NEWFIELD EXPLORATION CO /DE/
Form 10-Q
April 26, 2012

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, 2012

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 23, 2012, there were 134,808,094 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, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$27	$76
Accounts receivable	481	407
Inventories	110	90
Derivative assets	148	129
Other current assets	68	73
Total current assets	834	775
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,835 and $1,965 were excluded from amortization at March 31, 2012 and December 31, 2011, respectively)	14,736	14,526
Less accumulated depreciation, depletion and amortization	(6,737)	(6,506)
Total property and equipment, net	7,999	8,020
Derivative assets	60	61
Long-term investments	55	52
Deferred taxes	35	28
Other assets	54	55
Total assets	$9,037	$8,991
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$70	$112
Accrued liabilities	706	687
Advances from joint owners	20	45
Asset retirement obligations	10	10
Derivative liabilities	60	50
Deferred taxes	31	28
Total current liabilities	897	932
Other liabilities	44	44
Derivative liabilities	22	3
Long-term debt	2,920	3,006
Asset retirement obligations	134	135
Deferred taxes	978	951
Total long-term liabilities	4,098	4,139
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, 2012 and December 31, 2011; 136,396,431 and 136,379,381 shares issued at March 31, 2012 and December 31, 2011, respectively)	1	1
Additional paid-in capital	1,497	1,495
Treasury stock (at cost, 1,585,053 and 1,694,623 shares at March 31, 2012 and December 31, 2011, respectively)	(48)	(50)
Accumulated other comprehensive loss	(8)	(10)
Retained earnings	2,600	2,484
Total stockholders' equity	4,042	3,920
Total liabilities and stockholders' equity	$9,037	$8,991

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

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF NET INCOME
(In millions, except per share data)
(Unaudited)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Oil and gas revenues	$678	$545
Operating expenses:		
Lease operating	127	93
Production and other taxes	83	71
Depreciation, depletion and amortization	226	166
General and administrative	45	37
Total operating expenses	481	367
Income from operations	197	178
Other income (expenses):		
Interest expense	(51)	(40)
Capitalized interest	18	18
Commodity derivative income (expense)	24	(182)
Other	(1)	(1)
Total other income (expenses)	(10)	(205)
Income (loss) before income taxes	187	(27)
Income tax provision (benefit):		
Current	48	23
Deferred	23	(33)
Total income tax provision (benefit)	71	(10)
Net income (loss)	$116	$(17)
Earnings (loss) per share:		
Basic	$0.86	$(0.13)
Diluted	$0.86	$(0.13)
Weighted-average number of shares outstanding for basic earnings (loss) per share	134	133
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	133

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

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Net income (loss)	$116	$(17)
Other comprehensive income:		
Unrealized gain on investments, net of tax	2	3
Other comprehensive income, net of tax	2	3
Comprehensive income (loss)	$118	$(14)

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, 2012	Three Months Ended March 31, 2011
Cash flows from operating activities:		
Net income (loss)	$116	$(17)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	226	166
Deferred tax provision (benefit)	23	(33)
Stock-based compensation	8	6
Commodity derivative (income) expense	(24)	182
Cash receipts on derivative settlements, net	34	55
Other non-cash charges	4	2
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(74)	21
Increase in inventories	(12)	(12)
(Increase) decrease in other current assets	5	(10)
Increase in other assets	(1)	(3)
Decrease in accounts payable and accrued liabilities	(67)	(37)
Decrease in advances from joint owners	(25)	(10)
Decrease in other liabilities	(1)	(1)
Net cash provided by operating activities	212	309
Cash flows from investing activities:		
Additions to oil and gas properties	(468)	(466)
Acquisitions of oil and gas properties	(9)	—
Proceeds from sales of oil and gas properties	312	62
Additions to furniture, fixtures and equipment	(3)	(3)
Net cash used in investing activities	(168)	(407)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	594	670
Repayments of borrowings under credit arrangements	(680)	(546)
Proceeds from issuances of common stock	—	7
Purchases of treasury stock, net	(7)	(16)
Net cash provided by (used in) financing activities	(93)	115
Increase (decrease) in cash and cash equivalents	(49)	17
Cash and cash equivalents, beginning of period	76	39
Cash and cash equivalents, end of period	$27	$56

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	Retained	Accumulated Other Comprehensive Income	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Earnings	(Loss)	Equity
Balance, December 31, 2011	136.4	$ 1	(1.7)	$ (50)	$ 1,495	$ 2,484	$ (10)	$ 3,920
Stock-based compensation					11			11
Treasury stock, net			0.1	2	(9)			(7)
Net income						116		116
Other comprehensive income, net of tax							2	2
Balance, March 31, 2012	136.4	$ 1	(1.6)	$ (48)	$ 1,497	$ 2,600	$ (8)	$ 4,042

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

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

Our 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” or “our” 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 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, 2011.

Dependence on Oil and Natural Gas 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 and natural gas. Historically, the energy markets have been very volatile, and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil or natural gas 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 and natural gas 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 and gas reserves. Actual results could differ significantly from these estimates. Our most significant financial estimates are associated with our estimated proved oil and natural gas 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, 2012 and 2011.

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Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Substantially all of the crude oil from our operations offshore Malaysia and China is produced into FPSOs and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 578,000 barrels and 239,000 barrels of crude oil valued at cost of $38 million and $19 million at March 31, 2012 and December 31, 2011, 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 $31 million and $24 million of internal costs during the three months ended March 31, 2012 and 2011, 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 on 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 and natural gas reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus
- the lower of cost or estimated fair value 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 properties increases when oil and natural gas prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At March 31, 2012, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $3.73 per MMBtu for natural gas and $98.25 per barrel for oil, adjusted for market differentials. 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 properties. As such, no ceiling test writedowns were required at March 31, 2012.

