NEWFIELD EXPLORATION CO /DE/
Form 10-Q
October 24, 2008

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

(Mark One)

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

For the Quarterly Period Ended September 30, 2008

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 2020
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 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<br>(Do not check if a smaller reporting company) | Smaller reporting company o |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes o No þ

As of October 21, 2008, there were 132,245,108 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $ 35 | $ 250 |
| Short-term investments | — | 120 |
| Accounts receivable | 401 | 332 |
| Inventories | 87 | 82 |
| Derivative assets | 213 | 72 |
| Deferred taxes | — | 35 |
| Other current assets | 64 | 36 |
| Total current assets | 800 | 927 |
| Oil and gas properties (full cost method, of which $1,640 at September 30, 2008 and $1,189 at December 31, 2007 were excluded from amortization) | 11,540 | 9,791 |
| Less—accumulated depreciation, depletion and amortization | (4,360) | (3,868) |
| | 7,180 | 5,923 |
| Furniture, fixtures and equipment, net | 41 | 35 |
| Derivative assets | 252 | 17 |
| Long-term investments | 78 | 10 |
| Other assets | 19 | 12 |
| Goodwill | 62 | 62 |
| Total assets | $ 8,432 | $ 6,986 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable | $ 74 | $ 52 |
| Accrued liabilities | 764 | 671 |
| Advances from joint owners | 46 | 44 |
| Asset retirement obligation | 7 | 6 |
| Deferred taxes | 45 | — |
| Derivative liabilities | 67 | 156 |
| Total current liabilities | 1,003 | 929 |
| Other liabilities | 34 | 18 |
| Derivative liabilities | 111 | 248 |
| Long-term debt | 1,936 | 1,050 |
| Asset retirement obligation | 61 | 56 |
| Deferred taxes | 1,253 | 1,104 |
| Total long-term liabilities | 3,395 | 2,476 |

| | | | | |
|---|---|---|---|---|
| Commitments and contingencies (Note 5) | | — | | — |
| Stockholders' equity: | | | | |
| Preferred stock ($0.01 par value; 5,000,000 shares authorized; no shares issued) | | — | | — |
| Common stock ($0.01 par value; 200,000,000 shares authorized at September 30, 2008 and December 31, 2007; 134,124,338 and 133,232,197 shares issued at September 30, 2008 and December 31, 2007, respectively) | | 1 | | 1 |
| Additional paid-in capital | | 1,322 | | 1,278 |
| Treasury stock (at cost; 1,901,413 and 1,896,286 shares at September 30, 2008 and December 31, 2007, respectively) | | (32) | | (32) |
| Accumulated other comprehensive income (loss): | | | | |
| Minimum pension liability | | (3) | | (3) |
| Unrealized loss on investments | | (7) | | — |
| Retained earnings | | 2,753 | | 2,337 |
| Total stockholders' equity | | 4,034 | | 3,581 |
| Total liabilities and stockholders' equity | $ | 8,432 | $ | 6,986 |

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| Oil and gas revenues | $ 680 | $ 419 | $ 1,887 | $ 1,384 |
| Operating expenses: | | | | |
| Lease operating | 67 | 64 | 184 | 268 |
| Production and other taxes | 51 | 25 | 154 | 63 |
| Depreciation, depletion and amortization | 181 | 162 | 504 | 539 |
| General and administrative | 36 | 37 | 105 | 107 |
| Total operating expenses | 335 | 288 | 947 | 977 |
| Income from operations | 345 | 131 | 940 | 407 |
| Other income (expenses): | | | | |
| Interest expense | (36) | (29) | (83) | (80) |
| Capitalized interest | 16 | 13 | 43 | 35 |
| Commodity derivative income (expense) | 726 | 38 | (247) | (43) |
| Other | 8 | 1 | 10 | 3 |
| | 714 | 23 | (277) | (85) |
| Income from continuing operations before income taxes | 1,059 | 154 | 663 | 322 |
| Income tax provision: | | | | |
| Current | 9 | 57 | 34 | 78 |
| Deferred | 326 | 5 | 213 | 47 |
| | 335 | 62 | 247 | 125 |
| Income from continuing operations | 724 | 92 | 416 | 197 |
| Loss from discontinued operations, net of tax | — | (9) | — | (60) |
| Net income | $ 724 | $ 83 | $ 416 | $ 137 |
| Earnings (loss) per share: | | | | |
| Basic — | | | | |
| Income from continuing operations | $ 5.59 | $ 0.72 | $ 3.22 | $ 1.54 |
| Loss from discontinued operations | — | (0.07) | — | (0.47) |
| Net income | $ 5.59 | $ 0.65 | $ 3.22 | $ 1.07 |
| Diluted — | | | | |
| Income from continuing operations | $ 5.48 | $ 0.70 | $ 3.15 | $ 1.51 |
| Loss from discontinued operations | — | (0.06) | — | (0.46) |

| | | | | |
|---|---|---|---|---|
| Net income | $ 5.48 | $ 0.64 | $ 3.15 | $ 1.05 |
| Weighted average number of shares outstanding for basic earnings (loss) per share | 129 | 128 | 129 | 127 |
| Weighted average number of shares outstanding for diluted earnings (loss) per share | 132 | 131 | 132 | 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)

