NEWFIELD EXPLORATION CO /DE/
Form 10-Q
April 30, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2010

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)

363 North Sam Houston Parkway East
Suite 100
Houston, Texas 77060
(Address and Zip Code of principal executive offices)

(281) 847-6000
(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	Smaller reporting company o
	(Do not check if a smaller reporting company)		

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

As of April 27, 2010, there were 133,399,285 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

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

	March 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$112	$78
Accounts receivable	352	339
Inventories	83	84
Derivative assets	349	269
Other current assets	82	123
Total current assets	978	893
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,480 and $1,223 were excluded from amortization at March 31, 2010 and December 31, 2009, respectively)	10,977	10,406
Less—accumulated depreciation, depletion and amortization	(5,306)	(5,159)
Total property and equipment, net	5,671	5,247
Derivative assets	75	19
Long-term investments	54	55
Deferred taxes	26	26
Other assets	23	14
Total assets	$6,827	$6,254
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$65	$83
Current debt	32	—
Accrued liabilities	649	640
Advances from joint owners	49	51
Asset retirement obligation	10	10
Derivative liabilities	1	2
Deferred taxes	116	87
Total current liabilities	922	873
Other liabilities	60	55
Derivative liabilities	11	5
Long-term debt	2,189	2,037
Asset retirement obligation	88	82
Deferred taxes	537	434
Total long-term liabilities	2,885	2,613
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 March 31, 2010 and December 31, 2009; 135,001,290 and 134,493,670 shares issued at March 31, 2010 and December 31, 2009, respectively)	1	1
Additional paid-in capital	1,406	1,389
Treasury stock (at cost; 1,715,643 and 1,488,968 shares at March 31, 2010 and December 31, 2009, respectively)	(43)	(33)
Accumulated other comprehensive income (loss):		
Unrealized loss on investments	(10)	(11)
Retained earnings	1,666	1,422
Total stockholders' equity	3,020	2,768
Total liabilities and stockholders' equity	$6,827	$6,254

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 March 31, 2010	Three Months Ended March 31, 2009
Oil and gas revenues	$458	$262
Operating expenses:		
Lease operating	67	71
Production and other taxes	25	9
Depreciation, depletion and amortization	147	159
General and administrative	36	32
Ceiling test writedown	—	1,344
Other	8	2
Total operating expenses	283	1,617
Income (loss) from operations	175	(1,355)
Other income (expenses):		
Interest expense	(38)	(32)
Capitalized interest	12	14
Commodity derivative income	237	278
Other	2	3
Total other income (expenses)	213	263
Income (loss) before income taxes	388	(1,092)
Income tax provision (benefit):		
Current	13	5
Deferred	131	(403)
Total income tax provision (benefit)	144	(398)
Net income (loss)	$244	$(694)
Income (loss) per share:		
Basic	$1.87	$(5.35)
Diluted	$1.84	$(5.35)
Weighted average number of shares outstanding for basic income (loss) per share	130	130
Weighted average number of shares outstanding for diluted income (loss) per share	133	130

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

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Cash flows from operating activities:		
Net income (loss)	$244	$(694)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	147	159
Deferred tax provision (benefit)	131	(403)
Stock-based compensation	6	8
Ceiling test writedown		1,344
Commodity derivative income	(237)	(278)
Cash receipts on derivative settlements	102	211
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(13)	73
(Increase) decrease in inventories	5	(17)
(Increase) decrease in other current assets	42	(46)
Decrease in other assets		7
Decrease in accounts payable and accrued liabilities	(16)	(54)
Increase (decrease) in advances from joint owners	(2)	22
Increase in other liabilities	5	17
Net cash provided by operating activities	414	349
Cash flows from investing activities:		
Additions to oil and gas properties	(340)	(403)
Acquisitions of oil and gas properties	(217)	(9)
Proceeds from sales of oil and gas properties	2	
Additions to furniture, fixtures and equipment	(2)	(2)
Redemptions of investments	1	7
Net cash used in investing activities	(556)	(407)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	198	455
Repayments of borrowings under credit arrangements	(562)	(382)
Net proceeds from issuance of senior subordinated notes	686	
Repayment of senior notes	(143)	
Proceeds from issuances of common stock	11	
Purchases of treasury stock, net	(14)	(1)
Net cash provided by financing activities	176	72
Increase in cash and cash equivalents	34	14
Cash and cash equivalents, beginning of period	78	24
Cash and cash equivalents, end of period	$112	$38

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

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

	Common Stock		Treasury Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive Income (Loss)	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Earnings		Equity
Balance, December 31, 2009	134.5	$ 1	(1.5)	$ (33)	$ 1,389	$ 1,422	$ (11)	$ 2,768
Issuances of common and restricted stock	0.5				7			7
Treasury stock, at cost			(0.2)	(10)				(10)
Stock-based compensation					10			10
Comprehensive income:								
Net income						244		244
Unrealized gain on investments							1	1
Total comprehensive income								245
Balance, March 31, 2010	135.0	$ 1	(1.7)	$ (43)	$ 1,406	$ 1,666	$ (10)	$ 3,020

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 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, 2009.

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 fair value of our derivative positions.

Investments

Investments consist primarily of debt and equity securities as well as auction rate securities, substantially all 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 gains on our investment securities of $1 million for the three months ended March 31, 2010 and 2009.

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Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into FPSO's and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 494,000 barrels and 289,000 barrels of crude oil valued at cost of $21 million and $11 million at March 31, 2010 and December 31, 2009, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization 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.

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. For the three months ended March 31, 2010, 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 the newly effective oil and gas reserve estimation requirements (See "New Accounting Requirements" in this Note) which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus

- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less

- related income tax effects.

During the first quarter of 2009, the present value (10% per annum discount rate) of estimated future net revenues from proved reserves was calculated using the end of period quoted market prices for oil and gas.

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

March 31, 2010, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $3.98 per MMBtu for natural gas and $69.61 per barrel for oil, adjusted for market differentials. Using these prices, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective properties. As such, no ceiling test writedowns were required at March 31, 2010.