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 the transfer of the ARO to purchasers of our divested properties.

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In general, the amount of an ARO and the costs capitalized will be equal to 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 additional 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 net income.

The change in our ARO for the three months ended March 31, 2012 is set forth below (in millions):

Balance as of January 1, 2012	$	145
Accretion expense		3
Additions		3
Settlements		(7)
Balance at March 31, 2012		144
Less: Current portion of ARO at March 31, 2012		(10)
Total long-term ARO at March 31, 2012	$	134

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 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. We also have utilized derivatives to manage our exposure to variable interest rates.

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

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

New Accounting Requirements

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change requires us, for Level 3 fair value measurements, to disclose quantitative information about unobservable inputs used, a description of the valuation processes used, and a qualitative discussion about the sensitivity of the measurements. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. Adopting the additional fair value measurement and disclosure requirements did not have a material impact on our financial position or results of operations.

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. We do not expect adoption of the additional disclosures regarding offsetting assets and liabilities to have a material impact on our financial position or results of operations.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (loss) (the numerator) by the weighted-average number of shares of common stock (other than 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,	
	2012	2011
	(In millions, except per share data)	
Income (numerator):		
Net income (loss) — basic and diluted	$ 116	$ (17)
Weighted-average shares (denominator):		
Weighted-average shares — basic	134	133
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	133
Earnings (loss) per share:		

Basic earnings (loss) per share	$	0.86	$	(0.13)
Diluted earnings (loss) per share	$	0.86	$	(0.13)

(1) The calculation of shares outstanding for diluted EPS for the three months ended March 31, 2012 does not include the effect of three million unvested restricted stock or restricted stock units and stock options because to do so would be anti-dilutive.

(2) 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 three months ended March 31, 2011 as their effect would have been anti-dilutive. Had we recognized net income for that period, 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 two million shares.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	March 31, 2012	December 31, 2011
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 12,760	$ 12,423
Not subject to amortization	1,835	1,965
Gross oil and gas properties	14,595	14,388
Accumulated depreciation, depletion and amortization	(6,664)	(6,436)
Net oil and gas properties	7,931	7,952
Other property and equipment	141	138
Accumulated depreciation and amortization	(73)	(70)
Net other property and equipment	68	68
Total property and equipment, net	$ 7,999	$ 8,020

The following is a summary of our oil and gas properties not subject to amortization as of March 31, 2012. 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, their entire evaluation will take significantly longer than four years. At March 31, 2012, approximately 75% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

	Costs Incurred In				
	2012	2011	2010	2009 and prior	Total
			(In millions)		
Acquisition costs	$42	$314	$312	$431	$1,099
Exploration costs	175	138	24	35	372
Development costs	14	70	25	37	146
Fee mineral interests	—	—	—	23	23
Capitalized interest	18	78	55	44	195
Total oil and gas properties not subject to amortization	$249	$600	$416	$570	$1,835

Non-Strategic Asset Sales

During the three months ended March 31, 2012 and the year ended December 31, 2011, we sold certain non-strategic assets for approximately $312 million and $434 million, 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.

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4. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize swap, floor, collar and three-way collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap 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 price. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and 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 price and equal to or less than the ceiling price. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

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, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors 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 net income 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)

At March 31, 2012, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu							
					Collars				Estimated Fair Value Asset
	Volume in	Swaps (Weighted	Additional Put	Weighted	Floors	Weighted	Ceilings	Weighted	
Period and Type of Contract	MMMBtus	Average)	Range	Average	Range	Average	Range	Average	(Liability) (In millions)
April 2012 – June 2012									
Price swap contracts	10,010	$4.17	—	—	—	—	—	—	$ 10
Price swap contracts	(A)	2.67	—	—	—	—	—	—	21
3-Way collar contracts	22,750	—	$3.50-$4.50	$4.30	$5.00-$5.75	$5.44	$5.20-$7.00	$6.26	26
July 2012 – September 2012									
Price swap contracts	10,120	4.17	—	—	—	—	—	—	7
Price swap contracts	(A)	2.67	—	—	—	—	—	—	15
3-Way collar contracts	23,000	—	3.50-4.50	4.30	5.00-5.75	5.44	5.20-7.00	6.26	26
October 2012 – December 2012									
Price swap contracts	11,340	3.19	—	—	—	—	—	—	1
Price swap contracts	(A)	2.72	—	—	—	—	—	—	2
3-Way collar contracts	15,070	—	3.50-4.50	4.19	5.00-6.00	5.51	5.20-7.55	6.41	18

January 2013 – December 2013									
Price swap contracts	54,750	4.08	—	—	—	—	—	—	19
Price swap contracts	(A)	3.45	—	—	—	—	—	—	14
3-Way collar contracts	39,530	—	3.50-4.50	4.04	5.00-6.00	5.44	6.00-7.55	6.48	43
January 2014 – December 2014									
Price swap contracts	40,150	3.89	—	—	—	—	—	—	(3)
									$ 199

(A) During the first quarter of 2012, natural gas spot market prices were below the puts we sold on our three-way collars 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 fixed-price swap contracts in the over-the-counter market that effectively prevented any further erosion in the value of our natural gas three-way collars. The new swap contracts added during the first quarter of 2012 were for the same volumes as our April through December 2012 and the full-year 2013 three-way collar contracts. The economics from the combination of these additional fixed-price swap contracts and our natural gas three-way collar contracts will result in effective average fixed prices of $3.81, $3.81, $4.04 and $4.85 per MMBtu for the second, third and fourth quarters of 2012 and the full-year 2013, respectively, as long as natural gas spot prices for the respective time periods remain below the puts we sold on our three-way collar contracts.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

