NEWFIELD EXPLORATION CO /DE/
Form 10-Q
October 29, 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 September 30, 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 October 22, 2012, there were 135,223,639 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)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$125	$76
Accounts receivable	427	407
Inventories	125	90
Derivative assets	88	129
Other current assets	94	73
Total current assets	859	775
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($2,009 and $1,965 were excluded from amortization at September 30, 2012 and December 31, 2011, respectively)	15,617	14,526
Less accumulated depreciation, depletion and amortization	(7,211)	(6,506)
Total property and equipment, net	8,406	8,020
Derivative assets	22	61
Long-term investments	55	52
Deferred taxes	41	28
Other assets	48	55
Total assets	$9,431	$8,991
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$76	$112
Accrued liabilities	747	687
Advances from joint owners	27	45
Asset retirement obligations	6	10
Derivative liabilities	19	50
Deferred taxes	24	28
Total current liabilities	899	932
Other liabilities	42	44
Derivative liabilities	16	3
Long-term debt	3,190	3,006
Asset retirement obligations	143	135
Deferred taxes	973	951
Total long-term liabilities	4,364	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 September 30, 2012 and December 31, 2011; 136,501,207 and 136,379,381 shares issued at September 30, 2012 and December 31, 2011, respectively)	1	1
Additional paid-in capital	1,512	1,495
Treasury stock (at cost, 1,282,212 and 1,694,623 shares at September 30, 2012 and December 31, 2011, respectively)	(39)	(50)
Accumulated other comprehensive loss	(8)	(10)
Retained earnings	2,702	2,484
Total stockholders' equity	4,168	3,920
Total liabilities and stockholders' equity	$9,431	$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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Oil and gas revenues	$ 615	$ 628	$ 1,921	$ 1,794
Operating expenses:				
Lease operating	128	115	384	333
Production and other taxes	79	95	250	245
Depreciation, depletion and amortization	237	189	702	528
General and administrative	59	51	165	132
Other	6	—	6	—
Total operating expenses	509	450	1,507	1,238
Income from operations	106	178	414	556
Other income (expenses):				
Interest expense	(53)	(43)	(153)	(124)
Capitalized interest	17	24	53	61
Commodity derivative income (expense)	(98)	262	61	249
Other	(16)	3	(18)	2
Total other income (expenses)	(150)	246	(57)	188
Income (loss) before income taxes	(44)	424	357	744
Income tax provision (benefit):				
Current	38	9	134	39
Deferred	(49)	146	5	234
Total income tax provision (benefit)	(11)	155	139	273
Net income (loss)	$ (33)	$ 269	$ 218	$ 471
Earnings (loss) per share:				
Basic	$ (0.24)	$ 2.00	$ 1.62	$ 3.52
Diluted	$ (0.24)	$ 1.99	$ 1.61	$ 3.49
Weighted-average number of shares outstanding for basic earnings (loss) per share	135	134	134	134
Weighted-average number of shares outstanding for diluted earnings (loss) per share	135	135	135	135

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income (loss)	$ (33)	$ 269	$ 218	$ 471
Other comprehensive income (loss):				
Unrealized gain (loss) on investments, net of tax	—	(2)	2	2
Other comprehensive income (loss), net of tax	—	(2)	2	2
Comprehensive income (loss)	$ (33)	$ 267	$ 220	$ 473

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)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash flows from operating activities:		
Net income	$218	$471
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	702	528
Deferred tax provision	5	234
Stock-based compensation	27	20
Commodity derivative income	(61)	(249)
Cash receipts on derivative settlements, net	123	156
Other non-cash charges	11	2
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(43)	34
Increase in inventories	(21)	(24)
Increase in other current assets	(21)	(17)
(Increase) decrease in other assets	7	(6)
Increase (decrease) in accounts payable and accrued liabilities	(116)	24
Increase (decrease) in advances from joint owners	(19)	5
Decrease in other liabilities	(8)	(5)
Net cash provided by operating activities	804	1,173
Cash flows from investing activities:		
Additions to oil and gas properties	(1,279)	(1,723)
Acquisitions of oil and gas properties	(9)	(299)
Proceeds from sales of oil and gas properties	382	202
Additions to furniture, fixtures and equipment	(15)	(23)
Redemptions of investments	—	1
Net cash used in investing activities	(921)	(1,842)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	2,347	3,148
Repayments of borrowings under credit arrangements	(2,288)	(3,217)
Proceeds from issuance of senior notes	1,000	750
Debt issue costs	(10)	(16)
Repayment of senior subordinated notes	(875)	—
Proceeds from issuances of common stock	1	12
Purchases of treasury stock, net	(9)	(16)
Net cash provided by financing activities	166	661
Increase (decrease) in cash and cash equivalents	49	(8)
Cash and cash equivalents, beginning of period	76	39
Cash and cash equivalents, end of period	$125	$31

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
Issuances of common stock	0.1	—			1			1
Stock-based compensation					36			36
Treasury stock, net			0.4	11	(20)			(9)
Net income						218		218
Other comprehensive income, net of tax							2	2
Balance, September 30, 2012	136.5	$ 1	(1.3)	$ (39)	$ 1,512	$ 2,702	$ (8)	$ 4,168

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 natural 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 and $0.3 million for the three-month periods ended September 30, 2012 and 2011, respectively, and approximately $2 million and $1 million for the nine-month periods ended September 30, 2012 and 2011, respectively.

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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 740,000 barrels and 239,000 barrels of crude oil valued at cost of $49 million and $19 million at September 30, 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 $29 million and $30 million of internal costs during the three-month periods ended September 30, 2012 and 2011, respectively, and $87 million and $81 million during the nine-month periods ended September 30, 2012 and 2011, respectively. Interest expense related to unproved properties is capitalized into oil and gas properties.

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

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

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

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

- related income tax effects.

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

The risk that we will be required to writedown the carrying value of our 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 September 30, 2012, the ceiling value of our reserves was calculated based upon the unweighted-average first-day-of-the-month commodity prices for the prior 12 months of $2.83 per MMBtu for natural gas and $95.05 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 September 30, 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 transfer of the ARO to purchasers of our divested properties.

In general, the amount of an ARO and the costs capitalized will equal the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the 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.

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The change in our ARO for the nine months ended September 30, 2012 is set forth below (in millions):

Balance at January 1, 2012	$	145
Accretion expense		8
Additions		8
Revisions		12
Settlements		(24)
Balance at September 30, 2012		149
Less: Current portion of ARO at September 30, 2012		(6)
Total long-term ARO at September 30, 2012	$	143

Income Taxes

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

Derivative Financial Instruments

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions, except per share data)			
Income (numerator):				
Net income (loss) — basic and diluted	$ (33)	$ 269	$ 218	$ 471
Weighted-average shares (denominator):				
Weighted-average shares — basic	135	134	134	134
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period(1)(2)	—	1	1	1
Weighted-average shares — diluted	135	135	135	135

Earnings (loss) per share:				
Basic	$ (0.24)	$ 2.00	$ 1.62	$ 3.52
Diluted	$ (0.24)	$ 1.99	$ 1.61	$ 3.49

(1) The effect of stock options and unvested restricted stock and restricted stock units outstanding has not been included in the calculation of shares outstanding for diluted EPS for the three months ended September 30, 2012 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 0.6 million shares for the three months ended September 30, 2012.

