NEWFIELD EXPLORATION CO /DE/
Form 10-Q
October 21, 2011

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, 2011

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 19, 2011, there were 134,597,964 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, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 31	$ 39
Accounts receivable	322	354
Inventories	107	79
Derivative assets	170	197
Other current assets	78	62
Total current assets	708	731
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($2,346 and $1,658 were excluded from amortization at September 30, 2011 and December 31, 2010, respectively)	14,357	12,399
Less accumulated depreciation, depletion and amortization	(6,363)	(5,791)
Total property and equipment, net	7,994	6,608
Derivative assets	67	39
Long-term investments	50	48
Deferred taxes	29	29
Other assets	55	39
Total assets	$ 8,903	$ 7,494
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 97	$ 92
Accrued liabilities	747	670
Advances from joint owners	56	51
Asset retirement obligation	10	11
Derivative liabilities	6	53
Deferred taxes	57	51
Total current liabilities	973	928
Other liabilities	51	56
Derivative liabilities	1	46
Long-term debt	2,985	2,304
Asset retirement obligation	110	97
Deferred taxes	945	720
Total long-term liabilities	4,092	3,223
Commitments and contingencies (Note 12)	—	—
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, 2011 and December 31, 2010; 136,320,031 and 135,910,641 shares issued at September 30, 2011 and December 31, 2010, respectively)	1	1
Additional paid-in capital	1,482	1,450
Treasury stock (at cost, 1,721,720 and 1,664,538 shares at September 30, 2011 and December 31, 2010, respectively)	(51)	(41)
Accumulated other comprehensive loss	(10)	(12)
Retained earnings	2,416	1,945
Total stockholders' equity	3,838	3,343
Total liabilities and stockholders' equity	$ 8,903	$7,494

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Oil and gas revenues	$ 628	$ 449	$ 1,794	$ 1,355
Operating expenses:				
Lease operating	115	86	333	237
Production and other taxes	95	21	245	77
Depreciation, depletion and amortization	189	156	528	463
General and administrative	51	40	132	117
Other	—	—	—	10
Total operating expenses	450	303	1,238	904
Income from operations	178	146	556	451
Other income (expenses):				
Interest expense	(43)	(39)	(124)	(116)
Capitalized interest	24	15	61	43
Commodity derivative income	262	131	249	414
Other	3	1	2	2
Total other income	246	108	188	343
Income before income taxes	424	254	744	794
Income tax provision:				
Current	9	7	39	34
Deferred	146	86	234	259
Total income tax provision	155	93	273	293
Net income	$ 269	$ 161	$ 471	$ 501
Earnings per share:				
Basic	$ 2.00	$ 1.22	$ 3.52	$ 3.80
Diluted	$ 1.99	$ 1.20	$ 3.49	$ 3.75
Weighted-average number of shares outstanding for basic earnings per share	134	132	134	132
Weighted-average number of shares outstanding for diluted earnings per share	135	134	135	134

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, 2011	2010
Cash flows from operating activities:		
Net income	$471	$501
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	528	463
Deferred tax provision	234	259
Stock-based compensation	20	16
Commodity derivative income	(249)	(414)
Cash receipts on derivative settlements, net	156	345
Other non-cash charges	2	3
Changes in operating assets and liabilities:		
Decrease in accounts receivable	34	63
(Increase) decrease in inventories	(24)	3
(Increase) decrease in other current assets	(17)	49
Increase in other assets	(6)	(14)
Increase in accounts payable and accrued liabilities	24	26
Increase (decrease) in advances from joint owners	5	(1)
Increase (decrease) in other liabilities	(5)	8
Net cash provided by operating activities	1,173	1,307
Cash flows from investing activities:		
Additions to oil and gas properties	(1,723)	(1,191)
Acquisitions of oil and gas properties	(299)	(209)
Proceeds from sales of oil and gas properties	202	14
Additions to furniture, fixtures and equipment	(23)	(11)
Redemptions of investments	1	5
Net cash used in investing activities	(1,842)	(1,392)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	3,148	558
Repayments of borrowings under credit arrangements	(3,217)	(942)
Proceeds from issuance of senior subordinated notes	—	694
Proceeds from issuance of senior notes	750	—
Debt issue costs	(16)	(8)
Repayment of senior notes	—	(175)
Proceeds from issuances of common stock	12	22
Purchases of treasury stock, net	(16)	(14)
Net cash provided by financing activities	661	135
Increase (decrease) in cash and cash equivalents	(8)	50
Cash and cash equivalents, beginning of period	39	78

Cash and cash equivalents, end of period	$31	$128

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					
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2010	135.9	$ 1	(1.7)	$ (41)	$ 1,450	$ 1,945	$ (12)	$ 3,343
Issuances of common stock	0.4	—			12			12
Stock-based compensation					26			26
Treasury stock, net			—	(10)	(6)			(16)
Comprehensive income:								
Net income						471		471
Unrealized gain on investments, net of tax of $(1)							2	2
Total comprehensive income								473
Balance, September 30, 2011	136.3	$ 1	(1.7)	$ (51)	$ 1,482	$ 2,416	$ (10)	$ 3,838

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 oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma basins of the Mid-Continent, the Rocky Mountains, onshore Texas, Appalachia and the Gulf of Mexico. Internationally, we are active 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 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 state fairly 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, 2010.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil and gas. Historically, the energy markets have been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil or 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 gas reserves that we can economically produce.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from these estimates. Our most significant financial estimates are associated with our estimated proved oil and 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 of stockholders’ equity. 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 $0.3 million and $0.4 million for the three-month periods ended September 30, 2011 and 2010, respectively, and $1 million for each of the nine-month periods ended September 30, 2011 and 2010.

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 384,000 barrels and 277,000 barrels of crude oil valued at cost of $29 million and $15 million at September 30, 2011 and December 31, 2010, 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 $30 million and $17 million of internal costs during the three months ended September 30, 2011 and 2010, respectively, and $81 million and $53 million during the nine months ended September 30, 2011 and 2010, respectively. Interest expense related to unproved properties is also capitalized into oil and gas properties.

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

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using oil and gas reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials applicable to our reserves; plus
- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less
- related income tax effects.

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.

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

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At September 30, 2011, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $4.16 per MMBtu for natural gas and $94.48 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, 2011.

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

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

The change in our ARO for the nine months ended September 30, 2011 is set forth below (in millions):

Balance as of January 1, 2011	$	108
Accretion expense		8
Additions		9
Settlements		(5)
Balance at September 30, 2011		120
Less: Current portion of ARO at September 30, 2011		(10)
Total long-term ARO at September 30, 2011	$	110

Income Taxes

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

Derivative Financial Instruments

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

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note 5, "Derivative Financial Instruments," for a more detailed discussion of our derivative activities.