Oil

		NYMEX Contract Price Per Bbl						Estimated Fair Value
				Collars				
		Additional Put		Floors		Ceilings		
Period and Type of Contract	Volume in MBbls	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Asset (Liability) (In millions)
April 2012 – June 2012								
3-Way collar contracts	3,185	$55.00-$90.00	$66.86	$75.00-$100.00	$82.96	$88.20-$137.80	$111.14	$ (11)
July 2012 – September 2012								
3-Way collar contracts	3,220	55.00-90.00	66.86	75.00-100.00	82.96	88.20-137.80	111.14	(18)
October 2012 – December 2012								
3-Way collar contracts	3,220	55.00-90.00	66.86	75.00-100.00	82.96	88.20-137.80	111.14	(22)
January 2013 – December 2013								
3-Way collar contracts	10,349	55.00-80.00	68.54	80.00-95.00	88.12	109.50-130.40	119.09	(13)
January 2014 – December 2014								
3-Way collar contracts	2,920	80.00	80.00	95.00	95.00	120.00-120.75	120.19	(2)
								$ (66)

Basis Contracts

At March 31, 2012, we had natural gas basis contracts that are not designated for hedge accounting to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points in the Rocky Mountains and Mid-Continent, as set forth in the table below.

	Rocky Mountains		Mid-Continent		Estimated Fair Value Asset (Liability)
	Volume in MMMBtus	Weighted-Average Differential	Volume in MMMBtus	Weighted-Average Differential	(In millions)
April 2012 – June 2012	1,230	$ (0.91)	4,550	$ (0.55)	$ (2)
July 2012 – September 2012	1,230	(0.91)	4,600	(0.55)	(3)
October 2012 – December 2012	1,230	(0.91)	4,600	(0.55)	(2)
					$ (7)

Additional Disclosures about Derivative Instruments and Hedging Activities

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

Type of Contract	Balance Sheet Location	March 31, 2012	December 31, 2011
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Derivative assets – current	$ 150	$ 133
Oil contracts	Derivative assets – current	1	1
Basis contracts	Derivative assets – current	(3)	(5)
Natural gas contracts	Derivative assets – noncurrent	51	61
Oil contracts	Derivative assets – noncurrent	9	—
Oil contracts	Derivative liabilities – current	(56)	(45)
Basis contracts	Derivative liabilities – current	(4)	(5)
Natural gas contracts	Derivative liabilities – noncurrent	(2)	—
Oil contracts	Derivative liabilities – noncurrent	(20)	(3)
Total		$ 126	$ 137

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

The amount of gain (loss) recognized in income related to our derivative financial instruments was as follows:

Type of Contract	Location of Gain (Loss) Recognized in Income	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
		(In millions)	
Derivatives not designated as hedging instruments:			
Realized gain on natural gas contracts	Commodity derivative income (expense)	$ 44	$ 68
Realized loss on oil contracts	Commodity derivative income (expense)	(7)	(12)
Realized loss on basis contracts	Commodity derivative income (expense)	(3)	(1)
Total realized gain		34	55
Unrealized gain (loss) on natural gas contracts	Commodity derivative income (expense)	5	(54)
Unrealized loss on oil contracts	Commodity derivative income (expense)	(18)	(183)
Unrealized gain on basis contracts	Commodity derivative income (expense)	3	—
Total unrealized loss		(10)	(237)
Total		$ 24	$ (182)

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, 2012, Bank of Montreal, Barclays Bank PLC, J Aron & Company, JPMorgan Chase Bank, N.A., Macquarie Bank Limited, and Morgan Stanley Capital Group Inc. were the counterparties with respect to approximately 85% of our estimated future hedged production, the largest of which was J Aron & Company and accounted for 26% of our estimated future hedged production.

The counterparties to the majority of our derivative instruments also are 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.

5. Accounts Receivable:

As of the indicated dates, our accounts receivable consisted of the following:

	March 31, 2012	December 31, 2011
	(In millions)	

Revenue	$ 369	$ 301
Joint interest	103	96
Other	10	11
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$ 481	$ 407

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6. Accrued Liabilities:

As of the indicated dates, our accrued liabilities consisted of the following:

	March 31, 2012	December 31, 2011
	(In millions)	
Revenue payable	$ 90	$ 94
Accrued capital costs	274	231
Accrued lease operating expenses	80	86
Employee incentive expense	26	61
Accrued interest on debt	65	52
Taxes payable	146	122
Other	25	41
Total accrued liabilities	$ 706	$ 687

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 price swaps and certain investments.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). 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 basis swaps, commodity options including, price collars, floors and three-way collars (as of March 31, 2012, our options were comprised of only three-way collars) and some 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.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

Fair Value of Investments and Derivative Instruments

The following tables summarize the valuation of our investments and financial instrument assets (liabilities) by pricing 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, 2011:				
Investments available-for-sale:				
Equity securities	$ 10	$ —	$ —	$ 10
Auction rate securities	—	—	32	32
Oil and gas derivative swap and basis contracts	—	66	(10)	56
Oil and gas derivative option contracts	—	—	81	81
Total	$ 10	$ 66	$ 103	$ 179
As of March 31, 2012:				
Money market fund investments	$ 8	$ —	$ —	$ 8
Investments available-for-sale:				
Equity securities	11	—	—	11
Auction rate securities	—	—	34	34
Oil and gas derivative swap and basis contracts	—	86	(7)	79
Oil and gas derivative option contracts	—	—	47	47
Total	$ 19	$ 86	$ 74	$ 179