During the first quarter of 2009, natural gas prices decreased significantly as compared to prices in effect at December 31, 2008. At March 31, 2009, the ceiling value of our reserves was calculated based upon quoted period-end market prices of $3.63 per MMBtu for natural gas and $49.65 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties at March 31, 2009 exceeded the ceiling amount by approximately $1.3 billion ($854 million, after-tax).

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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 three months ended March 31, 2010 is set forth below (in millions):

Balance as of January 1, 2010	$92
Accretion expense	1
Additions	5
Balance at March 31, 2010	$98
Less: Current portion of ARO at March 31, 2010	(10)
Total long-term ARO at March 31, 2010	$88

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.

During the first quarter of 2010, there was no change to our liability of $1 million for uncertain tax positions. As of March 31, 2010, we had not accrued interest or penalties related to uncertain tax positions. The tax years 2006-2009 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject. During the fourth quarter of 2008, the Internal Revenue Service (IRS) commenced a limited scope audit of our U.S. income tax return for the 2005 tax year. The IRS issued a “No Change” letter for the 2005 tax year and closed the audit.

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. Previously, we also utilized derivatives to manage our exposure to variable interest rates. See Note 5, "Derivative Financial Instruments—Interest Rate Swap."

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

New Accounting Requirements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which aligns the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the Securities and Exchange Commission's final rule, Modernization of the Oil and Gas Reporting Requirements (Final Rule), which was issued on December 31, 2008 and became effective for the year ended December 31, 2009. We adopted the Final Rule and ASU 2010-03 effective December 31, 2009, as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change is accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule are not required.

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 is effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures which are effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ending March 31, 2010, except for the Level 3 reconciliation disclosures, which we will adopt for the quarter ending March 31, 2011. Adopting the disclosure requirements for the quarter ending March 31, 2010 did not have an impact on our financial position or results of operations. We do not expect adoption of the Level 3 reconciliation disclosures in 2011 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 incorporates the dilutive impact of outstanding stock options and unvested restricted stock and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. Please see Note 11, "Stock-Based Compensation."

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

	Three Months Ended March 31,	
	2010	2009
	(In millions, except per share data)	
Income (numerator):		

Net income (loss) – basic and diluted	$244	$(694)
Weighted average shares (denominator):		
Weighted average shares — basic	130	130
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period (1)	3	
Weighted average shares — diluted	133	130
Income (loss) per share:		
Basic	$1.87	$(5.35)
Diluted	$1.84	$(5.35)

(1) The effect of stock options and unvested restricted stock and restricted stock units outstanding has not been included in the calculation of shares outstanding for diluted EPS for the three months ended March 31, 2009 as their effect would have been anti-dilutive. Had we recognized net income for this period, incremental shares attributable to the assumed exercise of outstanding options and the assumed vesting of unvested restricted stock and restricted stock units would have increased diluted weighted average shares outstanding by 1 million shares.

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

3. Comprehensive Income (Loss):

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(In millions)	
Net income (loss)	$ 244	$ (694)
Unrealized gain (loss) on investments, net of tax of $1	1	(2)
Total comprehensive income (loss)	$ 245	$ (696)

4. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	March 31, 2010	December 31, 2009
	(In millions)	
Oil and gas properties:		
Subject to amortization	$9,402	$9,090
Not subject to amortization	1,480	1,223
Gross oil and gas properties	10,882	10,313
Accumulated depreciation, depletion and amortization	(5,253)	(5,108)
Net oil and gas properties	5,629	5,205
Other property and equipment	95	93
Accumulated depreciation and amortization	(53)	(51)
Net other property and equipment	42	42
Total property and equipment, net	$5,671	$5,247

The following is a summary of Newfield's oil and gas properties not subject to amortization as of March 31, 2010. We believe that our evaluation activities related to substantially all of our properties not subject to amortization will be completed within four years except the Monument Butte field. Because of its size, evaluation of the field in its entirety will take significantly longer than four years.

Costs Incurred In				
2010	2009	2008	2007 and prior	Total
		(In millions)		

Acquisition costs	$ 169	$ 154	$ 176	$ 389	$ 888
Exploration costs	101	109	54	17	281
Development costs	47	40	34	27	148
Fee mineral interests	2			23	25
Capitalized interest	12	51	60	15	138
Total oil and gas properties not subject to amortization	$ 331	$ 354	$ 324	$ 471	$ 1,480

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Maverick Basin Asset Acquisition

On February 11, 2010, we acquired certain of TXCO Resources Inc.'s assets in the Maverick Basin of southwest Texas for approximately $215 million. In the acquisition, Newfield obtained an interest in approximately 300,000 net acres, primarily in the Pearsall and Eagle Ford shale plays, as well as production of 1,500 barrels of oil equivalent per day. Our consolidated financial statements include the cash flows and results of operations for these assets subsequent to February 11, 2010.

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. None of our derivative contracts contain collateral posting requirements; however, two of our derivative contracts contain a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contract.

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 unrealized and realized 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 March 31, 2010, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu							
			Collars						Estimated Fair Value Asset
		Swaps	Additional Put		Floors		Ceilings		
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	(Liability) (In millions)
April 2010 – June 2010									
Price swap contracts	34,850	$ 6.41	—	—	—	—	—	—	$ 87
July 2010 – September 2010									
Price swap contracts	35,200	6.41	—	—	—	—	—	—	79
October 2010 – December 2010									
Price swap contracts	28,320	6.49	—	—	—	—	—	—	50
January 2011 – December 2011									
Price swap contracts	63,840	6.55	—	—	—	—	—	—	81
3-Way collar contracts	42,590	—	$ 4.50	$ 4.50	$ 6.00	$ 6.00	$ 7.10 - $ 8.03	$ 7.84	27
January 2012 – December 2012									
3-Way collar contracts	25,620	—	4.50	4.50	5.75-6.00	5.85	6.20-7.55	6.87	—
January 2013 – October 2013									
	21,280	—	4.50	4.50	5.75-6.00	5.82		6.88	—