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New Accounting Requirements

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance was effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures, which were effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ended March 31, 2010, except for the Level 3 reconciliation disclosures, which we adopted for the quarter ended March 31, 2011. Adopting the disclosure requirements did not have a material impact on our financial position or results of operations.

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change will require 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. We do not expect adoption of the additional fair value measurement and disclosure requirements to have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance impacting the presentation of comprehensive income. The guidance eliminates the current option to report components of other comprehensive income in the statement of changes in equity. The guidance is intended to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the comprehensive income presentation to have an 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 (other than unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporate 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 11, “Stock-Based Compensation.”

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

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions, except per share data)			
Income (numerator):				
Net income — basic and diluted	$ 269	$ 161	$ 471	$ 501
Weighted-average shares (denominator):				
Weighted-average shares — basic	134	132	134	132
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period (1)	1	2	1	2
Weighted-average shares — diluted	135	134	135	134
Earnings per share:				
Basic	$ 2.00	$ 1.22	$ 3.52	$ 3.80
Diluted	$ 1.99	$ 1.20	$ 3.49	$ 3.75

(1) The calculation of shares outstanding for diluted EPS does not include the effect of one million unvested restricted stock and restricted stock units for each of the three and nine-month periods ended September 30, 2011 and 2010, respectively, because to do so would be anti-dilutive.

3. Comprehensive Income:

For the periods indicated, our comprehensive income consisted of the following:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)			
Net income	$ 269	$ 161	$ 471	$ 501
Unrealized gain (loss) on investments, net of tax of $1 and ($1) for the three and nine-month periods ended September 30, 2011, respectively, and net of tax of $1 for the nine-month period ended September 30, 2010	(2)	—	2	(2)
Total comprehensive income	$ 267	$ 161	$ 473	$ 499

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

4. Oil and Gas Assets:

Property and Equipment

As of the indicated dates, our property and equipment consisted of the following:

	September 30, 2011	December 31, 2010
	(In millions)	
Oil and gas properties:		
Subject to amortization	$11,874	$10,627
Not subject to amortization	2,346	1,658
Gross oil and gas properties	14,220	12,285
Accumulated depreciation, depletion and amortization	(6,293)	(5,730)
Net oil and gas properties	7,927	6,555
Other property and equipment	137	114
Accumulated depreciation and amortization	(70)	(61)
Net other property and equipment	67	53
Total property and equipment, net	$7,994	$6,608

The following is a summary of our oil and gas properties not subject to amortization as of September 30, 2011. 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, 2011, approximately 75% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

	Costs Incurred In				
	2011	2010	2009	2008 and prior	Total
			(In millions)		
Acquisition costs	$370	$357	$143	$464	$1,334
Exploration costs	450	78	61	67	656
Development costs	42	32	16	48	138
Fee mineral interests	—	—	—	23	23
Capitalized interest	61	58	51	25	195
Total oil and gas properties not subject to amortization	$923	$525	$271	$627	$2,346

Uinta Basin Asset Acquisitions

On May 17, 2011, we closed two previously announced transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $299 million. The assets include approximately 66,000 net acres, which are largely undeveloped and located north of our Greater Monument Butte field.

Other Asset Sales

During 2011, we sold certain non-strategic domestic assets for approximately $202 million. The cash flows and results of operations for the assets sold are included in our consolidated financial statements up to the date of sale.

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5. 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 revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions "Derivative assets" and "Derivative liabilities." Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model. Please see Note 8, "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 income under the caption "Commodity derivative income." 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, 2011, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu								
					Collars					Estimated Fair Value
		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 2011 – December 2011										
Price swap contracts	12,030	$6.03	—	—	—	—	—	—		$ 27
3-Way collar contracts	17,440	—	$4.50	$4.50	$5.50-$6.00	$5.86	$6.60-$8.03	$7.37		23
January 2012 – December 2012										
Price swap contracts	18,300	5.42	—	—	—	—	—	—		23
3-Way collar contracts	83,570	—	3.50-4.50	4.28	5.00-6.00	5.49	5.20-7.55	6.36		70
January 2013 – December 2013										
Price swap contracts	18,250	5.33	—	—	—	—	—	—		9
3-Way collar contracts	39,530	—	3.50-4.50	4.04	5.00-6.00	5.44	6.00- 7.55	6.48		21
										$ 173

Oil

Period and Type of Contract	Volume in MBbls	NYMEX Contract Price Per Bbl: Swaps (Weighted Average)	Additional Put: Range	Additional Put: Weighted Average	Collars: Floors: Range	Collars: Floors: Weighted Average	Collars: Ceilings: Range	Collars: Ceilings: Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
October 2011 – December 2011									
Price swap contracts	920	$81.51	—	—	—	—	—	—	$ 2
3-Way collar contracts	1,932	—	$60.00-$90.00	$66.90	$75.00-$100.00	$81.67	$102.25-$129.75	$111.68	10
January 2012 – December 2012									
3-Way collar contracts	12,810	—	55.00-90.00	66.86	75.00-100.00	82.96	88.20-137.80	111.14	37
January 2013 – December 2013									
3-Way collar contracts	4,745	—	55.00	55.00	80.00	80.00	109.50-111.40	110.54	20
									$ 69

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

Basis Contracts

At September 30, 2011, we had natural gas basis contracts that are not designated for hedge accounting to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points in the Rocky Mountains and Mid-Continent, as set forth in the table below.

	Rocky Mountains		Mid-Continent		Estimated
	Volume in MMMBtus	Weighted-Average Differential	Volume in MMMBtus	Weighted-Average Differential	Fair Value Asset (Liability) (In millions)
October 2011 – December 2011	1,320	$ (0.95)	4,290	$ (0.55)	$ (3)
January 2012 – December 2012	4,920	(0.91)	18,300	(0.55)	(9)
					$ (12)

Additional Disclosures about Derivative Instruments and Hedging Activities

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

Type of Contract	Balance Sheet Location	September 30, 2011	December 31, 2010
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Derivative assets – current	$ 130	$ 201
Oil contracts	Derivative assets – current	44	1
Basis contracts	Derivative assets – current	(4)	(5)
Natural gas contracts	Derivative assets – noncurrent	43	45
Oil contracts	Derivative assets – noncurrent	25	—
Basis contracts	Derivative assets – noncurrent	(1)	(6)
Oil contracts	Derivative liabilities – current	—	(53)
Basis contracts	Derivative liabilities – current	(6)	—
Natural gas contracts	Derivative liabilities – noncurrent	—	(4)
Oil contracts	Derivative liabilities – noncurrent	—	(42)
Basis contracts	Derivative liabilities – noncurrent	(1)	—
Total		$ 230	$ 137

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

The amount of gain (loss) recognized in income related to our derivative financial instruments is recorded under "Commodity derivative income" in our income statement, as follows:

Type of Contract	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)			
Derivatives not designated as hedging instruments:				
Realized gain on natural gas contracts	$68	$70	$198	$214
Realized gain (loss) on oil contracts	(5)	41	(37)	112
Realized loss on basis contracts	(2)	—	(5)	(3)
Total realized gain	61	111	156	323
Unrealized gain (loss) on natural gas contracts	5	111	(68)	191
Unrealized gain (loss) on oil contracts	197	(90)	162	(102)
Unrealized gain (loss) on basis contracts	(1)	(1)	(1)	2
Total unrealized gain	201	20	93	91
Total commodity derivative income	$262	$131	$249	$414

The total realized gain on commodity derivatives for the three and nine months ended September 30, 2010 differs from the cash receipts on derivative settlements due to the recognition of option premiums associated with derivatives settled during the period. There were no option premiums recognized during the three and nine months ended September 30, 2011.