(2) The calculation of shares outstanding for diluted EPS for the nine months ended September 30, 2012 excludes the effect of 3 million unvested restricted stock or restricted stock units and stock options, and the calculation of shares outstanding for diluted EPS for the three and nine months ended September 30, 2011 excludes the effect of 1 million unvested restricted stock or restricted stock units and stock options because including the effect would be anti-dilutive.

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3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	September 30, 2012	December 31, 2011
	(In millions)	
Oil and gas properties:		
Subject to amortization	$13,456	$12,423
Not subject to amortization	2,009	1,965
Gross oil and gas properties	15,465	14,388
Accumulated depreciation, depletion and amortization	(7,131)	(6,436)
Net oil and gas properties	8,334	7,952
Other property and equipment	152	138
Accumulated depreciation and amortization	(80)	(70)
Net other property and equipment	72	68
Total property and equipment, net	$8,406	$8,020

The following is a summary of our oil and gas properties not subject to amortization as of September 30, 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, the entire evaluation will take significantly longer than four years. At September 30, 2012, approximately 77% 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	$105	$296	$299	$411	$1,111
Exploration costs	390	44	22	34	490
Development costs	48	62	25	36	171
Fee mineral interests	—	—	—	23	23
Capitalized interest	53	78	55	28	214
Total oil and gas properties not subject to amortization	$596	$480	$401	$532	$2,009

Non-Strategic Asset Sales

During the nine months ended September 30, 2012 and the year ended December 31, 2011, we received payment for sales of non-strategic assets of approximately $382 million and $406 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. On October 5, 2012, we closed the sale of our remaining Gulf of Mexico assets. See Note 14, “Subsequent Events.”

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 income 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 while we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor 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 September 30, 2012, we had outstanding contracts with respect to our future production that were not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu							
			Collars						Estimated Fair Value
		Swaps	Additional Put		Floors		Ceilings		
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Asset (Liability) (In millions)
October 2012 – December 2012									
Price swap contracts	11,340	$3.19	¾	¾	¾	¾	¾	¾	$ 1
Price swap contracts	(A)	2.72	¾	¾	¾	¾	¾	¾	(9)
3-Way collar contracts	15,070	—	$3.50-$4.50	$4.19	$5.00-$6.00	$5.51	$5.20-$7.55	$6.41	19
January 2013 – December 2013									
Price swap contracts	54,750	4.08	¾	¾	¾	¾	¾	¾	13
Price swap contracts	(A)	3.45	¾	¾	¾	¾	¾	¾	(15)
3-Way collar contracts	39,530	—	3.50-4.50	4.04	5.00-6.00	5.44	6.00-7.55	6.48	42
January 2014 – December 2014									
Price swap contracts	54,750	3.85	¾	¾	¾	¾	¾	¾	(17)
Collar contracts	14,600	¾	¾	¾	3.75	3.75	4.54-4.57	4.55	(1)

$ 33

(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 October 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 $4.04 and $4.85 per MMBtu for the fourth quarter of 2012 and the full-year 2013, respectively, as long as natural gas spot prices for the respective time periods settle 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

Period and Type of Contract	Volume in MBbls	NYMEX Contract Price Per Bbl: Additional Put Range	Additional Put Weighted Average	Collars: Floors Range	Floors Weighted Average	Ceilings Range	Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
October 2012 – December 2012								
3-Way collar contracts	3,220	$55.00-$90.00	$66.86	$75.00-$100.00	$82.96	$91.90-$137.80	$108.30	$ 1
January 2013 – December 2013								
3-Way collar contracts	12,115	80.00	80.00	95.00	95.00	106.50-130.40	118.05	30
January 2014 – December 2014								
3-Way collar contracts	5,110	80.00	80.00	95.00	95.00	117.50-120.75	119.16	14
								$ 45

Basis Contracts

At September 30, 2012, we had natural gas basis contracts that were 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
	Volume in	Weighted-	Volume in	Weighted-	Fair Value

	MMMbtus	Average Differential	MMMbtus	Average Differential	Asset (Liability) (In millions)
October 2012 – December 2012	1,230	$ (0.91)	4,600	$ (0.55)	$ (3)

Additional Disclosures about Derivative Instruments and Hedging Activities

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

Type of Contract	Balance Sheet Location	September 30, 2012	December 31, 2011
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Derivative assets – current	$ 65	$ 133
Oil contracts	Derivative assets – current	24	1
Basis contracts	Derivative assets – current	(1)	(5)
Natural gas contracts	Derivative assets – noncurrent	1	61
Oil contracts	Derivative assets – noncurrent	21	—
Natural gas contracts	Derivative liabilities – current	(17)	—
Oil contracts	Derivative liabilities – current	—	(45)
Basis contracts	Derivative liabilities – current	(2)	(5)
Natural gas contracts	Derivative liabilities – noncurrent	(16)	—
Oil contracts	Derivative liabilities – noncurrent	—	(3)
Total		$ 75	$ 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 September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
		(In millions)			
Derivatives not designated as hedging instruments:					
Realized gain on natural gas contracts	Commodity derivative income (expense)	$ 37	$ 68	$ 135	$ 198
Realized gain (loss) on oil contracts	Commodity derivative income (expense)	3	(5)	(4)	(37)
Realized loss on basis contracts	Commodity derivative income (expense)	(3)	(2)	(8)	(5)
Total realized gain		37	61	123	156
Unrealized gain (loss) on natural gas contracts	Commodity derivative income (expense)	(79)	5	(162)	(68)
Unrealized gain (loss) on oil contracts	Commodity derivative income (expense)	(59)	197	92	162
Unrealized gain (loss) on basis contracts	Commodity derivative income (expense)	3	(1)	8	(1)
Total unrealized gain (loss)		(135)	201	(62)	93
Total		$ (98)	$ 262	$ 61	$ 249

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 September 30, 2012, six of our 14 counterparties accounted for approximately 85% of our estimated future hedged production with no single counterparty accounting for more than 25% of that 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:

	September 30, 2012	December 31, 2011
	(In millions)	

Revenue	$298	$301
Joint interest	124	96
Other	6	11
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$427	$407

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

6. Accrued Liabilities:

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

	September 30, 2012	December 31, 2011
	(In millions)	
Revenue payable	$86	$94
Accrued capital costs	332	231
Accrued lease operating expenses	84	86
Employee incentive expense	46	61
Accrued interest on debt	46	52
Taxes payable	116	122
Other	37	41
Total accrued liabilities	$747	$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, and other financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques for derivative instruments, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

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

Fair Value of Investments and Derivative Instruments

The following table summarizes the valuation of our 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 contracts	—	66	(10)	56
Oil and gas derivative option contracts	—	—	81	81
Total	$ 10	$ 66	$ 103	$ 179
As of September 30, 2012:				
Money market fund investments	$ 13	$ —	$ —	$ 13
Investments available-for-sale:				
Equity securities	12	—	—	12
Auction rate securities	—	—	34	34
Oil and gas derivative swap contracts	—	(27)	(3)	(30)
Oil and gas derivative option contracts	—	—	105	105
Total	$ 25	$ (27)	$ 136	$ 134

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 September 30, 2012, we held $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.