| | Nine Months Ended September 30, 2008 | 2007 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income | $ 416 | $ 137 |
| | | |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Loss from discontinued operations, net of tax | — | 60 |
| Depreciation, depletion and amortization | 504 | 539 |
| Stock-based compensation | 17 | 18 |
| Commodity derivative expense | 247 | 43 |
| Cash (payments) receipts on derivative settlements | (783) | 174 |
| Deferred taxes | 213 | 47 |
| | | |
| Changes in operating assets and liabilities: | | |
| Increase in accounts receivable | (63) | (12) |
| Increase in inventories | (5) | (29) |
| Decrease (increase) in other current assets | (10) | 18 |
| Decrease in other assets | — | 7 |
| Increase in commodity derivative assets | (65) | (2) |
| Increase (decrease) in accounts payable and accrued liabilities | 135 | (8) |
| Increase (decrease) in advances from joint owners | 2 | (53) |
| Increase in other liabilities | 14 | 4 |
| Net cash provided by continuing activities | 622 | 943 |
| Net cash used in discontinued activities | — | (12) |
| Net cash provided by operating activities | 622 | 931 |
| | | |
| Cash flows from investing activities: | | |
| Acquisition of oil and gas properties | (231) | (578) |
| Additions to oil and gas properties | (1,537) | (1,532) |
| Proceeds from sale of oil and gas properties | 2 | 1,281 |
| Additions to furniture, fixtures and equipment | (14) | (7) |
| Purchases of short-term investments | (22) | (43) |
| Redemption of short-term investments | 70 | 24 |
| Net cash used in continuing activities | (1,732) | (855) |
| Net cash used in discontinued activities | — | (41) |
| Net cash used in investing activities | (1,732) | (896) |
| | | |
| Cash flows from financing activities: | | |
| Proceeds from borrowings under credit arrangements | 1,826 | 2,909 |
| Repayments of borrowings under credit arrangements | (1,541) | (2,909) |
| Net proceeds from issuance of senior subordinated notes | 592 | — |
| Payments to discontinued operations | — | (38) |
| Proceeds from issuances of common stock | 18 | 18 |
| Stock-based compensation excess tax benefit | — | 8 |

| | | | | |
|---|---|---|---|---|
| Purchases of treasury stock | | — | | (1) |
| Net cash provided by (used in) continuing activities | | 895 | | (13) |
| Net cash provided by discontinued activities | | — | | 38 |
| Net cash provided by financing activities | | 895 | | 25 |
| | | | | |
| Effect of exchange rate changes on cash and cash equivalents | | — | | 1 |
| | | | | |
| Increase (decrease) in cash and cash equivalents | | (215) | | 61 |
| Cash and cash equivalents, beginning of period | | 250 | | 52 |
| Cash and cash equivalents from discontinued operations, beginning of period | | — | | 28 |
| Cash and cash equivalents, end of period | $ | 35 | $ | 141 |

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

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

| | Common Stock | | Treasury Stock | | Additional Paid-in | Retained | Accumulated Other Comprehensive Income | Total Stockholders' |
|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Capital | Earnings | (Loss) | Equity |
| Balance, December 31, 2007 | 133.2 | $ 1 | (1.9) | $ (32) | $ 1,278 | $ 2,337 | $ (3) | $ 3,581 |
| Issuance of common and restricted stock | 0.8 | | | | 18 | | | 18 |
| Stock-based compensation | 0.1 | | | | 26 | | | 26 |
| Comprehensive income (loss): | | | | | | | | |
| Net income | | | | | | 416 | | 416 |
| Unrealized loss on investments, net of tax of $3 | | | | | | | (7) | (7) |
| Total comprehensive income | | | | | | | | 409 |
| Balance, September 30, 2008 | 134.1 | $ 1 | (1.9) | $ (32) | $ 1,322 | $ 2,753 | $ (10) | $ 4,034 |

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 natural gas and crude oil 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, 2007.

In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash and recorded a gain of $341 million. As a result, the historical results of operations and financial position of our U.K. North Sea operations are reflected in our financial statements as “discontinued operations.” This reclassification affects the presentation of our prior period financial statements. See Note 13, “Discontinued Operations.” Except where noted, discussions in these notes relate to our continuing operations only.

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 natural gas and oil. 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.

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. Our long-term investments at September 30, 2008 included $68 million of auction rate securities. This amount reflects a decrease in the fair value of these investments of $7 million recorded under “Accumulated other comprehensive income (loss)” on our consolidated balance sheet. We realized interest income on our investments of $1 million and $3 million, respectively, for the three and nine months ended September 30, 2008.

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

Foreign Currency

The functional currency for all of our foreign operations is the U.S. dollar. Gains and losses incurred on currency transactions in other than a country's functional currency are recorded under the caption "Other income (expense) — Other" on our consolidated statement of income.

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 floating production, storage and off-loading vessels and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 337,000 barrels and 480,000 barrels of crude oil valued at cost of $14 million and $17 million at September 30, 2008 and December 31, 2007, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

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 as depreciation, depletion and amortization expense on our consolidated statement of income.

The changes to our ARO for the nine months ended September 30, 2008 are set forth below (in millions):

| | | |
|---|---|---|
| Balance as of January 1, 2008 | $ | 62 |
| Accretion expense | | 3 |
| Additions | | 4 |
| Settlements | | (1) |
| Balance at September 30, 2008 | | 68 |
| Current portion of ARO | | (7) |
| Total long-term ARO at September 30, 2008 | $ | 61 |

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

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 on 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.

We adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 48,"Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109," (FIN 48) on January 1, 2007. The adoption did not result in a material adjustment to our tax liability for unrecognized income tax benefits. If applicable, we would recognize interest and penalties related to uncertain tax positions in interest expense. As of September 30, 2008, we had not accrued interest or penalties related to uncertain tax positions. The tax years 2005-2008 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

New Accounting Standards

In March 2008, the FASB issued FASB Statement (SFAS) No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (SFAS No. 161). This statement requires enhanced disclosures about our derivative and hedging activities. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We will adopt SFAS No. 161 beginning January 1, 2009. We are currently evaluating the impact, if any, the statement will have on our consolidated financial statements.

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 shares 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. See Note 11, "Stock-Based Compensation."