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, 2011, Barclays Capital, Morgan Stanley, JPMorgan Chase Bank, N.A., Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to approximately 85% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

The counterparties to the majority of our derivative instruments also are lenders under our credit facility. Our credit facility, senior notes, senior subordinated notes and substantially all of our derivative instruments contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

6. Accounts Receivable:

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

	September 30, 2011	December 31, 2010
	(In millions)	
Revenue	$ 231	$ 199
Joint interest	77	133

Other	15	23
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$ 322	$ 354

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

7. Accrued Liabilities:

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

	September 30, 2011	December 31, 2010
	(In millions)	
Revenue payable	$80	$69
Accrued capital costs	369	327
Accrued lease operating expenses	75	54
Employee incentive expense	54	59
Accrued interest on debt	43	41
Taxes payable	106	81
Other	20	39
Total accrued liabilities	$747	$670

8. Fair Value Measurements:

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

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

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

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our valuation methodology for investments is a discounted cash flow model that considers various inputs including: (a) the coupon rate specified under the debt instruments, (b) the current credit ratings of the underlying issuers, (c) collateral characteristics and (d) risk adjusted discount rates. Level 3 instruments primarily include derivative instruments, such as basis swaps, commodity options including, price collars, floors and three-way collars (as of September 30, 2011, our options were comprised of only three-way collars) and some financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques, 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.

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

Fair Value of Investments and Derivative Instruments

The following tables summarize the valuation of our investments and financial instrument assets (liabilities) by pricing levels:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In millions)			
As of December 31, 2010:				
Investments available-for-sale:				
Equity securities	$7	$—	$ —	$7
Auction rate securities	—	—	30	30
Oil and gas derivative swap contracts	—	89	(11)	78
Oil and gas derivative option contracts	—	—	59	59
Total	$7	$89	$ 78	$174
As of September 30, 2011:				
Investments available-for-sale:				
Equity securities	$8	$—	$ —	$8
Auction rate securities	—	—	32	32
Oil and gas derivative swap contracts	—	61	(12)	49
Oil and gas derivative option contracts	—	—	181	181
Total	$8	$61	$ 201	$270

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, 2011, we continued to hold $32 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 $14 million ($9 million net of tax), recorded under the caption “Accumulated other comprehensive loss” on our consolidated balance sheet. As of December 31, 2010, we held $30 million of auction rate securities, which reflected a decrease in the fair value of $17 million ($11 million net of tax). The debt instruments underlying our auction rate securities are mostly investment grade (rated BBB+ or better) and are guaranteed by the United States government or backed by private loan collateral. We do not believe the decrease in the fair value of these securities is permanent because we currently intend to hold these investments until the auction succeeds, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

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

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

	Investments	Derivatives	Total
		(In millions)	
Balance at January 1, 2010	$40	$159	$199
Total realized or unrealized gains (losses):			
Included in earnings	—	74	74
Included in other comprehensive loss	(3)	—	(3)
Purchases, issuances and settlements	(5)	(108)	(113)
Transfers in and out of Level 3	—	—	—
Balance at September 30, 2010	$32	$125	$157
Change in unrealized gains included in earnings relating to investments and derivatives still held at September 30, 2010	$—	$87	$87
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 included in earnings relating to investments and derivatives still held at September 30, 2011	$—	$150	$150

Fair Value of Debt

The estimated fair value of our notes, based on quoted market prices as of the indicated dates, was as follows:

	September 30, 2011	December 31, 2010
	(In millions)	
6 % Senior Subordinated Notes due 2014	$ 327	$ 333
6 % Senior Subordinated Notes due 2016	557	568
7 % Senior Subordinated Notes due 2018	630	626
6 % Senior Subordinated Notes due 2020	735	733
5 ¾% Senior Notes due 2022	741	—

Amounts outstanding under our credit arrangements at September 30, 2011 and December 31, 2010 are stated at cost, which approximates fair value. Please see Note 9, "Debt."

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

9. Debt:

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

	September 30, 2011	December 31, 2010
	(In millions)	
Senior unsecured debt:		
Revolving credit facility LIBOR based loans	$50	$100
Money market lines of credit(1)	16	35
Total credit arrangements	66	135
5 ¾% Senior Notes due 2022	750	—
Total senior unsecured debt	816	135
6 % Senior Subordinated Notes due 2014	325	325
6 % Senior Subordinated Notes due 2016	550	550
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	694	694
Total long-term debt	$2,985	$2,304

(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

In June 2011, we entered into a new 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, 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, 2011, 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 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, 2011) 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, 2011).

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, 2011). We incurred aggregate commitment fees under our current and previous credit facilities of approximately $0.3 million and $1.2 million for the three and nine months ended September 30, 2011, respectively, which are recorded in interest expense on our consolidated statement of income. For the three and nine months ended September 30, 2010, we incurred aggregate commitment fees of approximately $0.6 million and $2 million, respectively.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns, and goodwill impairments) to interest expense of at least 3.0 to 1.0. At September 30, 2011, we were in compliance with all of our debt covenants.

Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at September 30, 2011). As of September 30, 2011, we had no letters of credit outstanding under our credit facility.

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

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $135 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

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

Senior Notes

On September 30, 2011, we sold $750 million of 5 ¾% Senior Notes due 2022 and received proceeds of approximately $743 million (net of discount and offering costs). These notes were issued at 99.956% of par to yield 5 ¾%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

10. Income Taxes:

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Amount computed using the statutory rate	$ 148	$ 89	$ 260	$ 278
Increase in taxes resulting from:				
State and local income taxes, net of federal effect	4	3	9	10
Net effect of different tax rates in non-U.S. jurisdictions	—	1	1	4
Other	3	—	3	1
Total provision for income taxes	$ 155	$ 93	$ 273	$ 293

As of September 30, 2011, we had net operating loss (NOL) carryforwards for international income tax purposes of approximately $17 million. We currently estimate that we will not be able to utilize $17 million of our international NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, valuation allowances were established for these items in 2005 and 2006. Estimates of future taxable income can be significantly affected by changes in oil and gas prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

As of September 30, 2011, we did not have a liability for uncertain tax positions and, as such, had not accrued related interest or penalties. The tax years 2008-2010 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

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

11. Stock-Based Compensation:

On May 5, 2011, at our 2011 annual meeting of stockholders, our stockholders approved the Newfield Exploration Company 2011 Omnibus Stock Plan (the 2011 Omnibus Stock Plan), and our 2009 Omnibus Stock Plan and 2009 Non-Employee Director Restricted Stock Plan were terminated such that no new grants will be made under the previous plans. All stock-based compensation equity awards to employees and non-employee directors will be granted under the 2011 Omnibus Stock Plan. Outstanding awards under those previous plans were not impacted by the termination of those previous plans. The fair value of grants is determined utilizing the Black-Scholes option pricing model for stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units. In February 2011, we also granted cash-settled restricted stock units to employees that were not issued under any of our plans as they will be settled in cash upon vesting and are accounted for as liability awards.

