013, the largest individual loan commitment by any lender was 13% of total commitments.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank, N.A. or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points, plus a margin that is based on a grid of our debt rating (75 basis points per annum at March 31, 2013) or (b) the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (175 basis points per annum at March 31, 2013).

Under our credit facility, we pay commitment fees on available but undrawn amounts based on a grid of our debt rating (30 basis points per annum at March 31, 2013). We incurred aggregate commitment fees under our current credit facility of approximately $1 million for each of the three-month periods ended March 31, 2013 and 2012, which are recorded in “Interest expense” on our consolidated statement of operations.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns and goodwill impairments) to interest expense of at least 3.0 to 1.0. At March 31, 2013, we were in compliance with all of our debt covenants.

As of March 31, 2013, we had no letters of credit outstanding under our credit facility. Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at March 31, 2013). Additionally, as of March 31, 2013, we had $2 million of other undrawn letters of credit outstanding.

Subject to compliance with the restrictive covenants in our credit facility, at March 31, 2013, we also had a total of $195 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

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

9. Income Taxes:

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(In millions)	
Amount computed using the statutory rate	$ 9	$ 65
Increase (decrease) in taxes resulting from:		
State and local income taxes, net of federal effect	1	2
Net effect of different tax rates in non-U.S. jurisdictions	1	4
U.S. tax on international earnings	24	—
Foreign tax credit	(13)	—
Valuation allowance	13	—
Total provision for income taxes	$ 35	$ 71

The effective tax rates for the first three months of 2013 and 2012 were 128.8% and 37.8%, respectively. Historically, our effective tax rate was approximately 37%. However, the effective tax rate for March 31, 2013, was affected by our fourth quarter 2012 decision to repatriate earnings from our foreign operations. The U.S. tax on international earnings, the foreign tax credit and the valuation allowance are a result of the decision to repatriate international earnings into our domestic operations.

As of March 31, 2013, we did not have a liability for uncertain tax positions and as such we had not accrued related interest or penalties. The tax years 2009-2012 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

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10. Stock-Based Compensation:

All stock-based compensation equity awards to employees and non-employee directors are currently granted under the 2011 Omnibus Stock Plan (our 2011 Plan). The fair value of grants is determined utilizing the Black-Scholes option-pricing model for stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units. In February 2011 and February 2013, we also granted cash-settled restricted stock units to a limited number of employees. These awards were not issued under any of our plans as they will be settled in cash upon vesting and are accounted for as liability awards.

As of the dates indicated, our stock-based compensation consisted of the following:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(In millions)	
Total stock-based compensation	$ 12	$ 12
Capitalized in oil and gas properties	(3)	(4)
Net stock-based compensation expense	$ 9	$ 8

As of March 31, 2013, we had approximately $116 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting periods. The full amount is expected to be recognized within four years.

Stock Options. The following table provides information about stock option activity for the three months ended March 31, 2013:

	Number of Shares Underlying Options (In thousands)	Weighted-Average Exercise Price per Share	Weighted-Average Grant Date Fair Value per Share	Weighted-Average Remaining Contractual Life (In years)	Aggregate Intrinsic Value(1) (In millions)
Outstanding at December 31, 2012	901	$38.06		3.3	$1
Granted	—	—	$—		
Exercised	(35)	17.28			1
Forfeited	(10)	45.98			
Outstanding at March 31, 2013	856	$38.80		3.1	$—
Exercisable at March 31, 2013	856	$38.80		3.1	$—

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

On March 31, 2013, the last reported sales price of our common stock on the New York Stock Exchange was $22.42 per share.

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Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity for the three months ended March 31, 2013:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted-Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at December 31, 2012	2,371	438	2,809	$ 43.31
Granted	1,368	300	1,668	28.76
Forfeited	(153)	—	(153)	38.56
Vested	(402)	—	(402)	41.63
Non-vested shares outstanding at March 31, 2013	3,184	738	3,922	$ 37.48

Cash-Settled Restricted Stock Units. During the first quarter of 2011 and during the first quarter of 2013, we granted cash-settled restricted stock units to a limited number of employees that vest over three years. The value of the awards, and the associated stock-based compensation expense, is based on the Company's stock price. In February 2012, the first tranche of the 2011 grants vested, which required settlement of approximately 44,000 cash-settled restricted units for approximately $1.7 million. In February 2013, the second tranche of the 2011 grants vested, which required settlement of approximately 38,000 cash-settled restricted units for approximately $1.1 million. As of March 31, 2013, we had approximately 234,000 cash-settled restricted stock units outstanding and unrecognized stock-based compensation expense of approximately $3.6 million for cash-settled restricted stock units.