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In millions, except per share data) | | | |
| Income (numerator): | | | | |
| Income from continuing operations | $ 724 | $ 92 | $ 416 | $ 197 |
| Loss from discontinued operations, net of tax | — | (9) | — | (60) |
| Net income – basic and diluted | $ 724 | $ 83 | $ 416 | $ 137 |
| | | | | |
| Weighted average shares (denominator): | | | | |
| Weighted average shares – basic | 129 | 128 | 129 | 127 |
| Dilution effect of stock options and unvested restricted stock outstanding at end of period (1) | 3 | 3 | 3 | 3 |
| Weighted average shares – diluted | 132 | 131 | 132 | 130 |
| | | | | |
| Earnings per share: | | | | |
| Basic – | | | | |
| Income from continuing operations | $ 5.59 | $ 0.72 | $ 3.22 | $ 1.54 |
| Loss from discontinued operations | — | (0.07) | — | (0.47) |
| Basic earnings per share | $ 5.59 | $ 0.65 | $ 3.22 | $ 1.07 |
| | | | | |
| Diluted – | | | | |
| Income from continuing operations | $ 5.48 | $ 0.70 | $ 3.15 | $ 1.51 |
| Loss from discontinued operations | — | (0.06) | — | (0.46) |
| Diluted earnings per share | $ 5.48 | $ 0.64 | $ 3.15 | $ 1.05 |

(1) The calculation of shares outstanding for diluted EPS for the three month periods ended September 30, 2008 and 2007 does not include the effect of 0.8 million and 0.2 million, respectively, of outstanding stock options and unvested restricted shares or restricted share units because to do so would be antidilutive. The calculation of shares outstanding for diluted EPS for the nine month periods ended September 30, 2008 and 2007 does not include the effect of 0.3 million and 0.6 million, respectively, of outstanding stock options and unvested restricted shares or restricted share units because to do so would be antidilutive.

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

3. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (In millions) | |
| Subject to amortization | $ 9,900 | $ 8,602 |
| Not subject to amortization: | | |
| Exploration in progress | 434 | 250 |
| Development in progress | 79 | 30 |
| Capitalized interest | 128 | 103 |
| Fee mineral interests | 23 | 23 |
| Other capital costs: | | |
| Incurred in 2008 | 265 | — |
| Incurred in 2007 | 337 | 342 |
| Incurred in 2006 | 67 | 77 |
| Incurred in 2005 and prior | 307 | 364 |
| Total not subject to amortization | 1,640 | 1,189 |
| Gross oil and gas properties | 11,540 | 9,791 |
| Accumulated depreciation, depletion and amortization | (4,360) | (3,868) |
| Net oil and gas properties | $ 7,180 | $ 5,923 |

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

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using end of period oil and gas prices 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.

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. We did not have a ceiling test writedown at September 30, 2008.

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

Pro Forma Results – Rocky Mountain Asset Acquisition

In June 2007, we acquired Stone Energy Corporation's Rocky Mountain assets for $578 million in cash. The unaudited pro forma results presented below for the nine month period ended September 30, 2007 have been prepared to give effect to the acquisition on our results of operations as if it had been consummated at the beginning of the period. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

| | | Nine Months Ended September 30, 2007 (Unaudited) (In millions, except per share data) |
|---|---|---|
| Pro forma: | | |
| Revenue | $ | 1,432 |
| Income from operations | | 468 |
| Net income | | 198 |
| Basic earnings per share | $ | 1.55 |
| Diluted earnings per share | $ | 1.52 |

4. Debt:

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

| | | September 30, 2008 | | December 31, 2007 |
|---|---|---|---|---|
| | | (In millions) | | |
| Senior unsecured debt: | | | | |
| Revolving credit facility: | | | | |
| Prime rate based loans | $ | — | $ | — |
| LIBOR based loans | | 285 | | — |
| Total revolving credit facility | | 285 | | — |
| Money market line of credit (1) | | — | | — |
| Total credit arrangements | | 285 | | — |
| | | | | |
| 7 5/8% Senior Notes due 2011 | | 175 | | 175 |
| Fair value of interest rate swaps (2) | | 1 | | — |
| Total senior unsecured notes | | 176 | | 175 |
| | | | | |
| Total senior unsecured debt | | 461 | | 175 |
| 6 5/8% Senior Subordinated Notes due 2014 | | 325 | | 325 |
| 6 5/8% Senior Subordinated Notes due 2016 | | 550 | | 550 |
| 7 1/8% Senior Subordinated Notes due 2018 | | 600 | | — |
| Total debt | $ | 1,936 | $ | 1,050 |

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

(2) We have hedged $50 million principal amount of our $175 million 7 5/8% Senior Notes due 2011. The hedge provides for us to pay variable and receive fixed interest payments.

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

Senior Subordinated Notes

On May 5, 2008, we sold $600 million principal amount of our 7 1/8% Senior Subordinated Notes due 2018. We received net proceeds from the offering of approximately $592 million. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness, equally in right of payment to our outstanding 6 5/8% Senior Subordinated Notes due 2014 and our 6 5/8% Senior Subordinated Notes due 2016, and senior to all of our future indebtedness that is expressly subordinated to the notes. We may redeem some or all of the notes at any time on or after May 15, 2013 at a redemption price stated in the indenture governing the notes. Prior to May 15, 2013, we may redeem all, but not part, of the notes at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before May 15, 2011, we may redeem up to 35% of the original principal amount of the notes with the net cash proceeds of certain sales of our common stock at 107.125% of the principal amount, plus accrued and unpaid interest to the date of redemption. Like our other senior subordinated notes, these notes may limit our ability under certain circumstances to incur additional debt, make restricted payments, pay dividends on or redeem our capital stock, make certain investments, create liens, engage in transactions with affiliates and engage in mergers, consolidations and sales and other dispositions of assets.

Credit Arrangements

In June 2007, we entered into a new revolving credit facility to replace our previous facility. The credit facility matures in June 2012 and provides for initial loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent. As of September 30, 2008, the largest commitment by a single member of the syndicate was 8% of total commitments. Total loan commitments may 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. 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 September 30, 2008).

Under our current credit facility and our previous credit facilities, we pay or paid commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at September 30, 2008). We incurred fees under these arrangements of approximately $0.4 million and $1 million for the three and nine months ended September 30, 2008, 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 and unrealized gains and losses on commodity derivatives) 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 properties 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.

As of September 30, 2008, we had $26 million of undrawn 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 September 30, 2008).