3-Way collar contracts		6.60-7.55	
			$ 324

Oil

		NYMEX Contract Price Per Bbl							
					Collars				Estimated Fair Value
		Swaps	Additional Put		Floors		Ceilings		
Period and Type of Contract	Volume in MBbls	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Asset (Liability) (In millions)
April 2010 – June 2010									
Price swap contracts	272	$ 86.44	—	—	—	—	—	—	$ 1
Collar contracts	819	—	—	—	$125.50–$130.50	$ 127.97	$ 170.00	$ 170.00	36
3-Way collar contracts	364	—	$ 50.00-$60.00	$ 55.00	60.00-75.00	67.50	100.00-112.10	106.28	¾
July 2010 – September 2010									
Price swap contracts	274	86.42	—	—	—	—	—	—	¾
Collar contracts	828	—	—	—	125.50–130.50	127.97	170.00	170.00	36
3-Way collar contracts	368	—	50.00-60.00	55.00	60.00-75.00	67.50	100.00-112.10	106.28	¾
October 2010 – December 2010									
Price swap contracts	274	86.42	—	—	—	—	—	—	¾
Collar contracts	828	—	—	—	125.50–130.50	127.97	170.00	170.00	35
3-Way collar contracts	368	—	50.00-60.00	55.00	60.00-75.00	67.50	100.00-112.10	106.28	¾

January 2011 – December 2011									
3-Way collar contracts	4,564	—	60.00-65.00	60.80	75.00-80.00	75.80	102.25-121.50	108.30	1
January 2012 – December 2012									
3-Way collar contracts	3,294	—	60.00	60.00	75.00	75.00	111.00-111.50	111.31	(3)
									$106

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

Basis Contracts

At March 31, 2010, 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)
April 2010 – June 2010	1,380	$ (0.99)	1,820	$ (0.55)	$ (2)
July 2010 – September 2010	1,380	$ (0.99)	1,840	$ (0.55)	(2)
October 2010 – December 2010	1,380	$ (0.99)	1,840	$ (0.55)	(1)
January 2011 – December 2011	5,280	$ (0.95)	10,350	$ (0.55)	(5)
January 2012 – December 2012	4,920	$ (0.91)	18,300	$ (0.55)	(8)
					$ (18)

Interest Rate Swap

We previously entered into an interest rate swap agreement to take advantage of low interest rates and to obtain what we viewed as a more desirable proportion of variable and fixed rate debt. The agreement was designated as a fair value hedge of $50 million principal amount of our $175 million 7 % Senior Notes due 2011. The interest rate swap provided for us to pay variable and receive fixed interest payments. Changes in the fair value of derivatives designated as fair value hedges were recognized as offsets to the changes in the fair value of the exposure being hedged. As a result, at December 31, 2009, the fair value of our interest rate swap was reflected as a derivative asset on our consolidated balance sheet and changes in its fair value were recorded as an adjustment to the carrying value of the associated debt. Receipts and payments related to our interest rate swap were reflected in interest expense. The related cash flow impact was reflected as cash flows from operating activities in our consolidated statement of cash flows. During the first quarter of 2010, we terminated the swap and received approximately $2 million in settlement of the swap. The settlement of the swap is included under the caption “Operating expenses – Other” on our consolidated statement of income and partially offsets the early redemption premium paid for the tender of the associated 7 % Senior Notes due 2011. See Note 9, "Debt – Senior and Senior Subordinated Notes" for a detailed discussion of this transction.

Additional Disclosures about Derivative Instruments and Hedging Activities

At March 31, 2010, we had derivative financial instruments recorded in our balance sheet as set forth below.

Estimated

Type of Contract	Balance Sheet Location	Fair Value (In millions)
Derivatives not designated as hedging instruments:		
Natural gas contracts	Derivative assets – current	$ 245
Oil contracts	Derivative assets – current	110
Basis contracts	Derivative assets – current	(6)
Natural gas contracts	Derivative assets – noncurrent	79
Oil contracts	Derivative assets – noncurrent	3
Basis contracts	Derivative assets – noncurrent	(7)
Oil contracts	Derivative liabilities – current	(1)
Oil contracts	Derivative liabilities – noncurrent	(6)
Basis contracts	Derivative liabilities – noncurrent	(5)
Total derivatives not designated as hedging instruments		412
Net derivative assets		$ 412

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

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

Type of Contract	Location of Gain/(Loss) Recognized in Income	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Commodity derivative income	$ 253	$ 274
Oil contracts	Commodity derivative income	(11)	17
Basis contracts	Commodity derivative income	(5)	(13)
Total		$ 237	$ 278

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty. At March 31, 2010, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Credit Agricole Corporate & Investment Bank London Branch, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, the largest of which was J Aron & Company and accounted for 28% of our future hedged production.

A significant number of the counterparties to our derivative instruments also are lenders under our credit facility. Our credit facility, 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:

	March 31, 2010	December 31, 2009
	(In millions)	
Revenue	$213	$214
Joint interest	121	114
Other	24	17
Reserve for doubtful accounts	(6)	(6)
Total accounts receivable	$352	$339

7. Accrued Liabilities:

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

	March 31, 2010	December 31, 2009
	(In millions)	
Revenue payable	$68	$55
Accrued capital costs	295	289
Accrued lease operating expenses	44	47
Employee incentive expense	30	61
Accrued interest on debt	44	25
Taxes payable	114	101
Other	54	62
Total accrued liabilities	$649	$640

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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, certain investments and interest rate swaps.