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

As of March 31, 2012, we continued to hold $34 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 of $11 million ($7 million net of tax), recorded under the caption “Accumulated other comprehensive loss” on our consolidated balance sheet. As of December 31, 2011, we held $32 million of auction rate securities, which reflected a decrease in the fair value of $13 million ($8 million net of tax). 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.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

The following tables set 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 (In millions)	Total
Balance at January 1, 2011	$ 30	$ 48	$ 78
Total realized or unrealized gains (losses):			
Included in earnings	—	(123)	(123)
Included in other comprehensive income	4	—	4
Purchases, issuances and settlements:			
Settlements	—	(14)	(14)
Transfers in and out of Level 3	—	—	—
Balance at March 31, 2011	$ 34	$ (89)	$ (55)
Change in unrealized losses included in earnings relating to investments and derivatives still held at March 31, 2011	$ —	$ (124)	$ (124)
Balance at January 1, 2012	$ 32	$ 71	$ 103
Total realized or unrealized gains (losses):			
Included in earnings	—	(12)	(12)
Included in other comprehensive income	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 losses included in earnings relating to investments and derivatives still held at March 31, 2012	$ —	$ (13)	$ (13)

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Commodity Derivatives. Our valuation models for 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 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.

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.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

Quantitative Disclosures about Unobservable Inputs

Instrument Type	Estimated Fair Value Asset (Liability) (In millions)	Valuation Technique	Unobservable Input	Range		
		Quantitative Information about Level 3 Fair Value Measurements				
Basis contracts	$ (7)	Discounted cash flow	NYMEX Natural gas price forward curve	$ 2.13	-	$ 4.26
			Physical pricing point forward curves	$ 1.84	-	$ 3.01
			Credit risk	0.02 %	-	15.39 %
Oil 3-way collar contracts	$ (66)	Option model	NYMEX Oil price forward curve	$ 97.46	-	$ 105.61
			Oil price volatility curves	21.43 %	-	34.84 %
			Credit risk	0.02 %	-	15.39 %
Natural gas 3-way collar contracts	$ 113	Option model	NYMEX Natural gas price forward curve	$ 2.13	-	$ 4.26
			Natural gas price volatility curves	23.97 %	-	54.87 %
			Credit risk	0.02 %	-	15.39 %

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, 2012	December 31, 2011
	(In millions)	
5¾% Senior Notes due 2022	$ 786	$ 808
6 % Senior Subordinated Notes due 2014	330	329
6 % Senior Subordinated Notes due 2016	562	568
7 % Senior Subordinated Notes due 2018	636	635
6 % Senior Subordinated Notes due 2020	733	745

Amounts outstanding under our credit arrangements at March 31, 2012 and December 31, 2011 are stated at cost, which approximates fair value. Please see Note 8, “Debt.”

8. Debt:

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

	March 31, 2012	December 31, 2011
	(In millions)	
Senior unsecured debt:		
Revolving credit facility LIBOR based loans	$ —	$ 85
Money market lines of credit(1)	—	1
Total credit arrangements	—	86
5¾% Senior Notes due 2022	750	750
Total senior unsecured debt	750	836
6 % Senior Subordinated Notes due 2014	325	325
6 % Senior Subordinated Notes due 2016	550	550
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	695	695
Total long-term debt	$ 2,920	$ 3,006

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

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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, 2012, 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, 2012) 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, 2012).

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, 2012). We incurred aggregate commitment fees under our current and previous credit facilities of approximately $1 million and $0.5 million for each of the three-month periods ended March 31, 2012 and 2011, respectively, which are recorded in interest expense on our consolidated statement of net income.

Our credit facility has restrictive 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, 2012, we were in compliance with all of our debt covenants.

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, 2012). As of March 31, 2012, we had no letters of credit outstanding under our credit facility.

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $185 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.

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.

Senior and Senior Subordinated Notes

In September 2011, we sold $750 million of 5¾% Senior Notes due 2022 and received proceeds of $742 million (net of discount and offering costs). These notes were issued at 99.956% of par to yield 5¾%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

On March 30, 2012, we notified the bondholders that we will call all of our outstanding 6 % Senior Subordinated Notes due 2014 on April 30, 2012 at 101.1042% of the principal amount plus accrued interest. The outstanding principal balance of $325 million will be funded primarily through the use of our revolving credit facility, and as such, the notes remain classified as a long-term liability at March 31, 2012.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

9. Income Taxes:

The provision (benefit) 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,	
	2012	2011
	(In millions)	
Amount computed using the statutory rate	$ 65	$ (9)
Increase (decrease) in taxes resulting from:		
State and local income taxes, net of federal effect	2	(2)
Net effect of different tax rates in non-U.S. jurisdictions	4	1
Total provision (benefit) for income taxes	$ 71	$ (10)

As of March 31, 2012, we did not have a liability for uncertain tax positions and as such we had not accrued related interest or penalties. The tax years 2008-2011 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

10. Stock-Based Compensation:

On May 5, 2011, at our 2011 Annual Meeting of Stockholders, our stockholders approved the Newfield Exploration Company 2011 Omnibus Stock Plan (the 2011 Omnibus Stock Plan), and our 2009 Omnibus Stock Plan and 2009 Non-Employee Director Restricted Stock Plan were terminated such that no new grants will be made under the previous plans. Currently, all stock-based compensation equity awards to employees and non-employee directors are granted under the 2011 Omnibus Stock Plan. Outstanding awards under our previous stock plans were not impacted by the termination of such plans. 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, we also granted cash-settled restricted stock units to employees that 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 indicated dates, our stock-based compensation consisted of the following:

	Three Months Ended March 31,	
	2012	2011
	(In millions)	
Total stock-based compensation	$ 12	$ 8
Capitalized in oil and gas properties	(4)	(2)
Net stock-based compensation expense	$ 8	$ 6

As of March 31, 2012, we had approximately $114 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 five years.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

Stock Options. The following table provides information about stock option activity for the three months ended March 31, 2012:

	Number of Shares Underlying Options (In millions)	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, 2011	1.1	$36.31		4.0	$7
Granted	—	—	$—		
Exercised	—	—			—
Forfeited	—	—			
Outstanding at March 31, 2012	1.1	$36.78		3.8	$4
Exercisable at March 31, 2012	1.0	$35.83		3.7	$4

(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, 2012, the last reported sales price of our common stock on the New York Stock Exchange was $34.68 per share.

Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity for the three months ended March 31, 2012:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted-Average Grant Date Fair Value per Share
	(In millions, except per share data)			
Non-vested shares outstanding at December 31, 2011	2.2	0.3	2.5	$49.52
Granted	1.1	0.2	1.3	36.93
Forfeited	(0.1)	—	(0.1)	51.82
Vested	(0.5)	(0.1)	(0.6)	38.65
Non-vested shares outstanding at March 31, 2012	2.7	0.4	3.1	$46.20

Cash-Settled Restricted Stock Units. During the first quarter of 2011, we granted cash-settled restricted stock units to employees that vest over three years. The value of the awards, and the associated stock-based compensation expense, is based on the Company's stock price. 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. As of March 31, 2012, approximately 84,000 cash-settled restricted units were outstanding.

Employee Stock Purchase Plan. Pursuant to our employee stock purchase plan, for each six month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period.

During the first quarter of 2012, options to purchase approximately 72,000 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $11.61 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 0.06%, an expected life of six months and weighted-average volatility of 55%.

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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 (1) claims from royalty owners for disputed royalty payments, (2) commercial disputes, (3) personal injury claims and (4) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

12. Segment Information:

While we only have operations in the oil and gas exploration and production industry, we are organizationally structured along geographic operating segments. Our current operating segments are the United States, 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."

The following tables provide the geographic operating segment information for each of the three-month periods ended March 31, 2012 and 2011. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

Three Months Ended March 31, 2012:

	Domestic	Malaysia	China	Total
		(In millions)		
Oil and gas 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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Three Months Ended March 31, 2011:	Domestic	Malaysia	China	Total
		(In millions)		
Oil and gas revenues	$ 394	$ 134	$ 17	$ 545
Operating expenses:				
Lease operating	77	15	1	93
Production and other taxes	15	51	5	71
Depreciation, depletion and amortization	137	25	4	166
General and administrative	36	1	—	37
Allocated income tax	47	16	2	
Net income from oil and gas properties	$ 82	$ 26	$ 5	
Total operating expenses				367
Income from operations				178
Interest expense, net of interest income, capitalized interest and other				(23)
Commodity derivative expense				(182)
Loss before income taxes				$ (27)
Total assets	$ 6,821	$ 685	$ 210	$ 7,716
Additions to long-lived assets	$ 438	$ 42	$ 10	$ 490

13. Supplemental Cash Flows Information:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(In millions)	
Non-cash items excluded from the statement of cash flows:		
Increase in accrued capital expenditures	$(43)	$(3)
(Increase) decrease in asset retirement costs	4	(2)

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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 onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Prices for oil and natural gas 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 and gas that we can economically produce.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. The preparation of our financial statements in conformity with generally accepted accounting principles requires 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 gas reserves. We use the full cost method of accounting for our oil and gas activities.

Operational Highlights. Significant operational highlights during the first quarter of 2012 include the following:

- Production commenced in late 2011 from two offshore developments in Malaysia — East Piatu and Puteri. Malaysian production in the first quarter of 2012 increased 60% over the comparable period of 2011, primarily as a result of liftings associated with production from our recent developments brought online during 2011.
- Total production for the first quarter of 2012, including natural gas produced and consumed in operations, was 76 Bcfe, an increase of 6% over first quarter 2011 production volumes.
- Our oil and liquids liftings in the first quarter of 2012 were approximately 5.9 million barrels, or an average of approximately 65,000 BOPD, which is approximately 1,000 BOPD higher than the fourth quarter of 2011 and approximately 35% higher than the first quarter of 2011.
- We announced a long-term agreement (10 years) with a Utah crude oil refiner with expectations of adding 20,000 BOPD of refining capacity beginning in 2014. This is the second of two recent agreements that add 38,000 BOPD of future refining capacity.

Financial Highlights. Significant financial highlights during the first quarter of 2012 include the following:

- We had revenues of $678 million, 25% higher than the same period in 2011.
- We recorded net income of $116 million, or $0.86 per diluted share.
- We monetized $312 million through sales of non-strategic assets.

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Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production and do not include the effects of the settlements of our hedges. 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 operations offshore Malaysia and China is produced into FPSOs and "lifted" and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into the FPSO. As a result, the timing of liftings may impact period-to-period results.

Revenues of $678 million for the first quarter of 2012 were 25% higher than the comparable period of 2011 primarily due to higher oil production. The increase in average realized oil price during the first quarter of 2012 was offset by the decreases in average realized natural gas price and natural gas production as compared to the same period of 2011.

The following table summarizes production and average realized prices by product and by geographic area for the three-month periods ended March 31, 2012 and 2011.