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

5. Commitments and Contingencies:

We have been named as a defendant in a number of lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits 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.

6. 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 required by SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as well as results of operations of oil and gas producing activities required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," as of and for the three and nine months ended September 30, 2008 and 2007 for our continuing operations. 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)

| | United States | Malaysia | China (In millions) | Other International | Total |
|---|---|---|---|---|---|
| Three Months Ended September 30, 2008: | | | | | |
| Oil and gas revenues | $ 560 | $ 103 | $ 17 | $ — | $ 680 |
| Operating expenses: | | | | | |
| Lease operating | 54 | 13 | — | — | 67 |
| Production and other taxes | 21 | 27 | 3 | — | 51 |
| Depreciation, depletion and amortization | 154 | 24 | 3 | — | 181 |
| General and administrative | 35 | 1 | — | — | 36 |
| Allocated income taxes | 113 | 15 | 2 | — | |
| Net income from oil and gas properties | $ 183 | $ 23 | $ 9 | $ — | |
| Total operating expenses | | | | | 335 |
| Income from operations | | | | | 345 |
| Interest expense, net of interest income, capitalized interest and other | | | | | (12) |
| Commodity derivative income | | | | | 726 |
| Income before income taxes | | | | | $ 1,059 |
| Total long-lived assets | $ 6,629 | $ 442 | $ 107 | $ 2 | $ 7,180 |
| Additions to long-lived assets | $ 462 | $ 45 | $ 7 | $ — | $ 514 |

| | United States | Malaysia | China (In millions) | Other International | Total |
|---|---|---|---|---|---|
| Three Months Ended September 30, 2007: | | | | | |
| Oil and gas revenues | $ 384 | $ 31 | $ 4 | $ — | $ 419 |
| Operating expenses: | | | | | |
| Lease operating | 54 | 9 | 1 | — | 64 |
| Production and other taxes | 20 | 5 | — | — | 25 |
| Depreciation, depletion and amortization | 153 | 8 | 1 | — | 162 |
| General and administrative | 35 | 1 | 1 | — | 37 |
| Allocated income taxes | 44 | 3 | — | — | |
| Net income from oil and gas properties | $ 78 | $ 5 | $ 1 | $ — | |
| Total operating expenses | | | | | 288 |
| Income from operations | | | | | 131 |

| | | | | | |
|---|---|---|---|---|---|
| Interest expense, net of interest income, capitalized interest and other | | | | | (15) |
| Commodity derivative income | | | | | 38 |
| Income from continuing operations before income taxes | | | | | $ 154 |
| Total long-lived assets | $ 5,159 | $ 313 | $ 74 | $ 1 | $ 5,547 |
| Additions to long-lived assets | $ 398 | $ 74 | $ 5 | $ — | $ 477 |

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

| | United States | Malaysia | China (In millions) | Other International | Total |
|---|---|---|---|---|---|
| Nine Months Ended September 30, 2008: | | | | | |
| Oil and gas revenues | $ 1,589 | $ 246 | $ 52 | $ — | $ 1,887 |
| Operating expenses: | | | | | |
| Lease operating | 147 | 35 | 2 | — | 184 |
| Production and other taxes | 64 | 79 | 11 | — | 154 |
| Depreciation, depletion and amortization | 438 | 57 | 9 | — | 504 |
| General and administrative | 101 | 2 | 2 | — | 105 |
| Allocated income taxes | 319 | 28 | 7 | — | |
| Net income from oil and gas properties | $ 520 | $ 45 | $ 21 | $ — | |
| Total operating expenses | | | | | 947 |
| Income from operations | | | | | 940 |
| Interest expense, net of interest income, capitalized interest and other | | | | | (30) |
| Commodity derivative expense | | | | | (247) |
| Income before income taxes | | | | | $ 663 |
| Total long-lived assets | $ 6,629 | $ 442 | $ 107 | $ 2 | $ 7,180 |
| Additions to long-lived assets | $ 1,587 | $ 132 | $ 38 | $ 1 | $ 1,758 |

| | United States | Malaysia | China (In millions) | Other International | Total |
|---|---|---|---|---|---|
| Nine Months Ended September 30, 2007: | | | | | |
| Oil and gas revenues | $ 1,296 | $ 60 | $ 28 | $ — | $ 1,384 |
| Operating expenses: | | | | | |
| Lease operating | 245 | 21 | 2 | — | 268 |
| Production and other taxes | 51 | 10 | 2 | — | 63 |
| Depreciation, depletion and amortization | 517 | 15 | 7 | — | 539 |
| General and administrative | 104 | 1 | 2 | — | 107 |
| Allocated income taxes | 136 | 5 | 5 | — | |
| Net income from oil and gas properties | $ 243 | $ 8 | $ 10 | $ — | |

| | | | | | |
|---|---|---|---|---|---|
| Total operating expenses | | | | | 977 |
| Income from operations | | | | | 407 |
| Interest expense, net of interest income, capitalized interest and other | | | | | (42) |
| Commodity derivative expense | | | | | (43) |
| Income from continuing operations before income taxes | | | | | $ 322 |
| Total long-lived assets | $ 5,159 | $ 313 | $ 74 | $ 1 | $ 5,547 |
| Additions to long-lived assets | $ 1,905 | $ 149 | $ 17 | $ — | $ 2,071 |

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7. Commodity Derivative Instruments:

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

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

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions “Derivative assets” and “Derivative liabilities.” Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model. See Note 14, “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 (expense).” Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

During the first six months of 2008, we entered into a series of transactions that had the effect of resetting all of our then outstanding crude oil hedges for 2009 and 2010. At the time of the reset, the mark-to-market value of these hedge contracts was a liability of $502 million and we paid an additional $56 million to purchase option contracts.

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

At September 30, 2008, we had outstanding contracts with respect to our future production as set forth in the tables below.