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 price collars and floors 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, 2009:				
Money market fund investments	$15	$—	$ —	$15
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	40	40
Oil and gas derivative swap contracts	—	119	(14)	105
Oil and gas derivative option contracts	—	—	173	173
Interest rate swap	—	3	—	3
Total	$22	$122	$ 199	$343
As of March 31, 2010:				
Money market fund investments	$67	$	$	$67
Investments available-for-sale:				
Equity securities	8			8
Auction rate securities			40	40
Oil and gas derivative swap contracts		298	(18)	280
Oil and gas derivative option contracts			132	132
Total	$75	$298	$ 154	$527

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). We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

As of March 31, 2010, we continued to hold $40 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 $13 million ($10 million net of tax), recorded under the caption “Accumulated other comprehensive income (loss)” on our consolidated balance sheet. The debt instruments underlying these investments are 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, 2009	$59	$542	$601
Total realized or unrealized gains (losses):			
Included in earnings		27	27
Included in other comprehensive income (loss)	(2)		(2)
Purchases, issuances and settlements	(7)	(77)	(84)
Transfers in and out of Level 3			
Balance at March 31, 2009	$50	$492	$542
Change in unrealized gains (losses) relating to investments and derivatives still held at March 31, 2009	$(2)	$9	$7
Balance at January 1, 2010	$40	$159	$199
Total realized or unrealized gains (losses):			
Included in earnings		(20)	(20)
Included in other comprehensive income (loss)	1		1
Purchases, issuances and settlements	(1)	(25)	(26)
Transfers in and out of Level 3			
Balance at March 31, 2010	$40	$114	$154
Change in unrealized gains (losses) relating to investments and derivatives still held at March 31, 2010	$1	$(14)	$(13)

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

Fair Value of Debt

The estimated fair value of our notes, based on quoted market prices on March 31, 2010, was as follows (in millions):

7 % Senior Notes due 2011	$32
6 % Senior Subordinated Notes due 2014	336
6 % Senior Subordinated Notes due 2016	560
7 % Senior Subordinated Notes due 2018	608
6 % Senior Subordinated Notes due 2020	694

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

9. Debt:

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

	March 31, 2010	December 31, 2009
	(In millions)	
Senior unsecured debt:		
Revolving credit facility:		
LIBOR based loans	$20	$384
7 % Senior Notes due 2011	32	175
Fair value of interest rate swap (1)		3
Total senior unsecured notes	32	178
Total senior unsecured debt	52	562
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	
Total debt	2,221	2,037
Less: Current portion of debt	32	
Total long-term debt	$2,189	$2,037

(1) We previously hedged $50 million principal amount of our $175 million 7 % Senior Notes due 2011 through an interest rate swap. The swap provided for us to pay variable and receive fixed interest payments. During the first quarter of 2010, we terminated the swap and received approximately $2 million in settlement of the swap. See Note 5, "Derivative Financial Instruments – Interest Rate Swap."

Credit Arrangements

We have a revolving credit facility which provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent, and matures June 2012. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we can borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders' commodity price assumptions. In the future, total loan commitments under the facility could be increased to a maximum of $1.65 billion if the existing lenders increase their individual loan commitments or new financial institutions are added to the facility. We do not believe we could access such additional capacity in the current credit market. As of March 31, 2010, the largest commitment was 16% of total commitments.

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

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 or (b) a base Eurodollar rate substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (87.5 basis points per annum at March 31, 2010).

We pay commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at March 31, 2010). We incurred fees under this arrangement of approximately $0.5 million and $0.3 million for the three months ended March 31, 2010 and 2009, respectively, which are recorded in interest expense on our consolidated statement of income.

Our credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to 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) of at least 3.5 to 1.0. In addition, for as long as our debt rating is below investment grade, we must maintain a ratio of the calculated net present value of our oil and gas reserves to total debt of at least 1.75 to 1.00. For purposes of this ratio, total debt includes only 50% of the principal amount of our senior subordinated notes. At March 31, 2010 we were in compliance with all of our debt covenants.

As of March 31, 2010, we had no letters of credit outstanding under our credit facility. Letters of credit are subject to an issuance fee of 12.5 basis points and annual fees based on a grid of our debt rating (87.5 basis points at March 31, 2010).

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $120 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.

Our credit facility and senior and senior subordinated notes contain standard events of default and, if any such events of default were to occur, our lenders could terminate future lending commitments under the credit facility and our lenders could declare the outstanding borrowings due and payable. In addition, our credit facility, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations.

Senior and Senior Subordinated Notes

On January 25, 2010, we sold $700 million of 6 % Senior Subordinated Notes due 2020 and received net proceeds of $686 million (net of discount and offering costs). These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility and $215 million to fund the acquisition of assets from TXCO Resources Inc.

On February 19, 2010, we accepted for purchase and payment approximately $143 million of our $175 million aggregate principal amount of 7 % Senior Notes due 2011, representing approximately 82% of the outstanding principal. The tender included the payment of an early redemption premium of $10 million. This premium was recorded under the caption "Operating expenses – Other" on our consolidated statement of income. We funded the tender offer with a portion of the proceeds from our January 25, 2010 Senior Subordinated Notes issuance.

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

10. Income Taxes:

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(In millions)	
Amount computed using the statutory rate	$ 136	$ (382)
Increase (decrease) in taxes resulting from:		
State and local income taxes, net of federal effect	6	(19)
Net effect of different tax rates in non-U.S. jurisdictions	2	
Valuation allowance		3
Total income tax provision (benefit)	$ 144	$ (398)

As of March 31, 2010, 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 our international NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, valuation allowances have been established for these items. 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.

11. Stock-Based Compensation:

We make stock-based compensation awards to employees through the Newfield Exploration Company 2009 Omnibus Stock Plan (the 2009 Omnibus Stock Plan) and to non-employee directors through the Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units.

Historically, we have used unissued shares of stock when stock options are exercised. Beginning in 2009, we began to utilize treasury shares when stock options are exercised, restricted stock is issued or restricted stock units vest.

Shares available for grant under our 2009 Omnibus Stock Plan are reduced by 1.5 times the number of shares of restricted stock or restricted stock units awarded under the plan, and are reduced by 1 times the number of shares subject to stock options awarded under the plan. At March 31, 2010, we had approximately (1) 1.9 million additional shares available for issuance pursuant to our existing employee and director plans if all future employee awards under our 2009 Omnibus Stock Plan are stock options, or (2) 1.2 million additional shares available for issuance pursuant to our existing employee and director plans if all future employee awards under our 2009 Omnibus Stock Plan are restricted stock or restricted stock units. Thus far, all awards under our 2009 Omnibus Stock Plan have been restricted stock unit awards.