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

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

	Investments	Derivatives	Total
		(In millions)	
Balance at January 1, 2011	$30	$48	$78
Total realized or unrealized gains (losses):			
Included in earnings	—	163	163
Included in other comprehensive income	3	—	3
Purchases, issuances and settlements:			
Settlements	(1)	(42)	(43)
Transfers in and out of Level 3	—	—	—
Balance at September 30, 2011	$32	$169	$201
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at September 30, 2011	$—	$150	$150
Balance at January 1, 2012	$32	$71	$103
Total realized or unrealized gains (losses):			
Included in earnings	—	100	100
Included in other comprehensive income	2	—	2
Purchases, issuances and settlements:			
Settlements	—	(69)	(69)
Transfers in and out of Level 3	—	—	—
Balance at September 30, 2012	$34	$102	$136
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at September 30, 2012	$—	$67	$67

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)	Quantitative Information about Level 3 Fair Value Measurements Valuation Technique	Unobservable Input	Range
Basis contracts	$ (3)	Discounted cash flow	NYMEX Natural gas price forward curve	$ 2.93 - $ 3.62
			Physical pricing point forward curves	$ 2.72 - $ 3.50
			Credit risk	0.02 % - 0.08 %
Oil 3-way collar contracts	$ 45	Option model	NYMEX Oil price forward curve	$ 90.77 - $ 94.12
			Oil price volatility curves	22.32 % - 39.69 %
			Credit risk	0.01 % - 4.00 %
Natural gas collars and 3-way collar contracts	$ 60	Option model	NYMEX Natural gas price forward curve	$ 2.93 - $ 4.44
			Natural gas price volatility curves	23.12 % - 44.24 %
			Credit risk	0.01 % - 4.08 %

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:

	September 30, 2012	December 31, 2011
	(In millions)	
5¾% Senior Notes due 2022	$840	$808
5 % Senior Notes due 2024	1,117	—
6 % Senior Subordinated Notes due 2014	—	329
6 % Senior Subordinated Notes due 2016	—	568
7 % Senior Subordinated Notes due 2018	635	635
6 % Senior Subordinated Notes due 2020	770	745

Amounts outstanding under our credit arrangements at September 30, 2012 and December 31, 2011 are stated at cost, which approximates fair value. Please see Note 8, “Debt.”

8. Debt:

Debt consisted of the following at:

	September 30, 2012	December 31, 2011
	(In millions)	
Senior unsecured debt:		
Revolving credit facility LIBOR based loans	$145	$85
Money market lines of credit(1)	—	1
Total credit arrangements	145	86
5¾% Senior Notes due 2022	750	750
5 % Senior Notes due 2024	1,000	—
Total senior unsecured debt	1,895	836
6 % Senior Subordinated Notes due 2014	—	325
6 % Senior Subordinated Notes due 2016	—	550
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	695	695
Total long-term debt	$3,190	$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.

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 September 30, 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 September 30, 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 September 30, 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 September 30, 2012). We incurred aggregate commitment fees under our current credit facility of approximately $0.9 million and $2.5 million for the three and nine months ended September 30, 2012, respectively, which are recorded in “Interest expense” on our consolidated statement of net income. For the three and nine months ended September 30, 2011, we incurred commitment fees under our current and previous credit facility of approximately $0.3 million and $1.2 million, respectively.

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 September 30, 2012, we were in compliance with all of our debt covenants.

As of September 30, 2012, we had $15 million of undrawn letters of credit outstanding under our credit facility. Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at September 30, 2012). Additionally, as of September 30, 2012, we had $5 million of other undrawn letters of credit outstanding.

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

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.

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

Senior and Senior Subordinated Notes

In September 2011, we issued $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.

In April 2012, we redeemed our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest, which included the payment of an early redemption premium of $4 million. This premium was recorded under the caption "Other income (expenses) – Other" on our consolidated statement of net income. The repayment of the outstanding principal balance of $325 million was funded through the use of our revolving credit facility. In addition, unamortized offering costs of approximately $0.6 million were written off.

In June 2012, we issued $1 billion of 5 % Senior Notes due 2024 and received proceeds of $990 million (net of offering costs of approximately $10 million). These notes were issued at par to yield 5 %. We used a portion of the net proceeds to repay borrowings outstanding under our credit facility and money market lines of credit, as well as in July 2012, redeem our $550 million aggregate principal amount of 6 % Senior Subordinated Notes due 2016. In connection with the redemption, we paid a premium of $14 million. The premium was recorded under the caption "Other income (expenses) – Other" on our consolidated statement of income. In addition, unamortized offering costs of approximately $2 million were written off in July 2012 as a result of the repayment.

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Amount computed using the statutory rate	$(15)	$148	$125	$260
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect	(1)	4	3	9
Net effect of different tax rates in non-U.S. jurisdictions	5	—	11	1
Other	—	3	—	3
Total provision (benefit) for income taxes	$(11)	$155	$139	$273

As of September 30, 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 2009-2011 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:

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Total stock-based compensation	$13	$9	$37	$28
Capitalized in oil and gas properties	(3)	(3)	(10)	(8)
Net stock-based compensation expense	$10	$6	$27	$20

As of September 30, 2012, we had approximately $94 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.

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Stock Options. The following table provides information about stock option activity for the nine months ended September 30, 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	(0.1)	20.30			1
Outstanding at September 30, 2012	1.0	$37.52		3.5	$2
Exercisable at September 30, 2012	0.9	$36.61		3.3	$2

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

On September 30, 2012, the last reported sales price of our common stock on the New York Stock Exchange was $31.32 per share.

Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity for the nine months ended September 30, 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	1.4	0.2	1.6	36.12
Forfeited	(0.2)	—	(0.2)	47.73
Vested	(0.9)	(0.1)	(1.0)	41.80
Non-vested shares outstanding at September 30, 2012	2.5	0.4	2.9	$ 44.37

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

September 30, 2012, approximately 77,000 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 six months of 2012, options to purchase approximately 87,000 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%.

On July 1, 2012, options to purchase approximately 83,000 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $7.93 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 0.15%, an expected life of six months and weighted-average volatility of 44%.

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

12. 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.”