As of the indicated dates, our stock-based compensation for our equity and liability awards consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Total stock-based compensation	$ 9	$ 6	$ 28	$ 24
Capitalized in oil and gas properties	(3)	(2)	(8)	(8)
Net stock-based compensation expense	$ 6	$ 4	$ 20	$ 16

As of September 30, 2011, we had approximately $88 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation equity awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting period. The full amount is expected to be recognized within approximately five years.

Stock Options. The following table provides information about stock option activity for the nine months ended September 30, 2011:

	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, 2010	1.5	$34.58		4.7	$58
Granted	—	—	$—		
Exercised	(0.4)	30.04			17
Forfeited	—	—			
Outstanding at September 30, 2011	1.1	$35.86		4.2	$8
Exercisable at September 30, 2011	1.0	$33.83		3.8	$8

(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, 2011, the last reported sales price of our common stock on the New York Stock Exchange was $39.69 per share.

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

Restricted Stock. The following table provides information about equity-classified restricted stock and restricted stock unit activity for the nine months ended September 30, 2011:

	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, 2010	2.2	0.3	2.5	$36.84
Granted	0.9	0.1	1.0	66.69
Forfeited	(0.2)	—	(0.2)	43.86
Vested	(0.8)	(0.1)	(0.9)	34.71
Non-vested shares outstanding at September 30, 2011	2.1	0.3	2.4	$49.64

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. As of September 30, 2011, 132,920 cash-settled restricted stock 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 2011, options to purchase 34,073 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $17.13 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 0.19%, an expected life of six months and weighted-average volatility of 31%.

On July 1, 2011, options to purchase 37,236 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $16.83 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 0.10%, an expected life of six months and weighted-average volatility of 33%.

12. Commitments and Contingencies:

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (1) claims from royalty owners for disputed royalty payments, (2) commercial disputes, (3) personal injury claims and (4) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

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

13. 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, China and Other International. The accounting policies of each of our operating segments are the same as those described in Note 1, "Organization and Summary of Significant Accounting Policies."

The following tables provide the geographic operating segment information for the three and nine months ended September 30, 2011 and 2010. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

Three Months Ended September 30, 2011:

	Domestic	Malaysia	China	Other International	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 taxes	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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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS-(Continued)

Three Months Ended September 30, 2010:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Oil and gas revenues	$357	$80	$12	$—	$449
Operating expenses:					
Lease operating	68	17	1	—	86
Production and other taxes	2	17	2	—	21
Depreciation, depletion and amortization	128	24	4	—	156
General and administrative	39	1	—	—	40
Allocated income taxes	44	8	2	—	
Net income from oil and gas properties	$76	$13	$3	$—	
Total operating expenses					303
Income from operations					146
Interest expense, net of interest income, capitalized interest and other					(23)
Commodity derivative income					131
Income before income taxes					$254
Total assets	$6,420	$604	$202	$—	$7,226
Additions to long-lived assets	$364	$18	$8	$—	$390

Nine Months Ended September 30, 2011:

	Domestic	Malaysia	China	Other International	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 taxes	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

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

Nine Months Ended September 30, 2010:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Oil and gas revenues	$1,055	$259	$41	$—	$1,355
Operating expenses:					
Lease operating	195	39	3	—	237
Production and other taxes	33	38	6	—	77
Depreciation, depletion and amortization	371	78	11	3	463
General and administrative	113	3	1	—	117
Other	10	—	—	—	10
Allocated income taxes	124	39	6	(1)	
Net income (loss) from oil and gas properties	$209	$62	$14	$(2)	
Total operating expenses					904
Income from operations					451
Interest expense, net of interest income, capitalized interest and other					(71)
Commodity derivative income					414
Income before income taxes					$794
Total assets	$6,420	$604	$202	$—	$7,226
Additions to long-lived assets	$1,280	$99	$33	$—	$1,412

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

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma basins of the Mid-Continent, the Rocky Mountains, onshore Texas, Appalachia and the Gulf of Mexico. Internationally, we are active in Malaysia and China.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flow available for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of oil and gas that we can economically produce; and
- the accounting for our oil and gas activities including among other items, the determination of ceiling test writedowns.

Any extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. Please see the discussion under "Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and may in the future result in additional ceiling test writedowns or other impairments" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010 and "— Liquidity and Capital Resources" below.

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production. 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.

Reserve Replacement. To maintain and grow our production and cash flow, we must continue to develop existing reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves.

Significant Estimates. We believe the most difficult, subjective or complex judgments and estimates we must make in connection with the preparation of our financial statements are:

- the quantity of our proved oil and gas reserves;
- the timing of future drilling, development and abandonment activities;
- the cost of these activities in the future;
- the fair value of the assets and liabilities of acquired companies;

- the fair value of our financial instruments including derivative positions; and
- the fair value of stock-based compensation.

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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 with changes in fair value reported in current earnings, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of September 30, 2011, we had net derivative assets of $230 million, of which 74% 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, 2011. 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" below and Note 5, "Derivative Financial Instruments," and Note 8, "Fair Value Measurements," to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Other Factors. Please see "Risk Factors" in Item 1A below and in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010 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.

Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production and do not include the effects of the settlements of our hedges. Please see Note 5, "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, crude oil from our operations offshore Malaysia and China is produced into FPSOs and "lifted" and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into the FPSO. As a result, the timing of liftings may impact period-to-period results.

Revenues of $628 million for the third quarter of 2011 were 40% higher than the comparable period of 2010. Revenues of $1.8 billion for the first nine months of 2011 were 32% higher than the comparable period of 2010. Approximately half of the increase in revenues in both periods is due to higher average realized oil prices and the other half of the increase resulted from higher oil production.

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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, 2011 and 2010.