Natural Gas

| | | NYMEX Contract Price Per MMBtu | | | | | | | | | Estimated Fair Value Asset |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Collars | | | | | | |
| | | Swaps | Additional Put | | Floors | | Ceilings | | Floors | | |
| Period and Type of Contract | Volume in MMMBtus | (Weighted Average) | Range | Weighted Average | Range | Weighted Average | Range | Weighted Average | Range | Weighted Average | (Liability) (In millions) |
| October 2008 – December 2008 | | | | | | | | | | | |
| Price swap contracts | 9,445 | $ 8.04 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | $ 3 |
| Collar contracts | 15,965 | — | ¾ | ¾ | $ 7.00 – $9.00 | $ 8.03 | $ 9.00 – $17.60 | $ 10.70 | ¾ | ¾ | 11 |
| Floor contracts | 1,860 | — | — | — | ¾ | ¾ | ¾ | ¾ | $ 8.58 - $8.70 | $ 8.64 | 2 |
| 3-Way collar contracts | 6,100 | — | $ 7.00 - $7.50 | $ 7.20 | 8.00 – 9.00 | 8.70 | 11.72 – 20.10 | 13.92 | ¾ | ¾ | 6 |
| January 2009 – March 2009 | | | | | | | | | | | |
| Price swap contracts | 900 | 9.00 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | 1 |
| Collar contracts | 21,150 | — | ¾ | ¾ | 8.00 – 9.00 | 8.09 | 9.67 – 17.60 | 10.88 | ¾ | ¾ | 11 |
| 3-Way collar contracts | 9,000 | — | 7.00 - 7.50 | 7.20 | 8.00 – 9.00 | 8.70 | 11.72 – 20.10 | 13.92 | ¾ | ¾ | 7 |
| April 2009 – June 2009 | | | | | | | | | | | |
| Price swap contracts | 14,685 | 8.42 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | 8 |
| | 13,485 | — | ¾ | ¾ | 8.00 | 8.00 | | 11.83 | ¾ | ¾ | 10 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Collar contracts | | | | | | | 8.97 – 14.37 | | | | |
| July 2009 – September 2009 | | | | | | | | | | | |
| Price swap contracts | 14,820 | 8.42 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | 3 |
| Collar contracts | 13,620 | — | ¾ | ¾ | 8.00 | 8.00 | 8.97 – 14.37 | 11.83 | ¾ | ¾ | 8 |
| October 2009 – December 2009 | | | | | | | | | | | |
| Price swap contracts | 4,985 | 8.42 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | 1 |
| Collar contracts | 8,435 | — | ¾ | ¾ | 8.00 – 8.50 | 8.23 | 8.97 – 14.37 | 11.20 | ¾ | ¾ | 3 |
| January 2010 – March 2010 | | | | | | | | | | | |
| Collar contracts | 5,700 | — | ¾ | ¾ | 8.50 | 8.50 | 10.00 – 11.00 | 10.44 | ¾ | ¾ | ¾ |
| | | | | | | | | | | | $ 74 |

Oil

| | | NYMEX Contract Price Per Bbl | | | | | | | | | Estimated Fair Value Asset |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Collars | | | | | | |
| | Volume in | Swaps (Weighted | Additional Put | Weighted | Floors | Weighted | Ceilings | Weighted | Floors | Weighted | (Liability) |
| Period and Type of Contract | MBbls | Average) | Range | Average | Range | Average | Range | Average | Range | Average | (In millions) |
| October 2008 – December 2008 | | | | | | | | | | | |
| 3-Way collar contracts | 828 | — | $25.00 – $29.00 | $ 26.56 | $32.00 – $35.00 | $ 33.00 | $49.50 – $52.90 | $ 50.29 | — | — | $ (41) |
| January 2009 – December 2009 | | | | | | | | | | | |
| Price swap contracts | 3,285 | $ 128.93 | — | — | — | — | — | — | — | — | 80 |
| Floor contracts | 3,285 | — | — | — | — | — | — | — | $104.50-$[illegible] | $107.51 | 59 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January 2010 – December 2010 | | | | | | | | | | | |
| Price swap contracts | 360 | 93.40 | — | — | — | — | — | — | — | — | (3) |
| Collar contracts | 3,285 | — | — | — | 125.50-[illegible] | [illegible] | 170.00 | 170.00 | — | — | 87 |
| | | | | | | | | | | | $ 182 |

Basis Contracts

At September 30, 2008, we had natural gas basis hedges as set forth in the table below.

| | Onshore Gulf Coast | | Rocky Mountains | | Estimated Fair Value Asset |
|---|---|---|---|---|---|
| | Volume in | Weighted Average | Volume in | Weighted Average | (Liability) |
| | MMBtus | Differential | MMBtus | Differential | (In millions) |
| October 2008 – December 2008 | 7,360 | $ (0.28) | 1,200 | $ (1.62) | $ 3 |
| January 2009 – December 2009 | — | — | 5,520 | $ (1.05) | 8 |
| January 2010 – December 2010 | — | — | 5,520 | $ (0.99) | 11 |
| January 2011 – December 2011 | — | — | 5,280 | $ (0.95) | 6 |
| January 2012 – December 2012 | — | — | 4,920 | $ (0.91) | 2 |
| | | | | | $ 30 |

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

8. Accounts Receivable:

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

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (In millions) | |
| Revenue | $ 224 | $ 142 |
| Joint interest | 153 | 175 |
| Other | 24 | 15 |
| Total accounts receivable | $ 401 | $ 332 |

9. Accrued Liabilities:

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

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (In millions) | |
| Revenue payable | $ 143 | $ 95 |
| Accrued capital costs | 342 | 361 |
| Accrued lease operating expenses | 45 | 38 |
| Employee incentive expense | 74 | 80 |
| Accrued interest on notes | 37 | 19 |
| Taxes payable | 89 | 31 |
| Other | 34 | 47 |
| Total accrued liabilities | $ 764 | $ 671 |