Employee Stock Purchase Plan. During the first quarter of 2013, options to purchase approximately 108,000 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $6.90 per share. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 0.11%, an expected life of six months and weighted-average volatility of 40%.

11. Commitments and Contingencies:

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

12. Segment Information:

While we operate 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, Malaysia and China. The accounting policies of each of our operating segments are the same as those described in Note 1, “Organization and Summary of Significant Accounting Policies.”

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The following tables provide the geographic operating segment information for each of the three-month periods ended March 31, 2013 and 2012. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

	Domestic	Malaysia	China	Total
		(In millions)		
Three Months Ended March 31, 2013:				
Oil, gas and NGL revenues	$370	$258	$23	$651
Operating expenses:				
Lease operating	88	34	1	123
Production and other taxes	12	100	3	115
Depreciation, depletion and amortization	147	69	6	222
General and administrative	45	1	—	46
Allocated income tax	29	21	3	
Net income from oil and gas properties	$49	$33	$10	
Total operating expenses				506
Income from operations				145
Interest expense, net of interest income, capitalized interest and other				(34)
Commodity derivative expense				(84)
Income before income taxes				$27
Total assets	$6,760	$777	$391	$7,928
Additions to long-lived assets	$346	$40	$33	$419

	Domestic	Malaysia	China	Total
		(In millions)		
Three Months Ended March 31, 2012:				
Oil, gas and NGL revenues	$402	$249	$27	$678
Operating expenses:				
Lease operating	102	23	2	127
Production and other taxes	21	55	7	83
Depreciation, depletion and amortization	166	54	6	226
General and administrative	44	1	—	45
Allocated income tax	25	44	3	
Net income from oil and gas properties	$44	$72	$9	
Total operating expenses				481
Income from operations				197
Interest expense, net of interest income, capitalized interest and other				(34)
Commodity derivative income				24
Income before income taxes				$187
Total assets	$7,898	$870	$269	$9,037

Additions to long-lived assets	$489	$32	$16	$537

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13. Supplemental Cash Flows Information:

The following table presents information about supplemental cash flows:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(In millions)	
Non-cash items excluded from the statement of cash flows:		
Increase in accrued capital expenditures	$ (8)	$ (43)
(Increase) decrease in asset retirement costs	(4)	4

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

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast. Internationally, we focus on offshore oil developments in Malaysia and China. In February 2013, we initiated a process to evaluate strategic alternatives with respect to our international businesses and expect to open a data room in the second quarter of 2013.

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

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital; and
- the quantity of oil, natural gas and NGLs that we can economically produce.

We prepare our financial statements in conformity with generally accepted accounting principles in the United States of America, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and natural gas reserves. In addition, we use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these assets, are capitalized. The net capitalized costs for our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves. If these costs exceed the limit, we are required to charge the excess to earnings, also referred to as a "ceiling test writedown". As of December 31, 2012, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by, and caused a writedown of, approximately $1.5 billion ($948 million, after-tax). At March 31, 2013, using SEC pricing of $2.95 per MMBtu for natural gas and $92.59 per barrel of oil, adjusted for market differentials, the present value of our estimated future net cash flows from proved reserves exceeded the net capitalized costs for our oil and gas properties. Therefore, we did not have a ceiling test writedown as of March 31, 2013. The risk of incurring a ceiling test writedown increases when commodity prices are low for a sustained period of time. If there are further declines in SEC pricing of oil and natural gas subsequent to March 31, 2013, we may be required to record a ceiling test writedown in future periods.