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The following tables provide the geographic operating segment information for the three and nine months ended September 30, 2012 and 2011. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

Three Months Ended
September 30, 2012:

	Domestic	Malaysia	China	Total
		(In millions)		
Oil and gas revenues	$ 371	$ 228	$ 16	$ 615
Operating expenses:				
Lease operating	99	27	2	128
Production and other taxes	17	59	3	79
Depreciation, depletion and amortization	172	61	4	237
General and administrative	57	2	—	59
Other	6	—	—	6
Allocated income tax	7	30	2	
Net income from oil and gas properties	$ 13	$ 49	$ 5	
Total operating expenses				509
Income from operations				106
Interest expense, net of interest income, capitalized interest and other				(52)
Commodity derivative expense				(98)
Loss before income taxes				$ (44)
Total assets	$ 8,235	$ 878	$ 318	$ 9,431
Additions to long-lived assets	$ 362	$ 61	$ 30	$ 453

Three Months Ended
September 30, 2011:

	Domestic	Malaysia	China	Total
		(In millions)		
Oil and gas revenues	$ 444	$ 159	$ 25	$ 628
Operating expenses:				
Lease operating	93	21	1	115
Production and other taxes	19	71	5	95
Depreciation, depletion and amortization	154	29	6	189
General and administrative	49	1	1	51
Allocated income tax	48	14	3	
Net income from oil and gas properties	$ 81	$ 23	$ 9	

Total operating expenses				450
Income from operations				178
Interest expense, net of interest income, capitalized interest and other				(16)
Commodity derivative income				262
Income before income taxes				$ 424
Total assets	$ 7,879	$ 789	$ 235	$ 8,903
Additions to long-lived assets	$ 597	$ 81	$ 13	$ 691

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Nine Months Ended September 30, 2012:

	Domestic	Malaysia	China	Total
		(In millions)		
Oil and gas revenues	$1,124	$724	$73	$1,921
Operating expenses:				
Lease operating	305	73	6	384
Production and other taxes	53	182	15	250
Depreciation, depletion and amortization	510	175	17	702
General and administrative	161	4	—	165
Other	6	—	—	6
Allocated income tax	33	110	9	
Net income from oil and gas properties	$56	$180	$26	
Total operating expenses				1,507
Income from operations				414
Interest expense, net of interest income, capitalized interest and other				(118)
Commodity derivative income				61
Income before income taxes				$357
Total assets	$8,235	$878	$318	$9,431
Additions to long-lived assets	$1,246	$130	$50	$1,426

Nine Months Ended September 30, 2011:

	Domestic	Malaysia	China	Total
		(In millions)		
Oil and gas revenues	$1,313	$416	$65	$1,794
Operating expenses:				
Lease operating	260	69	4	333
Production and other taxes	56	173	16	245
Depreciation, depletion and amortization	440	73	15	528
General and administrative	128	3	1	132
Allocated income tax	159	37	7	
Net income from oil and gas properties	$270	$61	$22	
Total operating expenses				1,238
Income from operations				556
Interest expense, net of interest income, capitalized interest and other				(61)

Commodity derivative income				249
Income before income taxes				$744
Total assets	$7,879	$789	$235	$8,903
Additions to long-lived assets	$1,858	$208	$48	$2,114

13. Supplemental Cash Flows Information:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Non-cash items excluded from the statement of cash flows:				
Increase in accrued capital expenditures	$(35)	$(38)	$(101)	$(48)
Increase in asset retirement costs	(9)	(2)	(14)	(10)

14. Subsequent Events:

On October 5, 2012, we closed on the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for $208 million, subject to post-closing adjustments. The sale of our remaining assets in the Gulf of Mexico does not significantly alter the relationship between capitalized costs and proved reserves and as such, all proceeds will be recorded as adjustments to our domestic full cost pool with no gain or loss recognized. We received $23 million of the purchase price during the third quarter of 2012, which is included as proceeds from sales of oil and gas properties in the statement of cash flows. These consolidated financial statements include the results of our Gulf of Mexico operations, consistent with prior periods. Production associated with our Gulf of Mexico operations, excluding natural gas produced and consumed in our operations, was 4 Bcfe for the three months ended September 30, 2012.

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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.

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

We prepare our financial statements in conformity with generally accepted accounting principles, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and natural gas reserves. In addition, we use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these assets, are capitalized. The net capitalized costs for our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves. If these costs exceed the limit, we are required to charge the excess to earnings, also referred to as a “ceiling test writedown”. The risk of incurring a ceiling test writedown increases when commodity prices are low for a sustained period of time. If we assume the unweighted-average first-day-of-the-month commodity prices for the remainder of 2012 were the same as October 2012 commodity prices of $3.09 per MMBtu for natural gas and $92.45 per barrel of oil, adjusted for market differentials, which were approximately 9% higher for natural gas and 3% lower for oil than the unweighted-average first-day-of-the-month commodity prices for the prior 12 months, we would not anticipate a ceiling test writedown during 2012. However, if there are further declines in the 12-month unweighted-average commodity prices, we may be required to record a ceiling test writedown in future periods.

Quarter Highlights. A few significant highlights for the third quarter of 2012 include the following:

- Consistent with our focus on oil, our oil and liquids sales and liftings for the third quarter of 2012 were over 20% higher than the third quarter of 2011, resulting in approximately 49% of our total production during the third quarter 2012 coming from oil and liquids, as compared to approximately 40% for the third quarter 2011.
- Our assessment program on approximately 142,000 net acres in the Cana Woodford continued and delivered an additional four successful appraisal wells, for a year-to-date total of 10 successful appraisal wells.
- Our offshore production in Malaysia averaged over 28,000 BOPD (net) during the third quarter of 2012, an increase of 69% over the same period in 2011.
- We completed the tender offer and redemption of our $550 million 6 % Senior Subordinated Notes due 2016.

Current Outlook. We currently expect 2012 total production to be approximately 298 Bcfe, of which approximately 49% is expected to be oil and natural gas liquids. On a consolidated basis, we expect our 2012 oil and liquids production to grow by more than 20% over 2011. During 2012, we accelerated our Malaysian production by drilling additional development wells and benefitted from increased pipeline capacity. Our international oil production exceeded our beginning of year expectations and grew by approximately 50% over 2011 levels. Our net production in Malaysia is dictated by the terms of various production sharing contracts ("PSCs"). These contracts provide for a change in our net revenue interest when certain milestones are reached. As a result of (i) the additional volumes produced, which benefitted from higher Brent oil prices, (ii) our expectations for natural field decline, (iii) our expectations for oil prices to be received in 2013 and (iv) our levels of capital expenditures in various fields under different PSCs, we expect our average net revenue interest to be at a level such that our 2013 international oil volumes will decline about 25% from 2012 levels.

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 derivative positions. Please see Note 4, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from period-to-period as a result of changes in commodity prices or volumes of production sold. In addition, substantially all of the crude oil from our 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.