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

10. Comprehensive Income:

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In millions) | | | |
| Net income | $ 724 | $ 83 | $ 416 | $ 137 |
| Unrealized loss on investments, net of tax of $1 for the third quarter of 2008 and $3 for the nine months ended September 30, 2008 | (3) | — | (7) | — |
| Foreign currency translation adjustment, net of tax of $1 for the third quarter of 2007 and ($1) for the nine months ended September 30, 2007 | — | (2) | — | 1 |
| Reclassification adjustments for discontinued cash flow hedges, net of tax of ($1) for the third quarter of 2007 and for the nine months ended September 30, 2007 | — | 2 | — | 2 |
| Reclassification adjustments for settled hedging positions, net of tax of $2 for the nine months ended September 30, 2007 | — | — | — | (3) |
| Changes in fair value of oustanding hedging positions, net of tax of ($4) for the nine months ended September 30, 2007 | — | — | — | 6 |
| Total comprehensive income | $ 721 | $ 83 | $ 409 | $ 143 |

11. Stock-Based Compensation:

We apply SFAS No. 123(R), “Share-Based Payment,” to account for stock-based compensation. 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 shares and restricted share units.

Historically, we have used, and we anticipate continuing to use, unissued shares of stock when stock options are exercised. At September 30, 2008, we had approximately 1.6 million additional shares available for issuance pursuant to our existing employee and director plans. Of these shares, 1.1 million could be granted as restricted shares or restricted share units. Grants of restricted shares and restricted share units under our 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of restricted shares or restricted share units issued. Of the 1.1 million shares that can be granted as restricted shares or restricted share units, 0.7 million of such shares or units can be issued under our 2004 Omnibus Stock Plan.

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

For the three months ended September 30, 2008, we recorded stock-based compensation expense of $9 million (pre-tax) for all plans. Of that amount, $2 million was capitalized in oil and gas properties. For the three months ended September 30, 2007, we recorded stock-based compensation expense of $10 million (pre-tax) for all plans. Of that amount, $3 million was capitalized in oil and gas properties.

For the nine months ended September 30, 2008, we recorded stock-based compensation of $26 million (pre-tax) for all plans. Of that amount, $7 million was capitalized in oil and gas properties. For the nine months ended September 30, 2007, we recorded stock-based compensation of $25 million (pre-tax) for all plans. Of that amount, $7 million was capitalized in oil and gas properties. For the same period, we reported $8 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

As of September 30, 2008, we had approximately $82 million of total unrecognized 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. 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 nine months ended September 30, 2008:

| | Number of Shares Underlying Options (In millions) | Weighted Average Exercise Price per Share | Weighted Average Grant Date Fair Value per Share(1) | Weighted Average Remaining Contractual Life (In years) | Aggregate Intrinsic Value(2) (In millions) |
|---|---|---|---|---|---|
| Outstanding at December 31, 2007 | 3.8 | $ 24.21 | | 5.6 | $ 108 |
| Granted | 0.7 | 48.45 | $ 16.30 | | |
| Exercised | (0.8) | 22.54 | | | 29 |
| Forfeited | (0.2) | 34.89 | | | |
| Outstanding at September 30, 2008 | 3.5 | $ 28.63 | | 5.7 | $ 21 |
| Exercisable at September 30, 2008 | 2.2 | $ 22.36 | | 4.5 | $ 20 |

(1) The fair value of each stock option is estimated as of the date of grant using the Black-Scholes option valuation model, assuming no dividends, a risk-free weighted-average interest rate of 2.83%, an expected life of 5.2 years and weighted-average volatility of 31.7%.

(2) The intrinsic value of a stock option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the option. On September 30, 2008, the last reported sales price of our common stock on the New York Stock Exchange was $31.99 per share.

The following table summarizes information about stock options outstanding and exercisable at September 30, 2008:

| Range of Exercise Prices | Options Outstanding: Number of Shares Underlying Options (In millions) | Options Outstanding: Weighted Average Remaining Contractual Life (In years) | Options Outstanding: Weighted Average Exercise Price per Share | Options Exercisable: Number of Shares Underlying Options (In millions) | Options Exercisable: Weighted Average Exercise Price per Share |
|---|---|---|---|---|---|
| $ 12.51 to $15.00 | 0.2 | 1.3 | $ 14.79 | 0.2 | $ 14.79 |
| 15.01 to 17.50 | 0.6 | 3.8 | 16.63 | 0.6 | 16.63 |
| 17.51 to 22.50 | 0.4 | 3.6 | 18.98 | 0.4 | 18.92 |
| 22.51 to 27.50 | 0.5 | 5.4 | 24.77 | 0.4 | 24.77 |
| 27.51 to 35.00 | 1.0 | 6.2 | 31.14 | 0.5 | 31.02 |
| 35.01 to 41.72 | 0.2 | 6.6 | 38.00 | 0.1 | 38.08 |
| 41.73 to 48.45 | 0.6 | 9.4 | 48.45 | — | ¾ |
| | 3.5 | 5.7 | $ 28.63 | 2.2 | $ 22.36 |

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

Restricted Shares. At September 30, 2008, our employees held 1.9 million restricted shares or restricted share units that primarily vest over a service period of four or five years. The vesting of these shares and units is dependant upon the employee's continued service with our company. In addition, at September 30, 2008, our employees held 0.9 million restricted shares subject to performance-based vesting criteria (substantially all of which are considered market-based restricted shares under SFAS No. 123(R)).

The following table provides information about restricted share and restricted share unit activity for the nine months ended September 30, 2008:

| | 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, 2007 | 1,161 | 1,614 | 2,775 | $ 29.77 |
| Granted | 893 | — | 893 | 44.06 |
| Forfeited | (82) | (700) | (782) | 32.05 |
| Vested | (44) | (1) | (45) | 40.48 |
| Non-vested shares outstanding at September 30, 2008 | 1,928 | 913 | 2,841 | $ 33.46 |

The total fair value of restricted shares that vested during the nine months ended September 30, 2008 was $1.8 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 third quarter of 2008, options to purchase 25,552 shares of our common stock at a weighted average fair value of $18.39 per share were issued under the plan. 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 2.13%, an expected life of six months and weighted average volatility of 46.21%. At September 30, 2008, 575,671 shares of our common stock remained available for issuance under the plan.