Results of Operations

Revenues. Our revenues are primarily from the sale of oil, natural gas and NGLs and do not include the effects of settlements of our derivative positions. Please see Note 4, "Derivative Financial Instruments," to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold. In addition, substantially all of the crude oil from our offshore operations in Malaysia and China is produced into FPSOs or onshore storage terminals, and "lifted" and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into FPSOs or onshore storage terminals. As a result, the timing of liftings may impact period-to-period results.

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Revenues of $651 million for the first quarter of 2013 were 4% lower than the comparable period of 2012 primarily due to declines in oil prices and lower levels of natural gas production. Crude oil production was up 4% in the first quarter of 2013 compared to the first quarter of 2012. Consistent with our continued focus on increasing our liquids production, we did not invest in natural gas production and allowed it to decline. Increased NGL production for the first quarter of 2013 was partially offset by a 34% decline in realized NGL prices compared to the same period of 2012. The following table reflects our production and average realized commodity prices for the following periods:

	Three Months Ended March 31,		Percentage Increase (Decrease)
	2013	2012	
Production:(1)(2)			
Domestic:			
Crude oil and condensate (MBbls)	2,964	3,018	(2)%
Natural gas (Bcf)	28.4	38.3	(26)%
NGLs (MBbls)	1,018	579	76%
Total (MBOE)	8,712	9,983	(13)%
International:			
Crude oil and condensate (MBbls)	2,548	2,306	11%
Natural gas (Bcf)	0.2	0.2	19%
Total (MBOE)	2,588	2,339	11%
Total:			
Crude oil and condensate (MBbls)	5,512	5,324	4%
Natural gas (Bcf)	28.6	38.5	(26)%
NGLs (MBbls)	1,018	579	76%
Total (MBOE)	11,300	12,322	(8)%
Average Realized Prices:(2)(3)			
Domestic:			
Crude oil and condensate (per Bbl)	$83.90	$91.22	(8)%
Natural gas (per Mcf)	3.14	2.63	19%
NGLs (per Bbl)	28.63	43.19	(34)%
Crude oil equivalent (per BOE)	42.12	40.17	5%
International:			
Crude oil and condensate (per Bbl)	$110.02	$119.17	(8)%
Natural gas (per Mcf)	3.79	4.33	(12)%
Crude oil equivalent (per BOE)	108.69	117.85	(8)%
Total:			
Crude oil and condensate (per Bbl)	$95.98	$103.33	(7)%
Natural gas (per Mcf)	3.14	2.64	19%
NGLs (per Bbl)	28.63	43.19	(34)%
Crude oil equivalent (per BOE)	57.36	54.92	4%

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in operations of 2.6 Bcf and 2.2 Bcf during the first three months of 2013 and 2012, respectively.

(2) Historically, we reported NGL volumes combined with crude oil and condensate production. In our Form 10-K for period ended December 31, 2012, we began reporting NGL production separately from crude oil and condensate production. As such, all production volumes and average realized prices for the three months ended March 31, 2012 have been recalculated for comparability between periods.

(3)

Had we included the effects of hedging contracts not designated for hedge accounting, the average realized price for total natural gas would have been $4.09 and $3.70 per Mcf for the three months ended March 31, 2013 and 2012, respectively; and the average crude oil realized price would have been $96.06 and $102.01 per Bbl for the three months ended March 31, 2013 and 2012, respectively. We did not have any hedging contracts associated with NGL production during the three months ended March 31, 2013 or 2012.

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Domestic Production. Our first quarter 2013 domestic total production, stated on a BOE basis, decreased compared to first quarter 2012 production. Approximately 73% of the decrease relates to the sale of our Gulf of Mexico assets during the fourth quarter of 2012. Excluding the effect of the sale of our Gulf of Mexico assets, consistent with our expectations, total production decreased. The decrease in overall production was accompanied by a change in our product mix whereby higher margin oil growth of 11%, adjusted for the sale of our Gulf of Mexico assets, was offset by the decrease in natural gas production of 20%. The decrease in natural gas production was due to natural decline as a result of the lack of investment in natural gas wells. Excluding the effect of the sale of our Gulf of Mexico assets, our domestic liquids production increased approximately 27% in the first quarter of 2013, compared to the first quarter of 2012. NGL production comprised approximately two-thirds of the increase in liquids production for the first quarter 2013.