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Revenues of $615 million for the third quarter of 2012 were slightly lower than the comparable period of 2011. Revenues of $1.9 billion for the first nine months of 2012 were 7% higher than the comparable period of 2011. The 21% increase in oil, condensate and NGLs production during the third quarter of 2012 was offset by a slight decrease in average realized prices for all products and a 16% decrease in natural gas production as compared to the comparable period of 2011. The 31% increase in oil, condensate and NGLs production and slight increase in average realized prices for these products for the nine-month period ended September 30, 2012 was partially offset by the 15% decrease in natural gas production and a 40% decrease in average realized natural gas prices for the comparable period of 2011.

The following table summarizes production and average realized prices by product and by geographic area for the three- and nine-month periods ended September 30, 2012 and 2011.

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Percentage Increase (Decrease)	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Percentage Increase (Decrease)
Production:(1)						
Domestic:						
Natural gas (Bcf)	36.7	43.8	(16)%	112.8	132.8	(15)%
Oil, condensate and NGLs (MBbls)	3,818	3,392	13 %	10,958	9,407	16 %
Total (Bcfe)	59.6	64.2	(7)%	178.5	189.3	(6)%
International:						
Natural gas (Bcf)	0.3	—	100 %	0.7	—	100 %
Oil, condensate and NGLs (MBbls)	2,319	1,678	38 %	7,179	4,397	63 %
Total (Bcfe)	14.2	10.1	41 %	43.8	26.4	66 %
Total:						
Natural gas (Bcf)	37.0	43.8	(16)%	113.5	132.8	(15)%
Oil, condensate and NGLs (MBbls)	6,137	5,070	21 %	18,137	13,804	31 %
Total (Bcfe)	73.8	74.3	(1)%	222.3	215.7	3 %
Average Realized Prices:(2)						
Domestic:						
Natural gas (per Mcf)	$2.64	$4.22	(37)%	$2.51	$4.21	(40)%
Oil, condensate and NGLs (per Bbl)	71.45	75.99	(6)%	76.29	79.63	(4)%
Natural gas equivalent (per Mcfe)	6.23	6.92	(10)%	6.30	6.94	(9)%
International:						
Natural gas (per Mcf)	$3.88	$—	100 %	$4.04	$—	100 %
Oil, condensate and NGLs (per Bbl)	104.67	109.62	(5)%	110.54	109.31	1 %
Natural gas equivalent (per Mcfe)	17.17	18.27	(6)%	18.19	18.22	— %
Total:						
Natural gas (per Mcf)	$2.65	$4.22	(37)%	$2.52	$4.21	(40)%
	84.01	87.12	(4)%	89.85	89.09	1 %

Oil, condensate and NGLs (per Bbl)						
Natural gas equivalent (per Mcfe)	8.34	8.46	(1) %	8.64	8.32	4 %

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(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in our operations of 1.7 Bcfe and 1.6 Bcfe during the three months ended September 30, 2012 and 2011, respectively, and 5.7 Bcfe and 4.9 Bcfe during the nine months ended September 30, 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 $3.57 and $5.72 per Mcf for the three months ended September 30, 2012 and 2011, respectively, and $3.64 and $5.67 per Mcf for the nine months ended September 30, 2012 and 2011, respectively. Our total oil, condensate and NGLs average realized price would have been $84.50 and $86.16 per Bbl for the three months ended September 30, 2012 and 2011, respectively, and $89.62 and $86.38 per Bbl for the nine months ended September 30, 2012 and 2011, respectively.

Domestic Production. Consistent with our expectations, we continued to experience declining natural gas production for the three-month period ended September 30, 2012 as compared to the same period of 2011 due to natural field declines, maintenance- and hurricane-related shut-ins and the sale of non-strategic assets. Decreases in natural gas production in our Onshore Gulf Coast and Mid-Continent divisions and Gulf of Mexico operations were partially offset by increases in oil and liquids production across each of our domestic divisions.

The 10.8 Bcfe decrease in domestic production for the nine-month period ended September 30, 2012 as compared to the same period of 2011 was primarily related to decreased natural gas production in our Gulf of Mexico operations and Onshore Gulf Coast division primarily due to natural field declines, maintenance- and hurricane-related shut-ins and the sale of non-strategic assets. Consistent with our shift to liquids, our continued successful assessment and development drilling efforts for oil and liquids across each of our domestic divisions partially offset the decline in natural gas production.

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International Production. Our international oil production for the three- and nine-month periods ended September 30, 2012 increased over the comparable periods of 2011 primarily due to production from our East Piatu and Puteri fields, brought online during the fourth quarter of 2011.

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 September 30, 2012 and 2011.

	Unit-of-Production Three Months Ended September 30, 2012 (Per Mcfe)	Unit-of-Production Three Months Ended September 30, 2011 (Per Mcfe)	Percentage Increase (Decrease)	Total Amount Three Months Ended September 30, 2012 (In millions)	Total Amount Three Months Ended September 30, 2011 (In millions)	Percentage Increase (Decrease)
Domestic:						
Lease operating	$ 1.67	$ 1.45	15 %	$ 99	$ 93	7 %
Production and other taxes	0.28	0.29	(3) %	17	19	(9) %
Depreciation, depletion and amortization	2.89	2.40	20 %	172	154	12 %
General and administrative	0.96	0.76	26 %	57	49	17 %
Other	0.10	—	100 %	6	—	100 %
Total operating expenses	5.90	4.91	20 %	351	315	12 %
International:						
Lease operating	$ 2.07	$ 2.18	(5) %	$ 29	$ 22	34 %
Production and other taxes	4.37	7.63	(43) %	62	76	(19) %
Depreciation, depletion and amortization	4.53	3.49	30 %	65	35	83 %
General and administrative	0.11	0.14	(21) %	2	2	13 %
Total operating expenses	11.08	13.44	(18) %	158	135	16 %
Total:						
Lease operating	$ 1.74	$ 1.55	12 %	$ 128	$ 115	12 %
Production and other taxes	1.07	1.28	(16) %	79	95	(17) %
Depreciation, depletion and amortization	3.21	2.55	26 %	237	189	25 %
General and administrative	0.80	0.68	18 %	59	51	17 %
Other	0.08	—	100 %	6	—	100 %
Total operating expenses	6.90	6.06	14 %	509	450	13 %

Domestic Operations. Our domestic operating expenses for the three months ended September 30, 2012, stated on a per Mcfe basis, increased 20% over the same period of 2011. The components of the period-to-period change are as follows:

- Lease operating expenses (LOE) include normally recurring expenses to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. The increase in total domestic LOE per Mcfe primarily resulted from a $0.11 per Mcfe increase in non-recurring costs related to well workovers and repairs, primarily in our Gulf of Mexico operations and Mid-Continent division and a $0.09 per Mcfe increase due to additional transportation costs related to firm transportation agreements in our Mid-Continent division.

•Since late 2009, the continued 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 $23 million ($0.39 per Mcfe) and $21 million ($0.33 per Mcfe) of direct internal costs during the third quarters of 2012 and 2011, respectively.