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Percentage Increase (Decrease)
Production: (1)			
Domestic:			
Natural gas (Bcf)	38.3	43.6	(12) %
Oil, condensate and NGLs (MBbls)	3,597	2,873	25 %
Total (Bcfe)	59.9	60.8	(2) %
International:			
Natural gas (Bcf)	0.2	—	100 %
Oil, condensate and NGLs (MBbls)	2,306	1,492	55 %
Total (Bcfe)	14.0	9.0	57 %
Total:			
Natural gas (Bcf)	38.5	43.6	(12) %
Oil, condensate and NGLs (MBbls)	5,903	4,365	35 %
Total (Bcfe)	73.9	69.8	6 %
Average Realized Prices: (2)			
Domestic:			
Natural gas (per Mcf)	$ 2.63	$ 4.00	(34) %
Oil, condensate and NGLs (MBbls)	83.49	75.83	10 %
Natural gas equivalent (per Mcfe)	6.72	6.47	4 %
International:			
Natural gas (per Mcf)	$ 4.33	$ —	—
Oil, condensate and NGLs (MBbls)	119.17	101.22	18 %
Natural gas equivalent (per Mcfe)	19.64	16.87	16 %
Total:			
Natural gas (per Mcf)	$ 2.64	$ 4.00	(34) %
Oil, condensate and NGLs (MBbls)	97.43	84.51	15 %

Natural gas equivalent (per Mcfe)	9.18	7.81	18	%

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in our operations of 2.2 Bcfe and 1.7 Bcfe during the first quarters of 2012 and 2011, respectively.

(2) Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been \$3.70 and \$5.51 per Mcf for the three months ended March 31, 2012 and 2011, respectively. Our total oil and condensate average realized price would have been \$96.24 and \$81.86 per Bbl for the three months ended March 31, 2012 and 2011, respectively.

Domestic Production. Our first quarter 2012 domestic oil and gas production, stated on a natural gas equivalent basis, was slightly lower than the comparable period of 2011, primarily due to natural decline and maintenance-related shut-ins at several of our Gulf of Mexico and onshore conventional Gulf Coast natural gas assets, offset by increased oil production in our Rocky Mountain, onshore Gulf Coast and Mid-Continent divisions as a result of continued successful development drilling efforts.

International Production. Our first quarter 2012 international oil production increased 55% over the comparable period of 2011, primarily as a result of liftings associated with production from our recent developments brought online during 2011.

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Operating Expenses. We believe the most informative way to analyze changes in our operating expenses from period-to-period is on a unit-of-production, or per Mcfe, basis.

The following table presents information about our operating expenses for the three months ended March 31, 2012 and 2011.

	Unit-of-Production			Total Amount		
	Three Months Ended March 31,		Percentage Increase (Decrease)	Three Months Ended March 31,		Percentage Increase (Decrease)
	2012	2011		2012	2011	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$1.71	$1.26	36 %	$102	$77	33 %
Production and other taxes	0.35	0.25	40 %	21	15	35 %
Depreciation, depletion and amortization	2.77	2.26	23 %	166	137	21 %
General and administrative	0.74	0.60	23 %	44	36	23 %
Total operating expenses	5.57	4.37	27 %	333	265	26 %
International:						
Lease operating	$1.76	$1.89	(7)%	$25	$16	46 %
Production and other taxes	4.45	6.20	(28)%	62	56	12 %
Depreciation, depletion and amortization	4.30	3.18	35 %	60	29	111 %
General and administrative	0.04	0.08	(50)%	1	1	(24)%
Total operating expenses	10.54	11.35	(7)%	148	102	46 %
Total:						
Lease operating	$1.72	$1.34	28 %	$127	$93	36 %
Production and other taxes	1.12	1.02	10 %	83	71	17 %
Depreciation, depletion and amortization	3.06	2.37	29 %	226	166	37 %
General and administrative	0.61	0.53	15 %	45	37	22 %
Total operating expenses	6.52	5.26	24 %	481	367	31 %

Domestic Operations. Our domestic operating expenses for the three months ended March 31, 2012, stated on a Mcfe basis, increased 27% over the same period of 2011. The components of the period-to-period change are as follows:

- Lease operating expense (LOE) includes 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. Recurring LOE in our Rocky Mountain division accounted for 40% ($0.17 per Mcfe) of the increase due to overall operating and service-related costs in the areas in which we operate. Our onshore Gulf Coast and Rocky Mountain divisions and Gulf of Mexico operations experienced increased non-recurring repair-related expenses representing approximately 32% ($0.14 per Mcfe) of the increase in LOE. Transportation and general service-related costs in our other business units accounted for the remainder of the increase.

- Production and other taxes per Mcfe increased primarily due to a 35% decrease in production tax credits in our Mid-Continent and onshore Gulf Coast divisions, a 10% increase in realized oil prices and a slight increase in oil and natural gas production subject to production taxes. These increases were partially offset by a 34% decrease in realized natural gas prices.

- Since late 2009, the shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our depreciation, depletion and amortization (DD&A) rate, resulting in the increase in DD&A expense.

- General and administrative (G&A) expense per Mcfe increased primarily due to employee-related expenses associated with our growing domestic work force. We capitalized $24 million ($0.40 per Mcfe) and $18 million ($0.30 per Mcfe) of direct internal costs during the first quarters of 2012 and 2011, respectively.

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International Operations. Our international operating expenses for the three months ended March 31, 2012, stated on a Mcfe basis, decreased 7% as compared to the same period of 2011. The components of the period-to-period change are as follows:

- LOE per Mcfe decreased primarily due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia during the first quarter of 2012 resulting from new production from two developments (East Piatu and Puteri), which commenced production during the fourth quarter 2011.

- Production and other taxes per Mcfe decreased due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia during the first quarter of 2012 as stated above. In addition, the tax rate per barrel of oil lifted and sold from these developments is lower, per the terms of our PSCs, while we recover our costs associated with these developments. This decrease was partially offset by an increase in the average realized oil price during the first quarter of 2012.