International Production. Our first quarter 2013 international total production, stated on a BOE basis, increased 11% over the comparable period of 2012, primarily due to new production in our East Belumut and East Piatu fields in Malaysia. The new production was brought online as wells were completed, primarily during the second and third quarters of 2012.

Operating Expenses.

The following table presents information about our operating expenses between the following periods:

	Unit-of-Production Three Months Ended March 31,		Percentage Increase (Decrease)	Total Amount Three Months Ended March 31,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$ 10.04	$ 10.25	(2)%	$ 88	$ 102	(15)%
Production and other taxes	1.39	2.08	(33)%	12	21	(42)%
Depreciation, depletion and amortization	16.91	16.65	2 %	147	166	(11)%
General and administrative	5.17	4.47	16 %	45	44	1 %
Total operating expenses	33.51	33.44	—	292	333	(13)%
International:						
Lease operating	$ 13.66	$ 10.58	29 %	$ 35	$ 25	43 %
Production and other taxes	39.69	26.68	49 %	103	62	65 %
Depreciation, depletion and amortization	28.85	25.78	12 %	75	60	24 %
General and administrative	0.34	0.21	62 %	1	1	84 %
Total operating expenses	82.55	63.24	31 %	214	148	44 %
Total:						
Lease operating	$ 10.87	$ 10.31	5 %	$ 123	$ 127	(3)%
Production and other taxes	10.16	6.75	51 %	115	83	38 %
Depreciation, depletion and amortization	19.64	18.38	7 %	222	226	(2)%
General and administrative	4.06	3.66	11 %	46	45	2 %
Total operating expenses	44.74	39.10	14 %	506	481	5 %

Domestic Operations. Our domestic operating expenses for the three months ended March 31, 2013, stated on a per BOE basis, were flat over the same period of 2012. The primary offsetting components within our domestic operating expenses are as follows:

- Production and other taxes per BOE decreased 33% primarily due to production tax credits received during the first quarter of 2013 in our Rocky Mountains region.

- General and administrative (G&A) expense per BOE increased 16%, primarily due to employee-related expenses associated with our domestic work force combined with lower domestic production. During the first quarter of 2013, we capitalized $28 million ($3.23 per BOE) of direct internal costs as compared to $24 million ($2.37 per BOE) during the first quarter of 2012.

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International Operations. Our international operating expenses for the three months ended March 31, 2013, stated on a per BOE basis, increased 31% over the same period of 2012. The components of the period-to-period change are as follows:

- Lease operating expenses (LOE) include normally recurring expenses to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. LOE per BOE increased 29% ($3.08 per BOE) due to higher fees associated with producing into onshore storage terminals in Malaysia. The increases in Malaysia were partially offset by decreases in China as non-recurring well workover activity was minimal during the first quarter of 2013, when compared to the first quarter of 2012.

- Production and other taxes per BOE increased by 49% due to the terms of our production sharing contracts in Malaysia, which stipulate significant increases in production taxes subsequent to reaching certain cost recovery milestones. We expect the elevated production tax rates to continue as the majority of our fields in Malaysia are currently subject to these higher rates.

- Total depreciation, depletion and amortization (DD&A) expense increased 24% due to a combination of an increase in the average DD&A rate and an 11% increase in production during the first quarter of 2013 as compared to the first quarter of 2012. Our average quarterly DD&A rate per BOE increased 12% when compared to the quarterly rate for the comparative period in 2012. The increase was primarily due to the costs of two unsuccessful exploratory wells in offshore Malaysia in the fourth quarter of 2012, which increased the amount subject to depletion in the first quarter of 2013 without a corresponding increase in reserves.

Interest Expense. The following table presents information about interest expense for the indicated periods:

	Three Months Ended March 31,	
	2013	2012
	(In millions)	
Gross interest expense:		
Credit arrangements	$ 2	$ 2
Senior notes	25	11
Senior subordinated notes	24	38
Total gross interest expense	51	51
Capitalized interest	(14)	(18)
Net interest expense	$ 37	$ 33

Interest expense associated with unproved oil and gas properties is capitalized into oil and gas properties. Capitalized interest decreased $4 million for the first quarter of 2013 as compared to the first quarter of 2012, due to a reduction in our average balance of unproved oil and gas properties.