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International Operations. Our international operating expenses for the three months ended September 30, 2012, stated on a per Mcfe basis, decreased 18% 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 during the third quarter of 2012 resulting from production from our East Piatu and Puteri fields, brought online during the fourth quarter of 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 as stated above and due to lower average realized oil prices during the third quarter of 2012. In addition, the tax rates per barrel of oil lifted and sold from these developments are lower, per the terms of our PSCs, while we recover our costs associated with these developments.

•Our DD&A rate increased 30% primarily due to the recognition of future development costs in the fourth quarter of 2011 associated with our offshore developments in Malaysia, which increased our 2012 DD&A rate but not the rate for the comparable period of 2011.

The following table presents information about our operating expenses for the nine months ended September 30, 2012 and 2011.

	Unit-of-Production			Total Amount		
	Nine Months Ended September 30,		Percentage Increase (Decrease)	Nine Months Ended September 30,		Percentage Increase (Decrease)
	2012	2011		2012	2011	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 1.71	$ 1.38	24 %	$ 305	$ 260	17 %
Production and other taxes	0.30	0.30	—	53	56	(6) %
Depreciation, depletion and amortization	2.86	2.33	23 %	510	440	16 %
General and administrative	0.90	0.68	32 %	161	128	26 %
Other	0.03	—	100 %	6	—	100 %
Total operating expenses	5.80	4.67	24 %	1,035	884	17 %
International:						
Lease operating	$ 1.80	$ 2.75	(35) %	$ 79	$ 73	9 %
Production and other taxes	4.50	7.17	(37) %	197	189	4 %
Depreciation, depletion and amortization	4.39	3.35	31 %	192	88	118 %
General and administrative	0.09	0.15	(40) %	4	4	5 %
Total operating expenses	10.77	13.41	(20) %	472	354	33 %
Total:						
Lease operating	$ 1.73	$ 1.54	12 %	$ 384	$ 333	15 %
Production and other taxes	1.12	1.14	(2) %	250	245	2 %

Depreciation, depletion and amortization	3.16	2.45	29	%	702	528	33	%
General and administrative	0.74	0.61	21	%	165	132	25	%
Other	0.03	—	100	%	6	—	100	%
Total operating expenses	6.78	5.74	18	%	1,507	1,238	22	%

Domestic Operations. Our domestic operating expenses for the nine months ended September 30, 2012, stated on a per Mcfe basis, increased 24% over the same period of 2011. The components of the period-to-period change are as follows:

•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. Non-recurring costs in our Gulf of Mexico deepwater operations and Rocky Mountain division accounted for approximately 36% ($0.12 per Mcfe) of the overall increase primarily due to well workovers and repairs. Transportation costs in our Mid-Continent and Onshore Gulf Coast divisions related to firm transportation agreements accounted for 27% ($0.09 per Mcfe) of the total increase in domestic LOE. Recurring LOE accounted for approximately 27% ($0.09 per Mcfe) of the overall increase primarily due to increased operating and service-related costs in our Rocky Mountain division ($0.12 per Mcfe), partially offset by reduced operating and service-related costs and reduced production from non-strategic asset sales in our Onshore Gulf Coast division and lower production in our Gulf of Mexico operations ($0.05 per Mcfe) as a result of non-strategic asset sales.

•Since late 2009, the continued shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our DD&A rate, resulting in the increase in DD&A expense.

•G&A expense per Mcfe increased primarily due to employee-related expenses associated with our growing domestic work force. During the nine months ended September 30, 2012, we capitalized $70 million ($0.39 per Mcfe), as compared to $59 million ($0.31 per Mcfe) during the same period of 2011.

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International Operations. Our international operating expenses for the nine months ended September 30, 2012, stated on a per Mcfe basis, decreased 20% 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 nine months of 2012, resulting from production from our East Piatu and Puteri fields, brought online during the fourth quarter of 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 as stated above during the first nine months of 2012. In addition, the tax rates per barrel of oil lifted and sold from the new developments are lower, per the terms of our PSCs, while we recover our costs associated with these developments.

- Our DD&A rate increased 31% primarily due to the recognition of future development costs in the fourth quarter of 2011 associated with our offshore developments in Malaysia, which increased our 2012 DD&A rate but not the rate for the comparable period of 2011.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Gross interest expense:				
Credit arrangements	$2	$5	$7	$9
Senior notes	25	—	48	—
Senior subordinated notes	26	38	98	114
Other	—	—	—	1
Total gross interest expense	53	43	153	124
Capitalized interest	(17)	(24)	(53)	(61)
Net interest expense	$36	$19	$100	$63

The increase in gross interest expense for the three and nine months ended September 30, 2012 as compared to the same periods of 2011 primarily resulted from the September 2011 issuance of $750 million aggregate principal amount of 5¾% Senior Notes due 2022, as well as the June 2012 issuance of $1 billion aggregate principal amount of 5 % Senior Notes due 2024, partially offset by the redemption in April 2012 of our $325 million 6 % Senior Subordinated Notes due 2014 and our July 2012 $550 million 6 % Senior Subordinated Notes due 2016. 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 rate was 26% for the third quarter of 2012 and 39% for the first nine months of 2012 compared to 37% for the same time periods in 2011. Our effective tax rate generally approximates 37%. The primary variance from these effective rates in 2012 is due to differing tax rates for permanent book-tax differences in our international business units combined with the income tax benefit received from our net loss for the three months ended September 30, 2012. 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; 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, which includes cash flows from operations and non-strategic asset sales. 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 $1.7 billion and focuses on projects with higher return on investment, 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. 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 nine months of 2012, we:

- received proceeds from the sale of non-strategic assets of $382 million;
- repurchased our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014;
- repurchased our $550 million aggregate principal of 6 % Senior Subordinated Notes due 2016; and
- issued $1 billion aggregate principal of 5 % Senior Notes due 2024.

We used a portion of the proceeds from the $1 billion Senior Notes offering combined with the proceeds from our non-strategic asset sale program to reduce borrowings outstanding under our credit arrangements, and as a result, at September 30, 2012, we had available borrowing capacity of $1.3 billion under our credit arrangements. We continue to market other non-strategic assets. On October 5, 2012, we announced the closing of the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for $208 million, subject to post-closing adjustments. We received $23 million of the purchase price during the third quarter of 2012. We expect to substantially fund our $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 and our ability to generate cash flows from our asset portfolio will be adequate to fund current and long-term 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 September 30, 2012, the largest individual commitment by any lender was 13% of total commitments.

In addition, subject to compliance with restrictive covenants in our credit facility, we also have a total of $195 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions. 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.

At October 22, 2012, we had oustanding borrowings of $100 million and $15 million of letters of credit under our credit facility and $11 million under our money market lines of credit. Our available borrowing capacity under our credit arrangements was approximately $1.3 billion, and we had $5 million of other undrawn letters of credit outstanding.

Senior and Senior Subordinated Notes. In April 2012, we redeemed our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest, which included the payment of an early redemption premium of $4 million. This premium was recorded under the caption "Other income (expenses) – Other" on our consolidated statement of net income. The repayment of the outstanding principal balance of $325 million was funded through the use of our revolving credit facility.