For the three month periods ended March 31, 2010 and 2009, we recorded stock-based compensation expense of $10 million and $12 million, respectively, for all plans. Of these amounts, $3 million and $4 million, respectively, were capitalized in oil and gas properties.

The excess tax benefit realized from stock options exercised is recognized as a credit to additional paid in capital and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with recorded stock compensation expense. We did not realize an excess tax benefit from stock compensation for the three months ended March 31, 2010 or 2009 because we do not anticipate having sufficient taxable income to fully realize the deduction. Any excess tax benefits associated with the exercise of stock options in 2010 will be realized when the deduction can be utilized to reduce current income taxes on future tax returns.

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

As of March 31, 2010, we had approximately $68 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting period. The full amount is expected to be recognized within approximately five years.

Stock Options. We have granted stock options under several plans. Options generally expire ten years from the date of grant and become exercisable at the rate of 20% per year. The exercise price of options cannot be less than the fair market value per share of our common stock on the date of grant.

The following table provides information about stock option activity for the three months ended March 31, 2010:

	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, 2009	2.9	$ 29.82		4.7	$ 56
Granted			$ —		
Exercised	(0.5)	22.64			15
Forfeited					
Outstanding at March 31, 2010	2.4	$ 31.29		4.8	$ 49
Exercisable at March 31, 2010	2.1	$ 28.90		4.4	$ 48

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

On March 31, 2010, the last reported sales price of our common stock on the New York Stock Exchange was $52.05 per share.

The following table summarizes information about stock options outstanding and exercisable at March 31, 2010:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options	Weighted Average Remaining	Weighted Average Exercise Price per Share	Number of Shares Underlying Options	Weighted Average Exercise Price per Share

	(In millions)	Contractual Life (In years)			(In millions)		
$ 12.51 to $ 17.50	0.4	2.4	$	16.60	0.4	$	16.60
17.51 to 22.50	0.2	2.4		18.70	0.2		18.70
22.51 to 27.50	0.4	3.9		24.76	0.4		24.76
27.51 to 35.00	0.7	4.8		31.19	0.7		31.18
35.01 to 41.72	0.1	5.1		37.33	0.1		37.03
41.73 to 48.45	0.6	7.9		48.85	0.3		48.45
	2.4	4.8	$	31.29	2.1	$	28.90

Restricted Stock. At March 31, 2010, our employees held an aggregate of 2.3 million shares of restricted stock and restricted stock units that primarily vest over a service period of three to five years. The vesting of these shares and units is dependant upon the employee's continued service with our company. In addition, at March 31, 2010, our employees held 0.3 million shares of restricted stock subject to performance-based vesting criteria (substantially all of which are considered market-based restricted stock under authoritative accounting guidance).

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

The following table provides information about restricted stock and restricted stock unit activity for the three months ended March 31, 2010:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at December 31, 2009	2,424	782	3,206	$ 31.60
Granted	298	140	438	50.14
Forfeited	(46)	(73)	(119)	28.83
Vested	(347)	(521)	(868)	31.43
Non-vested shares outstanding at March 31, 2010	2,329	328	2,657	$ 34.83

The total fair value of restricted stock and restricted stock units that vested during the three months ended March 31, 2010 was $27 million.

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. No employee may purchase common stock under the plan valued at more than $25,000 in any calendar year. Employees of our foreign subsidiaries are not eligible to participate in the plan.

During the first three months of 2010, options to purchase 40,821 shares of our common stock were issued under the plan. The weighted average fair value of each option was $13.08 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 0.20%, an expected life of six months and weighted average volatility of 43%. At March 31, 2010, 358,651 shares of our common stock remained available for issuance under the plan.

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.

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 as of and for the three months ended March 31, 2010 and 2009. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

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

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Three Months Ended March 31, 2010:					
Oil and gas revenues	$359	$84	$15	$ —	$458
Operating expenses:					
Lease operating	56	10	1	—	67
Production and other taxes	16	7	2	—	25
Depreciation, depletion and amortization	115	25	4	3	147
General and administrative	35	1	—	—	36
Other	8	—	—	—	8
Allocated income taxes	47	16	2	—	
Net income (loss) from oil and gas properties	$82	$25	$6	$ (3)	
Total operating expenses					283
Income from operations					175
Interest expense, net of interest income, capitalized interest and other					(24)
Commodity derivative income					237
Income before income taxes					$388
Total long-lived assets	$5,078	$392	$159	$ —	$5,629
Additions to long-lived assets	$525	$42	$8	$ —	$575

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Three Months Ended March 31, 2009:					
Oil and gas revenues	$213	$44	$5	$ —	$262
Operating expenses:					
Lease operating	59	11	1	—	71
Production and other taxes	7	2	—	—	9
Depreciation, depletion and amortization	134	23	2	—	159
General and administrative	32	—	—	—	32
Ceiling test writedown	1,344	—	—	—	1,344
Other	2	—	—	—	2
Allocated income taxes	(491)	3	—	—	
Net income (loss) from oil and gas properties	$(874)	$5	$2	$ —	
Total operating expenses					1,617

Loss from operations					(1,355)
Interest expense, net of interest income, capitalized interest and other					(15)
Commodity derivative income					278
Loss before income taxes					$(1,092)
Total long-lived assets	$4,077	$388	$112	$ 3	$4,580
Additions to long-lived assets	$339	$24	$6	$ —	$369

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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 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, 2009 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.

Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of March 31, 2010, we had net derivative assets of $412 million, of which 28% 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. 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 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 of our annual report on Form 10-K for the year ended December 31, 2009 for a discussion of a number 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. The effects of the settlement of hedges designated for hedge accounting are included in revenue, but those not so designated have no effect on our reported revenues. None of our outstanding oil and gas hedging contracts as of March 31, 2010 are designated for hedge accounting and the settlement of all hedging contracts during the first quarter of 2010 and 2009 had no effect on reported revenues. 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 $458 million for the first quarter of 2010 were 75% higher than the comparable period of 2009 due to significantly higher average realized oil and gas prices, combined with increased oil and gas production.