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

12. Income Taxes:

The Company's interim period tax provision has been calculated based on statutory tax rates applied to pre-tax earnings as adjusted for permanent differences. An annualized projected effective tax rate has not been applied because of our inability to develop a reliable estimate of our pre-tax income, which is subject to significant variability due to changes in the fair value of our open commodity derivative instruments. This could result in significant variations in the reported tax provision in the interim periods. The effective tax rates for the third quarter of 2008 and 2007 were 31.7% and 40.2%, respectively. The effective tax rates for the first nine months of 2008 and 2007 were 37.3% and 38.8%, respectively. Our effective tax rates were different than our federal statutory tax rate due to foreign and state income taxes associated with income from various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

13. Discontinued Operations:

In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash and recorded a gain of $341 million. As a result, the historical results of operations and financial position of our U.K. North Sea operations are reflected in our financial statements as "discontinued operations."

The summarized financial results of the discontinued operations are as follows:

| | Three Months Ended September 30, 2007 | Nine Months Ended September 30, 2007 |
|---|---|---|
| | (In millions) | |
| Revenues | $ 5 | $ 8 |
| Operating expenses (1) | 8 | 61 |
| Loss from operations | (3) | (53) |
| Commodity derivative expense | (3) | (3) |
| Other expense (2) | (3) | (4) |
| Loss before income taxes | (9) | (60) |
| Income tax benefit | — | — |
| Loss from discontinued operations, net of tax | $ (9) | $ (60) |

(1) Operating expenses for the nine months ended September 30, 2007 include a ceiling test writedown of $47 million recorded in the first quarter of 2007.

(2) Other expense primarily consists of U.K. withholding tax expense with respect to interest on intercompany loans.

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

14. Fair Value Measurements:

We adopted SFAS No. 157, "Fair Value Measurements," effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FSP No.157-2, which delayed the effective date of SFAS No.157 by one year for non-financial assets and liabilities. As defined in SFAS No.157, 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). SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement 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, 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 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. |

As required by SFAS No. 157, 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. The following table summarizes the valuation of our investments and financial instruments by SFAS No. 157 pricing levels as of September 30, 2008:

| | 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) | | | |
| Assets (Liabilities): | | | | |
| Investments | $ 4 | $ 6 | $ 68 | $ 78 |
| Oil and gas derivative swap contracts | — | 93 | 30 | 123 |
| Oil and gas derivative option contracts | — | — | 163 | 163 |
| Interest rate swaps | — | 1 | — | 1 |
| Total | $ 4 | $ 100 | $ 261 | $ 365 |

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

The determination of the fair values above incorporates various factors required under SFAS No. 157. These factors include not only the impact of our nonperformance 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 September 30, 2008, we continued to hold $68 million of auction rate securities that are classified as a Level 3 fair value measurement. This amount reflects a decrease in the fair value of these investments of $7 million, recorded under the caption "Accumulated other comprehensive income (loss)" on our consolidated balance sheet. Since there has been no effective mechanism for selling these securities, we reclassified them from short-term investments to long-term investments during the second quarter of 2008. The debt instruments underlying these investments are investment grade (rated A 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 have the ability and intent to hold these investments until the auction succeeds, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

The following 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 (in millions):

Three Months Ended September 30, 2008:

| | Investments | Derivatives | Total |
|---|---|---|---|
| Balance at June 30, 2008 | $ 69 | $ (283) | $ (214) |
| Total realized or unrealized gains or (losses): | | | |
| Included in earnings | — | 415 | 415 |
| Included in other comprehensive income | (1) | — | (1) |
| Purchases, issuances and settlements | — | 61 | 61 |
| Transfers in and out of Level 3 | — | — | — |
| Balance at September 30, 2008 | $ 68 | $ 193 | $ 261 |

Nine Months Ended September 30, 2008:

| | Investments | Derivatives | Total |
|---|---|---|---|
| Balance at January 1, 2008 | $ 120 | $ (341) | $ (221) |
| Total realized or unrealized gains or (losses): | | | |
| Included in earnings | — | (193) | (193) |
| Included in other comprehensive income | (7) | — | (7) |
| Purchases, issuances and settlements (1) | (45) | 727 | 682 |
| Transfers in and out of Level 3 | — | — | — |
| Balance at September 30, 2008 | $ 68 | $ 193 | $ 261 |
| Change in unrealized gains (losses) relating to investments and derivatives still held at September 30, 2008 | $ (7) | $ 161 | $ 154 |

(1) Derivative settlements include $502 million we paid to reset a portion of our oil hedging contracts for 2009 and 2010.

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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 natural gas and crude oil 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.

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.

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. We did not have a ceiling test writedown at September 30, 2008. Holding all other factors constant, if the applicable index for oil and gas prices were to drop to levels below the current levels, it is possible that we could experience a ceiling test writedown of our oil and gas properties at December 31, 2008. In addition, given current market conditions it is reasonably possible that some or all of our goodwill could be impaired in the future.

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

Accounting for Hedging Activities. We do not designate any price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of September 30, 2008, we had a net derivative asset of $286 million, of which 67% was measured based upon our valuation model 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 7, "Commodity Derivative Instruments," and Note 14, "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, 2007 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.

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Results of Operations

Significant Transactions. We completed several significant transactions during 2008 and 2007 that affect the comparability of our results of operations and cash flows from period to period.

- During the first six months of 2008, we entered into a series of transactions that had the effect of resetting all of our then outstanding crude oil hedges for 2009 and 2010. At the time of the reset, the mark-to-market value of these hedge contracts was a liability of $502 million and we paid an additional $56 million to purchase option contracts.

- In June 2007, we acquired Stone Energy Corporation's Rocky Mountain assets for $578 million in cash. Initially, we financed this acquisition through borrowings under our revolving credit agreement.