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Percentage Increase (Decrease)	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Percentage Increase (Decrease)
Production:(1)(2)						
Domestic:						
Natural gas (Bcf)	43.8	46.6	(6) %	132.8	138.8	(4) %
Oil, condensate and NGLs (MBbls)	3,392	2,645	28 %	9,407	7,326	28 %
Total (Bcfe)	64.2	62.5	3 %	189.3	182.8	4 %
International:						
Natural gas (Bcf)	—	—	—	—	—	—
Oil, condensate and NGLs (MBbls)	1,678	1,279	31 %	4,397	4,172	5 %
Total (Bcfe)	10.1	7.7	31 %	26.4	25.0	5 %
Total:						
Natural gas (Bcf)	43.8	46.6	(6) %	132.8	138.8	(4) %
Oil, condensate and NGLs (MBbls)	5,070	3,924	29 %	13,804	11,498	20 %
Total (Bcfe)	74.3	70.2	6 %	215.7	207.8	4 %
Average Realized Prices:(2)(3)						
Domestic:						
Natural gas (per Mcf)	$ 4.22	$ 4.14	2 %	$ 4.21	$ 4.25	(1) %
Oil, condensate and NGLs (MBbls)	75.99	61.37	24 %	79.63	62.88	27 %
Natural gas equivalent (per Mcfe)	6.92	5.71	21 %	6.94	5.77	20 %
International:						
Natural gas (per Mcf)	$ —	$ —	—	$ —	$ —	—
Oil, condensate and NGLs (MBbls)	109.62	72.04	52 %	109.31	71.83	52 %
Natural gas equivalent (per Mcfe)	18.27	12.01	52 %	18.22	11.97	52 %
Total:						
Natural gas (per Mcf)	$ 4.22	$ 4.14	2 %	$ 4.21	$ 4.25	(1) %
Oil, condensate and NGLs (MBbls)	87.12	64.85	34 %	89.09	66.13	35 %
Natural gas equivalent (per Mcfe)	8.46	6.40	32 %	8.32	6.52	28 %

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in our operations of 1.6 Bcfe and 1.1 Bcfe during the three months ended September 30, 2011 and 2010, respectively, and 4.9 Bcfe and 3.4 Bcfe during the nine months ended September 30, 2011 and 2010, respectively.

(2) Historically, we reported natural gas liquids (NGLs) volumes in natural gas production volumes. Effective January 1, 2011, we began reporting our NGLs in barrels and including NGLs with total oil and condensate

production. As such, all production volumes and average realized prices for periods prior to 2011 have been reclassified for comparability between periods.

(3) Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been $5.72 and $5.63 per Mcf for the three months ended September 30, 2011 and 2010, respectively, and $5.67 and $5.77 per Mcf for the nine months ended September 30, 2011 and 2010, respectively. Our total oil and condensate average realized price would have been $86.16 and $75.42 per Bbl for the three months ended September 30, 2011 and 2010, respectively, and $86.38 and $75.87 per Bbl for the nine months ended September 30, 2011 and 2010, respectively.

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Domestic Production. Our domestic oil and gas production for the three months ended September 30, 2011, stated on a natural gas equivalent basis, increased over the comparable period of 2010 primarily due to increases in production of 17% and 7% as a result of continued successful development drilling efforts in our Rocky Mountain and Mid-Continent divisions, respectively. These increases were partially offset by production declines of 12% and 16% in our onshore Gulf Coast and Gulf of Mexico deepwater divisions, respectively, due to natural field declines and weather-related delays.

Our domestic oil and gas production for the nine months ended September 30, 2011, stated on a natural gas equivalent basis, increased over the comparable period of 2010 primarily due to increased production of 17% in our Rocky Mountain division as a result of continued successful development drilling efforts, partially offset by a 12% decline in our onshore Gulf Coast division production.

International Production. Our international oil production for the three and nine months ended September 30, 2011, stated on a natural gas equivalent basis, increased over the comparable periods of 2010 primarily due to the timing of liftings in Malaysia. Production during the three months ended September 30, 2010 from our operations in Malaysia was impacted by approximately 334 MBbls of deferred production related to a damaged export pipeline.

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, 2011 and 2010.

	Unit-of-Production			Total Amount		
	Three Months Ended September 30,		Percentage Increase (Decrease)	Three Months Ended September 30,		Percentage Increase (Decrease)
	2011	2010		2011	2010	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$1.45	$1.09	33 %	$93	$68	37 %
Production and other taxes	0.29	0.04	625 %	19	2	722 %
Depreciation, depletion and amortization	2.40	2.06	17 %	154	128	20 %
General and administrative	0.76	0.62	23 %	49	39	27 %
Total operating expenses	4.91	3.80	29 %	315	237	33 %
International:						
Lease operating	$2.18	$2.28	(4)%	$22	$18	25 %
Production and other taxes	7.63	2.48	208 %	76	19	304 %
Depreciation, depletion and amortization	3.49	3.64	(4)%	35	28	26 %
General and administrative	0.14	0.14	—	2	1	38 %
Total operating expenses	13.44	8.53	58 %	135	66	107 %
Total:						
Lease operating	$1.55	$1.22	27 %	$115	$86	34 %
Production and other taxes	1.28	0.30	327 %	95	21	348 %
Depreciation, depletion and amortization	2.55	2.23	14 %	189	156	21 %
General and administrative	0.68	0.56	21 %	51	40	28 %
Total operating expenses	6.06	4.32	40 %	450	303	49 %

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Domestic Operations. Our domestic operating expenses for the three months ended September 30, 2011, stated on a Mcfe basis, increased 29% over the same period of 2010. The components of the significant period-to-period change are as follows:

- Lease operating expenses (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. The increase in total domestic LOE per Mcfe resulted from a 57% increase in the recurring portion of our LOE coupled with a slight increase in production volumes. Increased water handling and overall operations and service-related costs in our Rocky Mountain division accounted for approximately 70% of the increase.

- Production and other taxes per Mcfe increased due to a 24% increase in realized oil prices during 2011, coupled with a 32% increase in 2011 oil, condensate and NGL production that is subject to production taxes, as compared to the same period of 2010. In addition, we recorded refunds of $4 million ($0.06 per Mcfe) during the third quarter of 2011 related to production tax exemptions on some of our onshore wells, whereas we recorded similar refunds of $15 million ($0.24 per Mcfe) during the same period of 2010.

- Since late 2009, the shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our depreciation, depletion and amortization (DD&A) rate. The increase in total DD&A expense is related to the increase in the DD&A rate, coupled with the 3% increase in our production volumes during the third quarter of 2011 compared to the same period of 2010.

- General and administrative (G&A) expense per Mcfe increased due to employee-related expenses associated with our growing domestic work force and approximately $5 million of legal expenses related to litigation in which we are the plaintiff. During the third quarter of 2011, we capitalized $21 million of direct internal costs as compared to $13 million during the third quarter of 2010.

International Operations. Our international operating expenses for the three months ended September 30, 2011, stated on a Mcfe basis, increased 58% over the same period of 2010. The components of the significant period-to-period change are as follows:

- The slight decrease in LOE per Mcfe is due to fixed production and operating costs associated with certain of our production sharing contracts (PSCs) in Malaysia and a change in the mix of produced, lifted and sold production from the various PSCs during the third quarter of 2011 compared to the same period of 2010, partially offset by increased non-recurring pipeline and facilities repair related activities in the third quarter of 2011.