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

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

	Three Months Ended March 31,	
	2012	2011
	(In millions)	
Gross interest expense:		
Credit arrangements	$ 2	$ 1
Senior notes	11	—
Senior subordinated notes	38	38
Other	—	1
Total gross interest expense	51	40
Capitalized interest	(18)	(18)
Net interest expense	$ 33	$ 22

The increase in gross interest expense for the three months ended March 31, 2012 as compared to the same period of 2011 primarily resulted from the September 2011 issuance of $750 million aggregate principal amount of 5¾% Senior Notes due 2022. See Note 8, "Debt," to our consolidated financial statements appearing earlier in this report. Interest expense related to unproved properties is capitalized into oil and gas properties.

Taxes. The effective tax rates for the first three months of 2012 and 2011 were 37.8% and 37.5%, respectively. Our effective tax rate generally approximates 37%. Our effective tax rate for all periods was different than the federal statutory tax rate due to deductions that do not generate tax benefits, state income taxes and the differences between international and U.S. federal statutory rates.

Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future 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 and natural gas may reduce the amount of oil and gas that we can economically produce, and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as further described below.

We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, primarily cash flows from operations. Approximately 90% of our expected 2012 domestic oil and gas production (excluding NGLs) supporting the current 2012 capital budget is hedged. Our 2012 capital budget, excluding capitalized interest and overhead of $210 million, is approximately $1.5 to $1.7 billion and focuses on projects with higher return on investment and which we believe generate and lay the foundation for oil production growth in 2012 and thereafter. Substantially all of the 2012 budget is allocated to oil or liquids-rich projects.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results, oil and natural gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year 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. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

During the first three months of 2012, we received proceeds from the sale of certain non-strategic assets of $312 million. We used the proceeds from these sales to eliminate borrowings outstanding under our credit arrangements, and as of March 31, 2012, we had the full $1.4 billion available under our credit arrangements. We continue to market other certain non-strategic assets. As a result, we expect to substantially fund our $1.5 to $1.7 billion 2012 capital program with cash flows from operations and the proceeds from non-strategic asset sales during the year. We believe that the Company's liquidity position, asset portfolio, and continued strong operating and financial performance provide the necessary financial flexibility to fund current operations.

Credit Arrangements. We have a revolving credit facility that matures in June 2016 and provides for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, N.A., as agent. As of March 31, 2012, the largest individual commitment by any lender was 13% of total commitments.

In addition, subject to compliance with the restrictive covenants in our credit facility, we also have a total of $185 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. For a more detailed description of the terms of our credit arrangements, please see Note 8, "Debt," to our consolidated financial statements appearing earlier in this report.

On March 30, 2012, we notified the bondholders that we will call all of our outstanding 6 % Senior Subordinated Notes due 2014 on April 30, 2012 at 101.1042% of the principal amount plus accrued interest. The outstanding principal balance of $325 million will be funded primarily through the use of our revolving credit facility, and as such, the notes remain classified as a long-term liability at March 31, 2012.

At April 23, 2012, we had no letters of credit or money market lines of credit outstanding under our credit arrangements and outstanding borrowings of $40 million under our credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.4 billion as of April 23, 2012 and will be $1.1 billion on a pro forma basis upon completion of the call of our 6 % Senior Subordinated Notes due 2014.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. Although we anticipate that our 2012 capital spending (excluding acquisitions) will correspond with our anticipated 2012 cash flows from operations and property sales proceeds, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At March 31, 2012, we had negative working capital of $63 million compared to negative working capital of $157 million at December 31, 2011. The changes in our working capital are primarily a result of the timing of the collection of receivables, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

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Cash Flows from Operations. Cash flows from operations are our primary source of capital and liquidity, and are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We sell substantially all of our oil and gas production 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 12-24 months. 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 $212 million for the three months ended March 31, 2012, a decrease of $97 million compared to net cash flows from operations of $309 million for the same period in 2011. Our working capital requirements change each period as a result of the timing of drilling activities, receivable collections from purchasers and joint interest partners, 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, 2012 was $168 million compared to $407 million for the same period in 2011.

During the three months ended March 31, 2012, we:

- spent $480 million, primarily for additions to oil and gas properties; and
- received proceeds of $312 million from sales of non-strategic oil and gas assets.

During the three months ended March 31, 2011, we:

- spent $469 million, primarily for additions to oil and gas properties; and
- received proceeds of $62 million from sales of non-strategic oil and gas assets.

Cash Flows from Financing Activities. Net cash flows used in financing activities for the three months ended March 31, 2012 were $93 million compared to net cash flows provided by financing activities of $115 million for the same period in 2011.

During the three months ended March 31, 2012, we:

- borrowed $594 million and repaid $680 million under our credit arrangements; and
- repurchased $7 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

During the three months ended March 31, 2011, we:

- borrowed $670 million and repaid $546 million under our credit arrangements;
- received proceeds of $7 million from the issuance of shares of our common stock upon the exercise of stock options; and

- repurchased $16 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

Capital Expenditures. Our capital investments of $523 million for the first quarter of 2012 increased 11% from our capital investments of $471 million during the same period of 2011. These amounts exclude acquisitions and asset retirement obligations, both of which were immaterial in 2012 and 2011. 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 proved and unproved property (leasehold) and domestic leasing activity and $45 million internationally. Of the $471 million spent during the first quarter of 2011, we invested $317 million in domestic exploitation and development, $66 million in domestic exploration (exclusive of exploitation and leasehold activity), $38 million in proved and unproved property (leasehold) and domestic leasing activity and $50 million internationally.