In June 2012, we issued $1 billion of 5 % Senior Notes due 2024 and received proceeds of $990 million (net of offering costs of approximately $10 million). These notes were issued at par to yield 5 %. We used a portion of the net proceeds to repay borrowings outstanding under our credit facility and money market lines of credit.

In July 2012, we redeemed our $550 million aggregate principal amount of 6 % Senior Subordinated Notes due 2016 and paid an early redemption premium of $14 million. We funded the redemption with a portion of the proceeds from our June 2012 Senior Notes issuance. The premium was recorded under the caption "Other income (expenses) – Other" on our consolidated statement of net income.

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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 September 30, 2012, we had negative working capital of $40 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.

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 36 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 $804 million for the nine months ended September 30, 2012, a decrease of $369 million compared to net cash flows from operations of $1.2 billion for the same period in 2011, primarily due to working capital changes. 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 nine months ended September 30, 2012 was $921 million compared to $1.8 billion for the same period in 2011.

During the nine months ended September 30, 2012, we:

- spent approximately $1.3 billion (including $9 million for acquisitions of oil and gas properties); and
- received proceeds of $382 million from sales of oil and gas properties.

During the nine months ended September 30, 2011, we:

- spent approximately $2.0 billion (including $299 million for acquisitions of oil and gas properties);
- received proceeds of $202 million from sales of oil and gas properties; and
- redeemed investments of $1 million.

Cash Flows from Financing Activities. Net cash provided by financing activities for the nine months ended September 30, 2012 were $166 million compared to $661 million for the same period in 2011.

During the nine months ended September 30, 2012, we:

- borrowed and repaid $2.3 billion under our credit arrangements;
- issued $1 billion aggregate principal amount of 5 % Senior Notes due 2024 at par and paid approximately $10 million in associated debt issue costs;
- repaid our $325 million aggregate principal amount of 6 % Senior Subordinated Notes due 2014;
- repaid our $550 million aggregate principal amount of 6 % Senior Subordinated Notes due 2016;
- received proceeds of $1 million from the issuance of shares of our common stock upon the exercise of stock options; and
- repurchased $10 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

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During the nine months ended September 30, 2011, we:

- borrowed $3.1 billion and repaid $3.2 billion under our credit arrangements;
- issued $750 million aggregate principal amount of our 5¾% Senior Notes due 2022 at 99.956% of par and paid approximately $8 million in associated debt issue costs;
- paid approximately $8 million in debt issue costs associated with our new revolving credit facility;
- received proceeds of $12 million from the issuance of shares of our common stock upon the exercise of stock options; and
- repurchased $18 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 $1.4 billion for the first nine months of 2012 decreased 22% from our capital investments of $1.8 billion during the same period of 2011. These amounts exclude acquisitions for the first nine months of 2012, which were immaterial, and $299 million during the same period of 2011 and recorded asset retirement obligations of $14 million and $9 million in the respective periods. Of the total $1.4 billion spent during the first nine months of 2012, we invested $991 million in domestic exploitation and development, $174 million in domestic exploration (exclusive of exploitation and leasehold activity), $59 million in leasing domestic proved and unproved property (leasehold) and $174 million outside the United States. Of the total $1.8 billion spent during the first nine months of 2011, we invested $1.2 billion in domestic exploitation and development, $182 million in domestic exploration (exclusive of exploitation and leasehold activity), $117 million in leasing domestic proved and unproved property (leasehold) and $249 million outside the United States.

We have budgeted approximately $1.7 billion for capital spending in 2012. The planned budget excludes capitalized interest and overhead of $210 million, as well as 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.

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. Significant changes in our contractual obligations during 2012 include the following:

- 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.
- In April 2012, we redeemed our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest. This terminates the related semi-annual interest payments of approximately $11 million that were scheduled through September 2014.
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In June 2012, we issued $1 billion of 5 % Senior Notes due 2024. These notes were issued at par to yield 5 %. The semi-annual interest payments of approximately $28 million associated with these notes are scheduled to commence in January 2013.

- In July 2012, we completed the tender and redemption of our $550 million aggregate principal of 6 % Senior Subordinated Notes due 2016. This terminates the related semi-annual interest payments of approximately $18 million that were scheduled through April 2016.

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 36 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.

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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 September 30, 2012, six of our 14 counterparties accounted for approximately 85% of our estimated future hedged production with no single counterparty accounting for more than 25% of that 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 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 94-98% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 1 Bcf of our natural gas production from October 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 4 Bcf of our anticipated natural gas production from the Stiles/Britt Ranch area for the period October 2012 through December 2012 at an average of \$0.55 per MMBtu less than the Henry Hub Index.

The price we receive for our Gulf Coast oil production, excluding NGLs, typically averages about 95-100% 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 September 30, 2012 and the estimated fair market value of those contracts as of that date.

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 non-cash volatility in our reported earnings during periods of commodity price volatility. As of September 30, 2012, we had net derivative assets of \$75 million, of which 35%, based on total hedged volumes, was measured based upon our valuation model (i.e. Black-Scholes) and, as such, is classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. As a result, the value of these contracts at their respective settlement dates could be significantly different than the fair value as of September 30, 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 for the year ended December 31, 2011 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.

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Other Factors. Please see “Risk Factors” in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2011 and Item 1A below 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 natural 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 public filings and press releases, including the factors dissussed in "Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates” included in our 2011 Annual Report on Form 10-K and the "Risk Factors" set forth below in Item 1A of this report.

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.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

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.

NGL. Natural gas liquid.

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

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 36 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 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 September 30, 2012, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility	$—	$145
5¾% Senior Notes due 2022	750	—
5 % Senior Notes due 2024	1,000	—
7 % Senior Subordinated Notes due 2018	600	—
6 % Senior Subordinated Notes due 2020	695	—
Total debt	$3,045	$145

We consider our interest rate exposure to be minimal because approximately 95% of our obligations were at fixed rates. Our variable rate debt is currently at an interest rate of 2%.

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 September 30, 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 September 30, 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 third 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 Environmental Protection Agency (EPA) alleging that we failed to provide adequate financial assurance for water injection wells falling under EPA jurisdiction that are located at our Monument Butte field in Duchesne County, Utah (Monument Butte). The injection wells are part of an enhanced oil recovery project designed to optimize production from Monument Butte. Regulations under the Safe Drinking Water Act, 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

The following risk factors update, and should be considered in addition to, the risk factors previously reported in our Annual Report on Form 10-K for the year ended December 31, 2011.

Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as Newfield, that participate in that market. The Dodd-Frank Reform Act is intended to reduce the risk of future financial crises and to make major changes to the U.S. financial regulatory system. While the Dodd-Frank Reform Act technically became effective on July 16, 2011, many provisions of the new law required the subsequent issuance of final rules by the Commodity Futures Trading Commission (CFTC) and SEC before those provisions become effective.