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

Taxes. The effective tax rates for the first three months of 2013 and 2012 were 128.8% and 37.8%, respectively. Historically, our effective tax rate was approximately 37%. However, the effective tax rate for March 31, 2013, was affected by our fourth quarter 2012 decision to repatriate earnings from our foreign operations as discussed in Note 9, “Income Taxes,” to our consolidated financial statements appearing earlier in this report.

Estimates of future taxable income can be significantly affected by changes in oil, natural gas and NGL prices; the timing, amount and location of future production; operating expenses; and capital costs.

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Liquidity and Capital Resources

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

We establish a capital budget for each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, which includes cash flows from operations and if applicable, non-strategic asset sales, as well as available borrowing capacity under our credit arrangements. Approximately 84% of our expected 2013 domestic oil and gas production (excluding NGLs) is hedged. Our 2013 capital budget, excluding estimated capitalized interest and overhead of $182 million, is expected to be between $1.7 and $1.9 billion and focuses on projects with higher rates of return, which we believe will generate and lay the foundation for oil production growth in 2014 and thereafter. Of the total 2013 capital budget, approximately $1.4 to $1.5 billion will be allocated to our domestic business. Substantially all of the 2013 capital budget is allocated to oil or liquids-rich projects.

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; the extent to which properties are acquired or non-strategic assets sold. We believe we have the operational flexibility to react to changes in circumstances and our cash flows from operations.

We expect to fund our 2013 capital program with cash flows from operations, available borrowing capacity under our credit arrangements and proceeds from non-strategic asset sales during the year. We believe that the Company's liquidity position and our ability to generate cash flows from our asset portfolio will be adequate to fund 2013 operations.

Credit Arrangements. We maintain a revolving credit facility of $1.25 billion that matures in June 2016, as well as money market lines of credit of $195 million, for a total borrowing capacity of $1.45 billion at March 31, 2013. Our long-term debt includes senior and senior subordinated notes, which total $3.05 billion. At March 31, 2013, we had no scheduled maturities of senior notes or senior subordinated notes until 2018. For a more detailed description of the terms of our credit arrangements and senior and senior subordinated notes, please see Note 8, "Debt," to our consolidated financial statements appearing earlier in this report.

As of April 22, 2013, our available borrowing capacity under our credit arrangements was approximately $1.3 billion, and we had the following:

- no borrowings under our credit facility;
- $70 million of letters of credit outstanding under our credit facility;
- outstanding borrowings of $80 million under our money market lines of credit; and
- $2 million in other undrawn letters of credit outstanding.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. We anticipate that our 2013 capital investment levels will exceed our estimate of cash flows from operations. We expect to use available capacity under our credit arrangements and proceeds from non-strategic asset sales to fund any shortfall.

At March 31, 2013, we had negative working capital of $248 million compared to negative working capital of $93 million at December 31, 2012. The changes in our working capital are primarily a result of the timing of the collection of receivables, changes in the fair value of our derivative positions, the timing of crude oil liftings in our international operations, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Cash flows from operations are our primary source of capital and liquidity and are primarily affected by the sale of our oil, natural gas and NGLs, as well as commodity prices, net of the effects of derivative contract settlements and changes in working capital. We sell substantially all of our oil, natural gas and NGLs under floating price, market sensitive contracts. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 24-36 months. As of March 31, 2013, we had no open derivative contracts for NGLs. See "—Oil and Gas Hedging" below.

We typically receive the cash associated with oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations are impacted by changes in working capital and are not affected by DD&A, ceiling test writedowns, other impairments or other non-cash charges or credits.

Our net cash flows from operations were $359 million for the three months ended March 31, 2013, an increase of $147 million compared to net cash flows from operations of $212 million for the same period in 2012. Our working capital requirements change each year as a result of the timing of drilling activities, receivable collections from purchasers and joint interest partners, international crude oil inventory levels, payments made by us to vendors and other operators, the timing and amount of advances received from our joint operations and the change in net cash receipts on derivative settlements.