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We have budgeted $1.5 to $1.7 billion for capital spending in 2012. The planned budget excludes capitalized interest and overhead of $210 million and acquisitions. Substantially all of the 2012 budget is allocated to oil or liquids-rich projects. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and natural gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year 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.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. For further information, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Obligations" in our Annual Report on Form 10-K for the year ended December 31, 2011. In addition, in January 2012, we executed an agreement to provide 20,000 barrels of oil per day (approximately 7,300 MBbls per year) of refining capacity that spans a ten-year period with commitments commencing in January 2014.

Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and natural gas prices. 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. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions.

While the use of these 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 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 hedging arrangements with that counterparty. At March 31, 2012, Bank of Montreal, Barclays Bank PLC, J Aron & Company, JPMorgan Chase Bank, N.A., Macquarie Bank Limited, and Morgan Stanley Capital Group Inc. were the counterparties with respect to 85% of our estimated future hedged production, the largest of which was J Aron & Company and accounted for 26% of our estimated future hedged production.

A significant number of the counterparties to our hedging arrangements also are lenders under our credit facility. 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.

Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, a majority of our hedged oil and gas production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges.

The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.25-$0.50 per MMBtu less than the Henry Hub Index. Realized natural gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 90-95% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 4 Bcf of our natural gas production from April 2012 through December 2012 to lock in the differential at a weighted average of $0.91 per MMBtu less than the Henry Hub Index. In total, this hedge and the 8,000 MMBtus per day we have sold on a fixed physical basis for the same period, results in an average basis hedge of $0.91 per MMBtu less than the Henry Hub Index. In the Mid-Continent, we have hedged basis associated with approximately 13 Bcf of our anticipated natural gas production from the Stiles/Britt Ranch area for the period April 2012 through December 2012 at an average of $0.55 per MMBtu less than the Henry Hub Index.

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The price we receive for our Gulf Coast oil production, excluding NGLs, typically averages about 100-105% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains, excluding NGLs, is currently averaging about $16-$18 per barrel below the WTI price. Oil production from our Mid-Continent properties, excluding NGLs, typically averages 90-95% of the WTI price. Crude oil from our operations in Malaysia typically sells at a slight discount to Tapis, or about 110-115% of WTI. Crude oil from our operations in China typically sells at $10-$15 per barrel greater than the WTI price.

Please see the discussion and tables in Note 4, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report for a description of the accounting applicable to our hedging program, a listing of open contracts as of March 31, 2012 and the estimated fair market value of those contracts as of that date.

Between April 1, 2012 and April 23, 2012, we entered into additional natural gas derivative contracts as set forth below.

Period and Type of Contract	Volume in MMMBtus	NYMEX Contract Price Per MMBtu (Weighted Average)
January 2014 – December 2014		
Price swap contracts	14,600	$3.75

Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges 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, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of March 31, 2012, we had net derivative assets of $126 million, of which 32% 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, 2012. 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 and Note 4, “Derivative Financial Instruments,” and Note 7, “Fair Value Measurements,” to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Other Factors. Please see “Risk Factors” in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2011 for a discussion of other factors that affect our business, financial condition and results of operations. This report should be read together with those discussions.

New Accounting Requirements

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change requires us, for Level 3 fair value measurements, to disclose quantitative information about unobservable inputs used, a description of the valuation processes used, and a qualitative discussion about the sensitivity of the measurements. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. Adopting the additional fair value measurement and disclosure requirements did not have a material impact on our financial position or results of operations.

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. We do not expect adoption of the additional disclosures regarding offsetting assets and liabilities to have a material impact on our financial position or results of operations.

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Forward-Looking Information

This report contains information that is forward-looking or relates 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 information is typically identified by use of terms such as “may,” “believe,” “expect,” “anticipate,” “intend,” “estimate,” “project,” “target,” “goal,” “plan,” “should,” “will,” “predict,” “ 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 and natural gas prices and demand;
- operating hazards inherent in the exploration for and production of oil and gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations;
- the impact of regulatory approvals;
- the availability 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;
- the availability of 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;
- 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;
- uncertainties and changes in estimates of reserves;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources; and
- the additional factors discussed elsewhere in our other 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” are included in our 2011 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.

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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.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

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.

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

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

NYMEX. The New York Mercantile Exchange.

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

Proved reserves. Proved reserves are those quantities of oil and 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.

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 and natural gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and Natural Gas Prices

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and natural gas prices. 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. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. 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. For a further discussion of our hedging activities, see the information under the caption “Oil and Gas Hedging” in Item 2 of 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

At March 31, 2012, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
5¾% Senior Notes due 2022	$ 750	$ —
6 % Senior Subordinated Notes due 2014	325	—
6 % Senior Subordinated Notes due 2016	550	—
7 % Senior Subordinated Notes due 2018	600	—
6 % Senior Subordinated Notes due 2020	695	—
Total debt	$ 2,920	$ —

We consider our interest rate exposure to be minimal because 100% of our obligations were at fixed rates.

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, 2012.

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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 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 Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2012.

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 Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the first quarter of 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on 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 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, or 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.

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, 2011.

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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, 2012.

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, 2012	25,941	$ 38.26	—	—
February 1 - February 29, 2012	148,121	37.91	—	—
March 1 - March 31, 2012	2,042	35.99	—	—
Total	176,104	$ 37.94	—	—

(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 Executive Officer TSR Restricted Stock Unit Award Agreement Under 2011 Omnibus Stock Plan
†10.3	Summary of Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.14 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2011 (File No. 1-12534))
*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 or furnished herewith.
†   Identifies management contracts and compensatory plans or arrangements.

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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 26, 2012	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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Exhibit Index

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