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	Three Months Ended March 31, 2010	2009	Percentage Increase (Decrease)
Production (1):			
Domestic:			
Natural gas (Bcf)	46.8	44.8	5 %
Oil and condensate (MBbls)	1,759	1,768	(1)%
Total (Bcfe)	57.4	55.4	4 %
International:			
Natural gas (Bcf)	—	—	—
Oil and condensate (MBbls)	1,402	1,201	17 %
Total (Bcfe)	8.4	7.2	17 %
Total:			
Natural gas (Bcf)	46.8	44.8	5 %
Oil and condensate (MBbls)	3,161	2,969	6 %
Total (Bcfe)	65.8	62.6	5 %
Average Realized Prices (2):			
Domestic:			
Natural gas (per Mcf)	$ 5.04	$ 3.48	45 %
Oil and condensate (per Bbl)	69.28	32.26	115 %
Natural gas equivalent (per Mcfe)	6.26	3.84	63 %
International:			
Natural gas (per Mcf)	$ —	$ —	—
Oil and condensate (per Bbl)	70.50	40.67	73 %
Natural gas equivalent (per Mcfe)	11.75	6.78	73 %
Total:			
Natural gas (per Mcf)	$ 5.04	$ 3.48	45 %
Oil and condensate (per Bbl)	69.82	35.66	96 %
Natural gas equivalent (per Mcfe)	6.96	4.18	66 %

(1) Represents volumes lifted and sold regardless of when produced.

(2) Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been $6.34 and $5.48 per Mcf for the three months ended March 31, 2010 and 2009, respectively. Our total oil and condensate average realized price would have been $80.45 and $74.42 per Bbl for the three months ended March 31, 2010 and 2009, respectively.

Domestic Production. Our first quarter 2010 domestic oil and gas production, stated on a natural gas equivalent basis, increased 4% over the comparable period of 2009 primarily due to increased production from continued development of our Gulf of Mexico deepwater discoveries, combined with increased production in our Mid-Continent division as a result of continued successful development drilling efforts, partially offset by a decline in our onshore Gulf Coast production.

International Production. Our first quarter 2010 international oil production, stated on a natural gas equivalent basis, increased 17% over the comparable period of 2009 primarily due to the timing of liftings from our oil production in Malaysia and China.

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

The following table presents information about our operating expenses for the three months ended March 31, 2010 and 2009.

	Unit-of-Production Three Months Ended March 31, 2010	Unit-of-Production Three Months Ended March 31, 2009	Percentage Increase (Decrease)	Total Amount Three Months Ended March 31, 2010	Total Amount Three Months Ended March 31, 2009	Percentage Increase (Decrease)
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.97	$ 1.05	(8)%	$ 56	$ 59	(5)%
Production and other taxes	0.27	0.12	125 %	16	7	132 %
Depreciation, depletion and amortization	2.01	2.42	(17)%	115	134	(14)%
General and administrative	0.62	0.58	7 %	35	32	10 %
Ceiling test writedown	—	24.25	(100)%	—	1,344	(100)%
Other	0.14	0.03	367 %	8	2	454 %
Total operating expenses	4.01	28.45	(86)%	230	1,578	(85)%
International:						
Lease operating	$ 1.34	$ 1.73	(23)%	$ 11	$ 12	(10)%
Production and other taxes	1.10	0.34	224 %	9	2	280 %
Depreciation, depletion and amortization	3.82	3.46	10 %	32	25	29 %
General and administrative	0.11	0.03	267 %	1	—	271 %
Total operating expenses	6.37	5.56	15 %	53	39	34 %
Total:						
Lease operating	$ 1.02	$ 1.13	(10)%	$ 67	$ 71	(5)%
Production and other taxes	0.38	0.15	153 %	25	9	171 %
Depreciation, depletion and amortization	2.24	2.54	(12)%	147	159	(7)%
General and administrative	0.55	0.52	6 %	36	32	12 %
Ceiling test writedown	—	21.46	(100)%	—	1,344	(100)%

Other	0.12	0.02	500 %	8	2	454 %
Total operating expenses	4.31	25.82	(83)%	283	1,617	(82)%

Domestic Operations. Our domestic operating expenses for the three months ended March 31, 2010, stated on a Mcfe basis, decreased 86% over the same period of 2009 primarily due to the full cost ceiling test writedown recorded at March 31, 2009. The components of the period to period change are as follows:

- Lease operating expense (LOE) per Mcfe decreased 8% due to lower overall operating and service costs and the 4% increase in production volumes period over period.

- Production and other taxes per Mcfe increased 125% due to significantly higher realized commodity prices period over period. We received refunds of $2 million ($0.04 per Mcfe) during the first quarter of 2010 related to production tax exemptions on some of our onshore wells, whereas we received similar refunds of $8 million ($0.14 per Mcfe) during the same period of 2009.

- Our depreciation, depletion and amortization (DD&A) rate per Mcfe decreased 17% primarily as a result of the ceiling test writedown recorded at March 31, 2009.

- General and administrative (G&A) expense per Mcfe increased 7% primarily due to increased employee-related expenses associated with our growing domestic workforce. During the first quarter of 2010, we capitalized $16 million of direct internal costs as compared to $13 million in the first quarter of 2009.

- At March 31, 2009, we recorded a ceiling test writedown of $1.3 billion ($24.25 per Mcfe) due to significantly lower natural gas prices.

- Other expenses for the three months ended March 31, 2010, includes the early redemption premium of $10 million associated with the tender of approximately $143 million of our $175 million aggregate principal amount 7 % Senior Notes due 2011, partially offset by the $2 million cash received resulting from the termination of the associated interest rate swap. Other expenses for the three months ended March 31, 2009 includes long-term rig contract termination fees.

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International Operations. Our international operating expenses for the three months ended March 31, 2010, stated on a Mcfe basis, increased 15% over the same period of 2009. The components of the period to period change are as follows:

- LOE per Mcfe decreased 23% due to lower overall operating and service costs and the 17% increase in production volumes period over period.

- Production and other taxes increased significantly due to substantially higher realized oil prices period over period.

- The DD&A rate per Mcfe increased 10% primarily due to unsuccessful exploratory drilling efforts in offshore China.