Cash Flows from Investing Activities. Net cash used in investing activities for the three months ended March 31, 2013 was $399 million compared to $168 million for the same period in 2012. During the three months ended March 31, 2013 and 2012, we spent approximately $403 million and $480 million for additions to property and equipment, respectively. During the three months ended March 31, 2013, we received proceeds of $4 million from sales of oil and gas properties as compared to proceeds of $312 million for the comparable period of 2012.

Cash Flows from Financing Activities. Net cash used in financing activities for the three months ended March 31, 2013 was $4 million compared to $93 million for the same period in 2012. During the three months ended March 31, 2013, our borrowings were offset by repayments of the same amount. During the three months ended March 31, 2012, we reduced our borrowings under our revolving credit facility by $86 million.

Capital Expenditures. Our capital investments of $411 million for the first quarter of 2013 decreased 21% from our capital investments of $523 million during the same period of 2012. These amounts exclude acquisitions and recorded asset retirement obligations, both of which were immaterial in the first quarter of 2013 and 2012. Of the total $411 million invested during the first quarter of 2013, we invested $288 million in domestic exploitation and development, $47 million in domestic exploration (exclusive of exploitation and leasehold activity), $3 million in leasing domestic proved and unproved property (leasehold) and $73 million outside the United States. Of the total $523 million spent during the first quarter of 2012, we invested $400 million in domestic exploitation and development, $48 million in domestic exploration (exclusive of exploitation and leasehold activity), $30 million in leasing domestic proved and unproved property (leasehold) and $45 million outside the United States.

We have budgeted between $1.7 and $1.9 billion for our planned capital investments in 2013. The planned budget excludes capitalized interest and overhead of $182 million, as well as acquisitions. Substantially all of the 2013 budget is allocated to liquids-rich projects. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, commodity prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, at times we have increased our capital budget as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

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.

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Contractual Obligations

We have various contractual obligations in the normal course of our operations. There have been no material changes with respect to our contractual obligations subsequent to December 31, 2012. For further information, please 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, 2012.

Oil and Gas Hedging

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 24-36 months. As of March 31, 2013, we had no outstanding derivative contracts related to our NGL production. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes.

Please see the discussion and tables in Note 4, "Derivative Financial Instruments," and Note 7, "Fair Value Measurements," to our consolidated financial statements appearing earlier in this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open positions and the estimated fair market value of those positions as of March 31, 2013.

Between April 1, 2013 and April 22, 2013, we entered into additional derivative contracts as set forth below.

Natural Gas

		NYMEX Contract Price Per MMBtu			
				Collars	
Period and Type of Instrument	Volume in MMMBtus	Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)
2015:					
Collars	21,900	—	—	$ 4.00	$ 4.62

Accounting for Hedging Activities. We do not designate future price-risk management activities as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience non-cash volatility in our reported earnings during periods of commodity price volatility. As of March 31, 2013, we had net derivative assets of $10 million, of which 41%, based on total hedged volumes, was measured based upon our valuation model (i.e. Black-Scholes) and, as such, is classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. As a result, the value of these contracts at their respective settlement dates could be significantly different than the fair value as of March 31, 2013. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please 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, 2012 and Note 4, "Derivative Financial Instruments," and Note 7, "Fair Value Measurements," to our consolidated financial statements appearing earlier in this report for additional discussion of the accounting applicable to our oil and gas derivative contracts.

New Accounting Requirements

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance will require disclosure of gross information and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. Adoption of the additional disclosures about offsetting assets and liabilities did not have a material impact on our financial position or results of operations.

In February 2013, the FASB issued guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after December 15, 2012. Adoption of the new reporting guidance did not have a material impact on our financial position or results of operations as we did not have reclassifications during the periods presented.