- Production and other taxes per Mcfe increased significantly due to an increase, per the terms of the PSCs, in the tax rate per barrel of oil lifted and sold as a result of substantially higher realized oil prices during the third quarter of 2011.

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The following table presents information about our operating expenses for the nine months ended September 30, 2011 and 2010.

	Unit-of-Production Nine Months Ended September 30, 2011 (Per Mcfe)	2010	Percentage Increase (Decrease)	Total Amount Nine Months Ended September 30, 2011 (In millions)	2010	Percentage Increase (Decrease)
Domestic:						
Lease operating	$1.38	$1.07	29 %	$260	$195	33 %
Production and other taxes	0.30	0.18	67 %	56	33	71 %
Depreciation, depletion and amortization	2.33	2.03	15 %	440	371	19 %
General and administrative	0.68	0.62	10 %	128	113	14 %
Other	—	0.05	(100)%	—	10	(100)%
Total operating expenses	4.67	3.95	18 %	884	722	23 %
International:						
Lease operating	$2.75	$1.66	66 %	$73	$42	74 %
Production and other taxes	7.17	1.77	305 %	189	44	326 %
Depreciation, depletion and amortization	3.35	3.69	(9)%	88	92	(4)%
General and administrative	0.15	0.18	(17)%	4	4	(13)%
Total operating expenses	13.41	7.30	84 %	354	182	94 %
Total:						
Lease operating	$1.54	$1.14	35 %	$333	$237	40 %
Production and other taxes	1.14	0.37	208 %	245	77	218 %
Depreciation, depletion and amortization	2.45	2.23	10 %	528	463	14 %
General and administrative	0.61	0.56	9 %	132	117	13 %
Other	—	0.05	(100)%	—	10	(100)%
Total operating expenses	5.74	4.35	32 %	1,238	904	37 %

Domestic Operations. Our domestic operating expenses for the nine months ended September 30, 2011, stated on a Mcfe basis, increased 18% over the same period of 2010. The components of the significant period-to-period change are as follows:

- The increase in total domestic LOE per Mcfe resulted from a 50% increase in the recurring portion of our LOE coupled with a slight increase in production volumes. Increased water handling and overall operations and service-related costs in our Rocky Mountain division accounted for approximately 55% of the increase in our recurring LOE.

- Production and other taxes per Mcfe increased due to a 27% increase in realized oil prices during 2011, coupled with a 33% increase in 2011 oil, condensate and NGL production that is subject to production taxes, as compared to the same period of 2010. In addition, we received refunds of $16 million ($0.08 per Mcfe) during first nine months of 2011 related to production tax exemptions on some of our onshore wells, whereas we received similar refunds of $22 million ($0.12 per Mcfe) during the same period of 2010.

- Since late 2009, the shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our DD&A rate. The increase in total DD&A expense is related to the increase in the DD&A rate, coupled with the 4% increase in our production volumes during the first nine months of 2011 compared to the same period of 2010.

- G&A expense per Mcfe increased due to employee-related expenses associated with our growing domestic work force and approximately $5 million of legal expenses related to litigation in which we are the plaintiff. During the nine months ended September 30, 2011, we capitalized $59 million of direct internal costs as compared to $40 million in the same period of 2010.

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International Operations. Our international operating expenses for the nine months ended September 30, 2011, stated on a Mcfe basis, increased 84% over the same period of 2010. The components of the significant period-to-period change are as follows:

- LOE per Mcfe increased due to non-recurring pipeline and facilities repair related activities in Malaysia, fixed production costs associated with certain of our PSCs in Malaysia and a change in the mix of produced, lifted and sold production from the various PSCs during the first nine months of 2011 compared to the same period of 2010.

- Production and other taxes per Mcfe increased significantly due to an increase, per the terms of the PSCs, in the tax rate per barrel of oil lifted and sold as a result of substantially higher realized oil prices during the first nine months of 2011.

Commodity Derivative Income. The significant fluctuations in commodity derivative income from period to period is due to the significant volatility of oil and 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,	
	2011	2010	2011	2010
	(In millions)			
Gross interest expense:				
Credit arrangements	$5	$—	$9	$1
Senior notes	—	—	—	2
Senior subordinated notes	38	38	114	111
Other	—	1	1	2
Total gross interest expense	43	39	124	116
Capitalized interest	(24)	(15)	(61)	(43)
Net interest expense	$19	$24	$63	$73

Net interest expense decreased $5 million and $10 million for the three and nine months ended September 30, 2011, respectively, as compared to the same period of 2010 primarily due to an increase in capitalized interest, partially offset by an increase in interest expense as a result of increased borrowings under our credit arrangements. Interest expense related to unproved properties is capitalized into oil and gas properties. Capitalized interest increased in 2011 as compared to the same periods of 2010 due to an increase in the average balance of unproved properties.

Taxes. The effective tax rate for both the third quarter of 2011 and 2010 was 37%. The effective tax rates for the first nine months of both 2011 and 2010 were 37%. Our effective tax rate generally approximates 37%.

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

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow our production and cash flow. We accomplish this through successful drilling programs and the acquisition of properties. These activities require substantial capital expenditures. Lower prices for oil and 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 cash flows from operations. Approximately 84% of our expected 2011 domestic oil and gas production supporting the current 2011 capital budget estimate is hedged. Our 2011 capital budget, excluding capitalized interest and overhead of $172 million, is approximately $1.9 billion and focuses on projects we believe will generate and lay the foundation for oil production growth in 2011 and thereafter. Approximately two-thirds of the 2011 budget is allocated to oil projects and substantially all the remainder is planned for “liquids rich” gas plays.

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Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

In May 2011, we closed two previously announced transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $299 million. The acquisitions were funded with borrowings under our credit facility. During the first nine months of 2011, we received proceeds from the sale of certain non-strategic properties of approximately $202 million. We used the proceeds from these sales to reduce borrowings outstanding under our credit facility. We are continuing to market and sell other certain non-strategic domestic assets and expect proceeds for such sales during the fourth quarter 2011 to be approximately $200 to $350 million. As a result, we expect to substantially fund our $1.9 billion 2011 capital program with the proceeds from asset sales during the year and cash flows from operations.

On September 30, 2011, we sold $750 million of 5 ¾% Senior Notes due 2022 and received proceeds of $743 million (net of discount and offering costs). These notes were issued at 99.956% of par to yield 5 ¾%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

We continue to hold auction rate securities with a fair value of $32 million. We attempt to sell these securities every 7-28 days until the auctions succeed, the issuer calls the securities or the securities mature. We currently do not believe that the decrease in the fair value of these investments is permanent or that the failure of the auction mechanism will have a material impact on our liquidity given the amount of our available borrowing capacity under our credit arrangements. See Note 8, “Fair Value Measurements,” for more information regarding the auction rate securities.