- G&A expense per Mcfe increased $0.08 primarily due to increased employee-related expenses and consulting and contracting expenses associated with our growing international operations.

Commodity Derivative Income

The significant fluctuation in commodity derivative income from period to period is due to the extreme 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 March 31,	
	2010	2009
	(In millions)	
Gross interest expense:		
Credit arrangements	$ 1	$ 2
Senior notes	2	3
Senior subordinated notes	35	26
Other		1
Total gross interest expense	38	32
Capitalized interest	(12)	(14)
Net interest expense	$ 26	$ (18)

The 18% increase in gross interest expense for the first quarter of 2010 as compared to the same period of 2009 primarily resulted from the issuance of $700 million of 6 % Senior Subordinated Notes due 2020 in January 2010, partially offset by the tender of $143 million of our $175 million aggregate principal amount of 7 % Senior Notes. See Note 9, “Debt,” to our consolidated financial statements appearing earlier in this report.

Taxes. The effective tax rates for the first quarter of 2010 and 2009 were 37.1% and 36.4%, respectively. Our effective tax rate for all periods was different than the federal statutory tax rate due to deductions that do not generate tax benefits, state income taxes and the differences between international and U.S. federal statutory rates. Estimates of future taxable income can be significantly affected by changes in oil and gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

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Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow our production and cash 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. Our 2010 capital budget is $1.6 billion and focuses on projects we believe will generate and lay the foundation for production growth. Our 2010 capital budget (excluding acquisitions) is guided by our anticipated 2010 cash flows.

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.

On January 25, 2010, we sold $700 million of 6 % Senior Subordinated Notes due 2020 and received net proceeds of $686 million (net of discount and offering costs). These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility and $215 million to fund the acquisition of assets from TXCO Resources Inc.

On February 19, 2010, we accepted for purchase and payment approximately $143 million of our $175 million aggregate principal amount 7 % Senior Notes due 2011, representing approximately 82% of the outstanding principal. The tender included the payment of an early redemption premium of $10 million. This premium was recorded under the caption “Operating expenses – Other” on our consolidated statement of income. We funded the tender offer with a portion of the proceeds from our January 25, 2010 Senior Subordinated Notes issuance.

We continue to hold auction rate securities with a fair value of $40 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. We have a revolving credit facility that matures in June 2012 and provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent. As of March 31, 2010, the largest commitment was 16% of total commitments. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we may borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders’ commodity price assumptions.

In the future, total commitments under the facility could be increased to a maximum of $1.65 billion if the existing lenders increase their individual loan commitments or new financial institutions are added to the facility. We do not believe we could access such additional capacity in the current credit market. 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 $120 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 institution. 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 April 27, 2010, we had no letters of credit or outstanding borrowings under our $1.25 billion credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.4 billion as of April 27, 2010.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. Although we anticipate that our 2010 capital spending (excluding acquisitions) will correspond with our anticipated 2010 cash flows, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At March 31, 2010, we had positive working capital of $56 million compared to $20 million at December 31, 2009. The increase in our working capital as compared to December 31, 2009 is primarily due to an increase in our cash balance of $34 million and the increase in our net derivative assets of $81 million due to lower natural gas futures prices at March 31, 2010 as compared to December 31, 2009, partially offset by the related increase in the associated deferred tax liability of $29 million. The increase was partially offset by the reclassification of the remaining $32 million of our 7 % Senior Notes due February 2011 as a current liability.

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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.

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 $414 million for the three months ended March 31, 2010, an increase of 19% compared to net cash flows from operations of $349 million for the same period in 2009. Our first quarter of 2010 net cash flows from operations were positively impacted by significantly higher average realized commodity prices and lower overall operating and service costs.

Cash Flows from Investing Activities. Net cash used in investing activities for the three months ended March 31, 2010 was $556 million compared to $407 million for the same period in 2009.

During the three months ended March 31, 2010, we:

- spent $557 million (including $217 million for acquisitions of oil and gas properties).

During the three months ended March 31, 2009, we:

- spent $412 million (including $9 million for acquisitions of oil and gas properties); and
- redeemed investments of $7 million.

Capital Expenditures. Our capital spending of $570 million for the first quarter of 2010 increased 55% from our capital spending of $368 million during the same period of 2009. These amounts exclude recorded asset retirement obligations of $5 million and $1 million in the 2010 and 2009 periods, respectively. Of the $570 million spent during the first quarter of 2010, we invested $254 million in domestic exploitation and development, $38 million in domestic exploration (exclusive of exploitation and leasehold activity), $231 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $47 million outside the United States. Of the $368 million spent during the first quarter of 2009, we invested $285 million in domestic exploitation and development, $52 million in domestic exploration (exclusive of exploitation and leasehold activity), $1 million in domestic leasehold activity and $30 million outside the United States.

We have budgeted $1.6 billion for capital spending in 2010 (excluding acquisitions), including $124 million of estimated capitalized interest and overhead. As a result of the continued spread between oil and gas prices, we have re-allocated approximately $200 million of our budget from natural gas projects to oil projects in our portfolio. We currently expect to invest approximately $700 million in oil projects in 2010, or nearly 45% of our total budget. The 2010 capital budget is based on our expectation that we will live within anticipated cash flow from operations (excluding acquisitions). 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.

Cash Flows from Financing Activities. Net cash flows provided by financing activities for the first three months of 2010 were $176 million compared to $72 million for the same period in 2009.

During the three months ended March 31, 2010, we:

- borrowed $198 million and repaid $562 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 $143 million of our $175 million aggregate principal amount 7 % Senior Notes due 2011;
- 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; and
- received proceeds of $11 million from the issuance of shares of our common stock upon the exercise of stock options.

During the three months ended March 31, 2009, we borrowed $455 million and repaid $382 million under our credit arrangements.

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Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of March 31, 2010.