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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. All statements, other than statements of historical facts included in this report, are forward-looking, including information relating to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures and other plans and objectives for future operations. Forward-looking statements are typically identified by use of terms such as “may,” “believe,” “expect,” “anticipate,” “intend,” “estimate,” “project,” “target,” “goal,” “plan,” “sho “predict,” “potential” and similar expressions that convey the uncertainty of future events or outcomes. Although we believe that these expectations are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

- oil, natural gas and NGL prices and demand;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing and climate change;
- land, legal and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- the availability and volatility of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, hedging 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;
- our commodity hedging arrangements as compared to actual commodity prices;
- the volatility in the commodity futures market;
- the availability of storage, transportation and refining capacity for the crude oil we produce in the Uinta Basin;
- drilling risks and results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- labor conditions;

- weather conditions;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- competitive conditions;
- terrorism or civil or political unrest in a region or country;
- our ability to monetize non-strategic assets, pay debt and the impact of changes in our investment ratings;
- electronic, cyber or physical security breaches;
- changes in tax rates;
- inflation rates;
- uncertainties and changes in estimates of reserves;

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- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities; and
- the additional factors discussed elsewhere in our public filings and press releases, including the factors discussed in "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" included in our 2012 Annual Report on Form 10-K.

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

Commonly Used Oil and Gas Terms

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

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

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

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

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

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

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

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

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

NYMEX. The New York Mercantile Exchange.

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

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

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

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

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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 hedge our production is based in part on our view of current and future market conditions. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions 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 March 31, 2013, eight of our 15 counterparties accounted for approximately 85% of our estimated future hedged production with no single counterparty accounting for more than 17% of that production. For a further discussion of our hedging activities, see the information under the caption “Oil and Gas Hedging” in Item 2 appearing earlier in this report and the discussion and tables in Note 4, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report.

Interest Rates

We consider our interest rate exposure to be minimal because 100% of our obligations were at fixed rates as of March 31, 2013. A 10% increase in LIBOR would not impact our interest cost on debt outstanding as of March 31, 2013, but would affect the fair value of our outstanding debt, as well as interest costs associated with future debt issuances or borrowings under our revolving credit facility.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country’s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at March 31, 2013.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2013.

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 first quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based upon that evaluation, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. Legal Proceedings

In August 2010, we received a Notice of Violation (NOV) from the Environmental Protection Agency (EPA) alleging that we failed to provide adequate financial assurance for water injection wells falling under EPA jurisdiction that are located at our Monument Butte field in Duchesne County, Utah (Monument Butte). The injection wells are part of an enhanced oil recovery project designed to optimize production from Monument Butte. Regulations under the Safe Drinking Water Act (SDWA) require operators of injection wells to file proof of financial assurance annually to cover the costs to plug and abandon the injection wells. The NOV alleges that our 2010 and 2009 filings (for 2009 and 2008) did not meet the financial ratio tests that are acceptable as one form of required financial assurance under SDWA regulations. The NOV was completely administrative in nature and did not contain any allegations of environmental spills, releases or pollution. Upon receipt of the NOV, we promptly complied with the EPA's request to put in place alternate financial assurance for the wells even though we in fact believed we did meet the financial ratio tests. We held preliminary discussions with the EPA regarding potential settlement of this matter; however, the EPA determined that the NOV could not be resolved within the EPA's settlement authority under the SDWA and required a referral to the Department of Justice (DOJ). We intend to vigorously defend against the DOJ's allegations. Although the outcome of this matter cannot be predicted with certainty, we do not expect it to have a material adverse effect on our financial position, cash flows or results of operations.

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

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors previously reported in our Annual Report on Form 10-K for the year ended December 31, 2012.

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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 March 31, 2013.

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
January 1 January 31, 2013	2,303	$ 26.23	—	—
February 1 February 28, 2013	116,583	29.26	—	—
March 1 March 31, 2013	2,239	23.06	—	—
Total	121,125	$ 29.09	—	—

(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.

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Item 6. Exhibits

Exhibit Number	Description
3.1	Third Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 1-12534))
3.2	Amended and Restated Bylaws of Newfield (incorporated by reference to Exhibit 3.2 to Newfield's Current Report on Form 8-K filed with the SEC on February 6, 2009 (File No. 1-12534))
*10.1	Form of Executive Officer Restricted Stock Unit Award Agreement under 2011 Omnibus Stock Plan
*10.2	Form of 2013 Executive Officer TSR Restricted Stock Unit Award Agreement under 2011 Omnibus Stock Plan
*31.1	Certification of Chief Executive Officer of Newfield 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 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 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 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 herewith.

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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: April 29, 2013	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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