Credit Arrangements. In June 2011, we entered into a new 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, as agent. As of September 30, 2011, the largest individual commitment was 13% of total commitments.

In addition, subject to compliance with covenants in our credit facility that restrict our ability to incur additional debt, we also have a total of $135 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 9, “Debt,” to our consolidated financial statements appearing earlier in this report.

At October 19, 2011, we had no letters of credit outstanding under our credit facility. We had outstanding borrowings of $115 million under our credit facility and $127 million under our money market lines of credit. Our available borrowing capacity under our credit arrangements was approximately $1.1 billion as of October 19, 2011.

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. 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, 2011, we had negative working capital of $265 million compared to negative working capital of $197 million at December 31, 2010. The decrease in our working capital as compared to December 31, 2010 is 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 contributed to the change.

Cash Flows from Operations. Cash flows from operations are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We sell substantially all of our oil and gas production under floating price market sensitive contracts. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months. See "—Oil and Gas Hedging" below.

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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 $1.2 billion for the nine months ended September 30, 2011, a decrease of $134 million compared to net cash flows from operations of $1.3 billion for the same period in 2010. The decrease results from changes in our working capital requirements 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 a decrease 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, 2011 was $1.8 billion compared to $1.4 billion for the same period in 2010.

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

- spent $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.

During the nine months ended September 30, 2010, we:

- spent $1.4 billion (including $209 million for acquisitions of oil and gas properties);
- received proceeds of $14 million from sales of oil and gas properties; and
- redeemed investments of $5 million.

Capital Expenditures. Our capital investments of $1.8 billion for the first nine months of 2011 increased 51% from our capital investments of $1.2 billion during the same period of 2010. These amounts exclude acquisitions of $299 million and $211 million in the 2011 and 2010 periods, respectively, and recorded asset retirement obligations of $9 million and $8 million in the respective periods. Of the total $2.1 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), $416 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $249 million outside the United States. Of the total $1.4 billion spent during the first nine months of 2010, we invested $846 million in domestic exploitation and development, $157 million in domestic exploration (exclusive of exploitation and leasehold activity), $262 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $128 million outside the United States.

We have budgeted $1.9 billion for capital spending in 2011. The planned budget excludes capitalized interest and overhead of $172 million and acquisitions. Approximately two-thirds of the 2011 budget is allocated to oil projects and substantially all of the remainder is planned for “liquids rich” gas plays. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

In May 2011, we closed two previously announced transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $299 million. The assets include approximately 66,000 net acres, which are largely undeveloped and located north of our Greater Monument Butte field.

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Cash Flows from Financing Activities. Net cash flows provided by financing activities for the nine months ended September 30, 2011 were $661 million compared to $135 million for the same period in 2010.

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 5 ¾% Senior Notes due 2022 at 99.956% of par and paid $8 million in associated debt issue costs;
- paid $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.

During the nine months ended September 30, 2010, we:

- borrowed $558 million and repaid $942 million under our credit arrangements;
- issued $700 million aggregate principal amount of our 6 % Senior Subordinated Notes due 2020 at 99.109% of par and paid $8 million in associated debt issue costs;
- repaid our $175 million aggregate principal amount 7 % Senior Notes due 2011;
- received proceeds of $22 million from the issuance of shares of our common stock upon the exercise of stock options; and
- repurchased $14 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

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, 2010.

Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and gas prices. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions.

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues 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, 2011, Barclays Capital, Morgan Stanley, JPMorgan Chase Bank, Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to approximately 85% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

A significant number of the counterparties to our hedging arrangements also are lenders under our credit facility. Our credit facility, senior notes, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations.

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

The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.25-$0.50 per MMBtu less than the Henry Hub Index. Realized natural gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 90-95% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 6 Bcf of our natural gas production from October 2011 through December 2012 to lock in the differential at a weighted average of $0.92 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 hedged basis associated with approximately 22 Bcf of our anticipated natural gas production from the Stiles/Britt Ranch area for the period October 2011 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 105-110% 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 $15-$17 per barrel below the WTI price. Oil production from our Mid-Continent properties, excluding NGLs, typically averages 90-95% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 120-125% of WTI. Oil sales from our operations in China typically sell at $23-$28 per barrel greater than the WTI price.

Please see the discussion and tables in Note 5, “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, 2011 and the estimated fair market value of those contracts as of that date.

New Accounting Requirements

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance was effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures, which were effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ended March 31, 2010, except for the Level 3 reconciliation disclosures, which we adopted for the quarter ended March 31, 2011. Adopting the disclosure requirements did not have a material impact on our financial position or results of operations.

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change will require 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. We do not expect adoption of the additional fair value measurement and disclosure requirements to have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance impacting the presentation of comprehensive income. The guidance eliminates the current option to report components of other comprehensive income in the statement of changes in equity. The guidance is intended to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the comprehensive income presentation to have an impact on our financial position or results of operations.

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General Information

General information about us can be found at www.newfield.com. In conjunction with our web page, we also maintain an electronic publication entitled @NFX. @NFX is periodically published to provide updates on our operating activities and our latest publicly announced estimates of expected production volumes, costs and expenses for the then current quarter. Recent editions of @NFX are available on our web page. To receive @NFX directly by email, please forward your email address to info@newfield.com or visit our web page and sign up. Unless specifically incorporated, the information about us at www.newfield.com or in any edition of @NFX is not part of this report.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission.

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. 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 gas prices;
- general economic, financial, industry or business 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 transportations and refining capacity for the crude oil we produce in the Uinta Basin;
- drilling results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- labor conditions;
- weather conditions, and changes in weather patterns, including adverse conditions and changes in patterns due to climate change;

- environmental liabilities that are not covered by an effective indemnity or insurance;
- changes in tax rates;
- 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 other factors affecting our business described under the caption “Risk Factors” below and under Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010.

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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 and in our Annual Report on Form 10-K for the year ended December 31, 2010. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

Commonly Used Oil and Gas Terms

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

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

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

Bcf. Billion cubic feet.

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

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

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

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

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

Mcf. One thousand cubic feet.

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

MMBtu. One million Btus.

MMMBtu. One billion Btus.

NYMEX. The New York Mercantile Exchange.

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

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

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Oil and Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-24 months as part of our risk management program. 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. We use hedging to reduce our exposure to fluctuations in oil and gas prices. 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 hedging limits the downside risk of adverse price movements, it also may limit future revenues from favorable price movements. 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 5, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report.

Interest Rates

At September 30, 2011, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility and money market lines of credit	$—	$66
5 ¾% Senior Notes due 2022	750	—
6 % Senior Subordinated Notes due 2014	325	—
6 % Senior Subordinated Notes due 2016	550	—
7 % Senior Subordinated Notes due 2018	600	—
6 % Senior Subordinated Notes due 2020	694	—
Total debt	$2,919	$66

We consider our interest rate exposure to be minimal because approximately 98% of our obligations were at fixed rates. Our variable rate debt is currently at interest rates of 2% or less.