Of the final rules issued to date, some of the most significant rules implement new core principles for mandatory clearing and exchange trading requirements and institute a new customer margin segregation regime for cleared swaps. Moreover, on July 10, 2012, the CFTC and SEC adopted a final rule defining what constitutes a “swap” under the Dodd-Frank Reform Act and the other implemented final rules. The rulemaking also finalized the compliance dates for previously promulgated final rules (e.g. October 12, 2012), including the registration of swap dealers and major swap participants, required reporting of swap transactions to a swap data repository, and the implementation of aggregate position limits, which were contingent upon the adoption of the final “swap” definition.

The CFTC had previously issued a final rule in 2011 on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. However, a recent ruling by a federal district court vacated and remanded the regulations back to the CFTC for additional rulemaking action on the grounds that the CFTC did not comply with the Dodd-Frank Reform Act’s statutory instruction to demonstrate the necessity of position limits before imposing them.

There are substantial costs associated with the Dodd-Frank Reform Act that create disincentives for end-users like Newfield to reasonably hedge their commercial risk associated with anticipated production of oil and gas. As a result, the Dodd-Frank Reform Act, as implemented by final CFTC rule on July 10, 2012, contains an exception from the clearing requirement that is intended to be available to end-users at their election. The optional exception from the mandatory clearing and trading requirement is available to qualifying end-users under certain circumstances when the following conditions are satisfied: (i) end-user is not a financial entity; (ii) the swap is hedging or mitigating commercial risk; and (iii) the end-user satisfies certain notification and reporting obligations.

The CFTC end-user exception rule technically became effective on September 17, 2012. However, the CFTC noted that compliance will not be necessary or possible until swaps become subject to the clearing requirement. On July 24, 2012, the CFTC proposed the first set of swaps subject to mandatory clearing. Final rules determining which other swaps are subject to mandatory clearing and trading and final rules implementing swap execution facilities are expected by the end of 2012.

The Dodd-Frank Reform Act and any subsequent final rules and regulations promulgated by CFTC or SEC could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. If we reduce our use of derivatives or commodity prices decline as a result of the legislation and regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures, our results of operations, or our cash flows.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic-fracturing techniques on almost all of our U.S. onshore oil and natural gas properties, including our unconventional resource plays in the Woodford Shale of Oklahoma, the Granite Wash of Texas and Oklahoma, the Uinta Basin of Utah and the Eagle Ford and Pearsall shales of southwest Texas, which represented approximately 82% of our proved reserves and approximately 89% of our probable reserves at year-end 2011. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the Bureau of Land Management (BLM) and other federal regulatory agencies have taken steps to impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic fracturing process, and the RCT adopted rules regarding the same in December 2011. On September 11, 2012, the RCT approved new regulations relating to the commercial recycling of produced water and/or hydraulic fracturing flowback fluid.

In the past three years, news reports indicate that at least 23 states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Notwithstanding state regulatory requirements relating to hydraulic fracturing, there are steps by federal governmental agencies that are either underway or are being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and recently released draft permitting guidance for hydraulic fracturing activities using diesel. Further, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. In addition, on May 11, 2012, the BLM issued a proposed rule that that would require the public disclosure of chemicals used in hydraulic fracturing operations, set requirements for well-bore integrity and establish flowback water standards for all hydraulic fracturing operations on federal public lands and American Indian Tribal lands. The proposed rule also requires that an operator certify, in writing, that (a) the stimulation design complies with all federal, state, tribal and local regulations; (b) the stimulation was completed in accordance with the design approved by BLM and all applicable regulations; and (c) the well-bore integrity was maintained during the fracturing process and flowback water was properly stored, treated and disposed. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. In a November 18, 2011 report, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued 20 recommendations to federal agencies, states, and private entities that are intended to reduce the environmental impact and assure the safety of shale gas production.

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

Additionally, certain members of the Congress have called upon (a) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (b) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and (c) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Further, on August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA finalized rules under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA regulations include NSPS standards for completions of hydraulically-fractured gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions. After January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. We are currently evaluating the effect these regulations could have on our business. Compliance with such regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

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

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We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business.

Existing and potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

- the amounts and types of substances and materials that may be released into the environment;
- response to unexpected releases to the environment;
- reports and permits concerning exploration, drilling, production and other operations;
- the spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation

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

Further, changes to existing environmental regulations, or the adoption of new regulations, may unfavorably impact us, our suppliers or our customers. For example, governments around the world have become increasingly focused on regulating greenhouse gas (GHG) emissions in some manner. In the absence of federal regulation to address climate change, the U.S. EPA has taken action to regulate GHGs under the existing requirements of the Clean Air Act. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as from certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis, beginning in 2012 for emissions occurring in 2011. The new regulations could impact certain facilities in which we have interests (legal, equitable, operated or non-operated) by increasing the regulatory reporting requirements.

In December 2009, the EPA issued an endangerment finding concluding that the current and projected concentrations of GHGs in the atmosphere from motor vehicles threaten the public health and welfare of current and future generations. The finding required the EPA to regulate GHG emissions from new cars and light trucks under the Clean Air Act and to develop and apply relevant GHG permitting programs to large stationary sources. On January 2, 2011, the EPA initiated Prevention of Significant Deterioration (PSD) permitting requirements for carbon dioxide and other GHGs from large and modified stationary sources. Permits limiting GHGs have been issued for a variety of new or modified facilities under the Clean Air Act PSD program. GHG emissions also trigger Title V operating permit requirements for new and existing sources that exceed certain emission thresholds. The PSD permitting requirement is triggered when a new or modified facility emits specified levels of GHGs (e.g., 75,000-100,000 tons per year). Emission levels in excess of these thresholds can then trigger preconstruction permit requirements and application of best available control technology (BACT) as determined on a source-by-source basis. In most cases, based on cost, the BACT compliance option selected for GHGs is increased energy efficiency.

In addition, the U.S. Congress continues to consider adopting market or tax mechanisms to reduce emissions of GHG. Any such legislation or regulatory programs, depending on design and scope, could increase the cost of oil and gas production. Some states like California have already taken measures to reduce GHG emissions through a mixture of regulatory programs, including a low carbon fuel standard and cap and trade market.

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

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

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

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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 September 30, 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
July 1 - July 31, 2012	5,483	$ 30.40	—	—
August 1 - August 31, 2012	89,705	31.65	—	—
September 1 - September 30, 2012	3,476	32.32	—	—
Total	98,664	$ 31.61	—	—

(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))
4.1	Sixth Supplemental Indenture, dated as of July 3, 2012, to the Subordinated Indenture, dated as of December 10, 2001, between Newfield and U.S. Bank National Association (as successor to Wachovia Bank, National Association (formerly First Union National Bank)), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield's Current Report on Form 8-K filed with the SEC on July 3, 2012 (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 herewith.

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SIGNATURE

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

NEWFIELD EXPLORATION COMPANY

Date: October 29, 2012	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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