	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$20	$—	$20	$—	$—
7 % Senior Notes due 2011	32	32	—	—	—
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	700	—	—	—	700
Total debt	2,227	32	20	325	1,850
Other obligations:					
Interest payments(1)	1,180	152	298	286	444
Net derivative (assets) liabilities	(412)	(349)	(63)	—	—
Asset retirement obligations	98	10	13	13	62
Operating leases	124	48	23	22	31
Deferred acquisition payments	2	2	—	—	—
Firm transportation	602	47	131	140	284
Oil and gas activities(2)	123	—	—	—	—
Total other (assets) obligations	1,717	(90)	402	461	821
Total contractual (assets) obligations	$3,944	$(58)	$422	$786	$2,671

(1) Interest associated with our revolving credit facility was calculated using a weighted average interest rate of approximately 1.1% at March 31, 2010 and is included through the maturity of the facility.

(2) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, natural gas transportation, and fulfilling other cash commitments. At March 31, 2010, these work-related commitments totaled $123 million, all of which were attributable to our international business.

As of March 31, 2010, we have delivery commitments through 2011 to deliver to third party purchasers approximately 100,000 MMBtu of our daily production, principally from our Mid-Continent division. These commitments continue through 2012 at approximately 60,000 MMBtu of our daily production. Given the size of our proved natural gas reserves and production capacity in our Mid-Continent division, we currently believe that we have sufficient reserves and production to fulfill these delivery commitments.

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 March 31, 2010, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Credit Agricole Corporate & Investment Bank London Branch, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, the largest of which was J Aron & Company and accounted for 28% of our future hedged production.

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A significant number of the counterparties to our hedging arrangements also are lenders under our credit facility. Our credit facility, 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. None of our derivative contracts contain collateral posting requirements; however, two of our derivative contracts contain a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contract.

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 85-90% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 14 Bcf of our natural gas production from April 2010 through December 2012 to lock in the differential at a weighted average of $0.95 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 $0.93 per MMBtu. In the Mid-Continent, we hedged basis associated with approximately 10 Bcf of our anticipated Stiles/Britt Ranch natural gas production from April 2010 through August 2011. In total, this hedge and the 30,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.52 per MMBtu. We have also hedged basis associated with approximately 23 Bcf of our natural gas production from this area for the period September 2011 through December 2012 at an average of $0.55 per MMBtu.

The price we receive for our Gulf Coast oil production typically averages about 90-95% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about $12-$14 per barrel below the WTI price. Oil production from our Mid-Continent properties typically averages 88-92% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 90-95% of WTI. Oil sales from our operations in China typically sell at $4-$6 per barrel less than the WTI price.

Between April 1, 2010 and April 28, 2010, we entered into additional natural gas derivative contracts as set forth below.

Period and Type of Contract	Volume in MMMBtus	Weighted Average NYMEX Contract Price per MMBtu
January 2011-December 2011		
Price swap contracts	21,900	$ 5.42
January 2012-October 2012		
Price swap contracts	18,300	5.42

New Accounting Standards

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which aligns the FASB’s oil and gas reserve estimation and disclosure requirements with the requirements in the Securities and Exchange Commission’s final rule, Modernization of the Oil and Gas Reporting Requirements (Final Rule), which was issued on December 31, 2008 and became effective for the year ended December 31, 2009. We adopted the Final Rule and ASU 2010-03 effective December 31, 2009, as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change is accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule are not required.

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 is effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures which are effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ending March 31, 2010, except for the Level 3 reconciliation disclosures, which we will adopt for the quarter ending March 31, 2011. Adopting the disclosure requirements for the quarter ending March 31, 2010 did not have an impact on our financial position or results of operations. We do not expect adoption of the Level 3 reconciliation disclosures in 2011 to have an impact on our financial position or results of operations.

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 governmental regulations;
- the availability and 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 refining capacity for the crude oil we produce from our Monument Butte field;
- 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;
- 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” in Item 1A of our annual report on Form 10-K for the year ended December 31, 2009.

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, 2009. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for additional information about factors that may affect our businesses and operating results. 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. We do not intend to update these statements unless securities laws require us to do so.

Commonly Used Oil and Gas Terms

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

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.

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

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.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drill are located in the Mid-Continent or the Monument Butte field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. An exploration well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

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 March 31, 2010, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$ 20
7 % Senior Notes due 2011	32	
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	$ 2,201	$ 20

We consider our interest rate exposure to be minimal because approximately 99% of our debt obligations were at fixed rates.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country’s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flow, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at March 31, 2010.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2010.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the first quarter of 2010 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 Newfield's legal proceedings previously reported in Newfield's annual report on Form 10-K for the year ended December 31, 2009.

Item 1A. Risk Factors

There have been no material changes with respect to Newfield's risk factors previously reported in Newfield's annual report on Form 10-K for the year ended December 31, 2009.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended March 31, 2010.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate) Dollar Value) of Shares that May Yet be Purchased Under the Plans or

				Programs
January 1 – January 31, 2010	1,803	$50.09	—	—
February 1 – February 28, 2010	206,450	50.61	—	—
March 1 – March 31, 2010	68,671	52.01	—	—
Total	276,924	$50.96	—	—

(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
4.1.1	First Supplemental Indenture, dated as of February 19, 2010, to Senior Indenture dated as of February 28, 2001 between Newfield and U.S. Bank National Association (as successor to First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield's Current Report on Form 8-K filed with the SEC on February 19, 2010 (File No. 1-12534))
4.2.4	Fifth Supplemental Indenture, dated as of January 25, 2010, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Newfield's Current Report on Form 8-K filed with the SEC on January 25, 2010 (File No. 1-12534))
10.20	Form of 2010 TSR Restricted Stock Unit Agreement between Newfield and its executive officers dated as of February 4, 2010 (incorporated by reference to Exhibit 10.20 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 1-12534))
10.21	Form of 2010 Restricted Stock Unit Agreement between Newfield and its executive officers dated as of February 4, 2010 (incorporated by reference to Exhibit 10.21 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 1-12534))
10.23	Summary of Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.23 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 1-12534))
31.1*	Certification of Chief Executive Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished herewith.

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SIGNATURE

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

NEWFIELD EXPLORATION COMPANY

Date: April 30, 2010	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer

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