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 flow, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at September 30, 2011.

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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, 2011.

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 2011 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

There have been no material changes with respect to the legal proceedings previously reported in our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 1A. Risk Factors

The following risk factors update and should be considered in addition to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

There is limited transportation and refining capacity for our black and yellow wax crude oil, which may limit our ability to sell our current production or to increase our production in the Uinta Basin.

Most of the crude oil we produce in the Uinta Basin is known as “black wax” or “yellow wax” because it has higher paraffin content than crude oil found in most other major North American basins. Due to its wax content, it must remain heated during shipping, so our transportation options are limited. Currently, the oil is transported by truck to refiners in the Salt Lake City area. We currently have agreements in place with area refiners that secure base load sales of substantially all of our expected production in the Uinta Basin through the end of 2012. An extended loss of any of our largest purchasers could have a material adverse effect on us because there are limited purchasers of our black and yellow wax crude. We continue to work with refiners to expand the market for our existing wax crude oil production and to secure additional capacity to allow for production growth. However, without additional refining capacity, our ability to increase production from the field may be limited.

We are subject to complex laws and regulatory actions that can affect the cost, manner or feasibility 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. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, changes to existing 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 climate change matters. In December 2009, the EPA issued a final rule that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change. This finding allowed the EPA to proceed with the rulemaking process to regulate greenhouse gases under the Clean Air Act. The EPA has adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011, which could require greenhouse emission controls for those sources. The EPA has also 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 addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas that is produced.

Further, the U.S. Congress has previously proposed legislation that would directly impact our industry, covering areas such as emission reporting and reductions, and the regulation of over-the-counter commodity hedging activities. Similarly, 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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The potential adoption of federal and state 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 90% of our probable reserves at year-end 2010. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural-gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which we operate, including Colorado, Pennsylvania, Texas and Wyoming, 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. 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, 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.

There are certain governmental reviews either underway or 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. 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 is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Additionally, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission 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 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 mechanism.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently researching the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than February 28, 2012.

Increased regulation and attention given to the hydraulic fracturing process 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, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

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Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

On September 12, 2011, President Obama sent to Congress a legislative package that includes proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals:

- the repeal of the percentage depletion allowance for oil and natural gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. It is unclear whether these or similar changes will be enacted. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The oil and gas business involves many operating risks that can cause substantial losses.

Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the risk of:

- fires and explosions;
- blow-outs;
- uncontrollable or unknown flows of oil, gas, or well fluids;
- pipe or cement failures and casing collapses;
- pipeline ruptures;
- adverse weather conditions or natural disasters;
- discharges of toxic gases;
- build up of naturally occurring radioactive materials;
- vandalism; and
- environmental damages caused by previous owners of property we purchase and lease.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;

- severe damage or destruction of property and equipment, and oil and gas reservoirs;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties or lawsuits;
- suspension of our operations; and
- repairs to resume operations.

Further, offshore and deepwater operations are subject to a variety of additional operating risks, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions could cause substantial damage to facilities and interrupt production. In addition, some of our offshore operations, and most of our deepwater and international operations, are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities that we do not own. Necessary infrastructures have been in the past, and may be in the future, temporarily unavailable due to adverse weather conditions or other reasons, or they may not be available to us in the future on acceptable terms or at all.

In connection with our operations, we generally require our contractors, which includes the contractor, its parent, subsidiaries and affiliate companies, its subcontractors, their agents, employees, directors and officers, to agree to indemnify us for injuries and deaths of their employees, contractors and subcontractors and any property damage suffered by the contractors. There may be times, however, that we are required to indemnify our contractors for injuries and other losses resulting from the events described above, which indemnification claims could result in substantial losses to us.

The occurrence of any of the foregoing events and any costs or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage or not indemnified, could reduce revenue and the funds available to us for our exploration, exploitation, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations. See also " We may not be insured against all of the operating risks to which our business is exposed."

We may not be insured against all of the operating risks to which our business is exposed.

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, such as well blowouts, explosions, oil spills, releases of gas or well fluids, fires, pollution and adverse weather conditions, which could result in substantial losses to us. See also " The oil and gas business involves many operating risks that can cause substantial losses." We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our insurance coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our onshore and offshore operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. For example, we maintain operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

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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, 2011.

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, 2011	8,770	$ 68.12	—	—
August 1 - August 31, 2011	5,800	67.64	—	—
September 1 - September 30, 2011	4,180	51.11	—	—
Total	18,750	$ 64.18	—	—

(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	Second 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, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield's Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield's Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Elimination of Series A Junior Participating Preferred Stock, dated August 8, 2011 (incorporated by reference to Exhibit 3.1 to Newfield's Current Report on Form 8-K filed with the SEC on August 9, 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	Second Supplemental Indenture, dated as of September 30, 2011, between the Company 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 4.2 to Newfield's Current Report on Form 8-K filed with the SEC on September 30, 2011 (File No. 1-12534))
*10.1	Credit Agreement, dated as of June 2, 2011, by and among Newfield Exploration Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, and BBVA Compass, The Bank of Tokyo-Mitsubishi UFJ, Ltd., and DNB Nor Bank ASA, as Co-Documentation Agents, and other Lenders thereto
*10.2	First Amendment to Credit Agreement, dated as of September 27, 2011, by and among Newfield Exploration Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, and BBVA Compass, The Bank of Tokyo-Mitsubishi UFJ, Ltd., and DNB Nor Bank ASA, as Co-Documentation Agents, and other Lenders thereto
*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
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*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 21, 2011	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer (Principal Financial Officer)

Exhibit Index

Exhibit Number	Description
3.1	Second 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, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield's Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield's Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Elimination of Series A Junior Participating Preferred Stock, dated August 8, 2011 (incorporated by reference to Exhibit 3.1 to Newfield's Current Report on Form 8-K filed with the SEC on August 9, 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	Second Supplemental Indenture, dated as of September 30, 2011, between the Company 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 4.2 to Newfield's Current Report on Form 8-K filed with the SEC on September 30, 2011 (File No. 1-12534))
*10.1	Credit Agreement, dated as of June 2, 2011, by and among Newfield Exploration Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, and BBVA Compass, The Bank of Tokyo-Mitsubishi UFJ, Ltd., and DNB Nor Bank ASA, as Co-Documentation Agents, and other Lenders thereto
*10.2	First Amendment to Credit Agreement, dated as of September 27, 2011, by and among Newfield Exploration Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, and BBVA Compass, The Bank of Tokyo-Mitsubishi UFJ, Ltd., and DNB Nor Bank ASA, as Co-Documentation Agents, and other Lenders thereto
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