- In August 2007, we sold our shallow water Gulf of Mexico assets for $1.1 billion in cash and the purchaser's assumption of liabilities associated with future abandonment of wells and platforms.

- In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash. The historical results of operations of our U.K. North Sea operations are reflected in our financial statements as "discontinued operations." Except where noted, discussions in this report relate to continuing operations only.

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 revenues, but those not so designated have no effect on our reported revenues. None of our outstanding hedges are designated for hedge accounting. Please see Note 7, "Commodity Derivative 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 $0.7 billion for the third quarter of 2008 were 63% higher than the comparable period of 2007 due to significantly higher average realized oil and gas prices and higher oil production partially offset by lower gas production. Revenues for the first nine months of 2008 were 36% higher than the same period of the prior year due to significantly higher average realized oil and gas prices and higher oil production, which was slightly offset by lower gas production.

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| | Three Months Ended September 30, 2008 | 2007 | Percentage Increase (Decrease) | Nine Months Ended September 30, 2008 | 2007 | Percentage Increase (Decrease) |
|---|---|---|---|---|---|---|
| Production (1): | | | | | | |
| United States: | | | | | | |
| Natural gas (Bcf) | 44.9 | 46.9 | (4)% | 129.0 | 154.9 | (17)% |
| Oil and condensate (MBbls) | 1,617 | 1,669 | (3)% | 4,567 | 5,285 | (14)% |
| Total (Bcfe) | 54.7 | 56.9 | (4)% | 156.4 | 186.6 | (16)% |
| International: | | | | | | |
| Natural gas (Bcf) | — | — | — | — | — | — |
| Oil and condensate (MBbls) | 1,124 | 488 | 130% | 2,954 | 1,401 | 111% |
| Total (Bcfe) | 6.7 | 2.9 | 130% | 17.7 | 8.4 | 111% |
| Total: | | | | | | |
| Natural gas (Bcf) | 44.9 | 46.9 | (4)% | 129.0 | 154.9 | (17)% |
| Oil and condensate (MBbls) | 2,741 | 2,157 | 27% | 7,521 | 6,686 | 12% |
| Total (Bcfe) | 61.4 | 59.8 | 3% | 174.1 | 195.0 | (11)% |
| | | | | | | |
| Average Realized Prices (2): | | | | | | |
| United States: | | | | | | |
| Natural gas (per Mcf) | $ 8.67 | $ 5.81 | 49% | $ 8.72 | $ 6.38 | 37% |
| Oil and condensate (per Bbl) | 105.46 | 65.71 | 60% | 100.91 | 57.03 | 77% |
| Natural gas equivalent (per Mcfe) | 10.25 | 6.71 | 53% | 10.14 | 6.91 | 47% |
| International: | | | | | | |
| Natural gas (per Mcf) | $ — | $ — | — | $ — | $ — | — |
| Oil and condensate (per Bbl) | 106.87 | 71.96 | 49% | 100.93 | 62.91 | 60% |
| Natural gas equivalent (per Mcfe) | 17.81 | 11.99 | 49% | 16.82 | 10.49 | 60% |
| Total: | | | | | | |
| Natural gas (per Mcf) | $ 8.67 | $ 5.81 | 49% | $ 8.72 | $ 6.38 | 37% |
| Oil and condensate (per Bbl) | 106.04 | 67.13 | 58% | 100.92 | 58.26 | 73% |
| Natural gas equivalent (per Mcfe) | 11.08 | 6.97 | 59% | 10.82 | 7.07 | 53% |

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

(2) Average realized prices only include the effects of hedging contracts that are designated for hedge accounting. Had we included the effects of contracts not so designated, our average realized price for total gas would have been $7.25 and $7.52 per Mcf for the third quarter of 2008 and 2007, respectively, and $7.69 and $7.72 per Mcf for the nine months ended September 30, 2008 and 2007, respectively. Our total oil and condensate average realized price would have been $85.44 and $57.89 per Bbl for the third quarter of 2008 and 2007, respectively, and $80.12 and $52.83 per Bbl for the nine months ended September 30, 2008 and 2007, respectively. All amounts for the nine months ended September 30, 2008 exclude the cash payments to reset our 2009 and 2010 crude oil hedges of $502 million.

Domestic Production. Our third quarter and year-to-date 2008 domestic gas and oil production (stated on a natural gas equivalent basis) decreased as compared to the comparable periods of 2007 as a result of the sale of our shallow water Gulf of Mexico assets in August 2007. In addition, the third quarter of 2008 includes the deferral of approximately 2 Bcfe related to the recent hurricanes in the Gulf of Mexico. This decrease was partially offset by an increase in 2008 production in the Mid-Continent as a result of continued successful drilling efforts.

International Production. Our third quarter and year-to-date 2008 international production increased over the comparable periods of 2007 primarily due to new field developments on PM 318 and PM 323 in Malaysia.

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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. However, because of the several significant transactions we completed in 2007 (see above) and the significant increase in our international production, period to period comparisons are difficult. For example, offshore Gulf of Mexico properties typically have significantly higher lease operating costs relative to onshore properties and offshore production is not subject to production taxes but onshore production is subject to these taxes.

The following table presents information about our operating expenses for the third quarter of 2008 and 2007.

| | Unit-of-Production Three Months Ended September 30, | | Percentage Increase (Decrease) | Total Amount Three Months Ended September 30, | | Percentage Increase (Decrease) |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | | 2008 | 2007 | |
| | (Per Mcfe) | | | (In millions) | | |
| United States: | | | | | | |
| Lease operating | $ 0.99 | $ 0.96 | 3% | $ 54 | $ 54 | — |
| Production and other taxes | 0.38 | 0.35 | 8% | 21 | 20 | 4% |
| Depreciation, depletion and amortization | 2.81 | 2.69 | 4% | 154 | 153 | — |
| General and administrative | 0.63 | 0.61 | 4% | 35 | 35 | — |
| Total operating expenses | $ 4.81 | $ 4.61 | 4% | $ 264 | $ 262 | — |
| International: | | | | | | |
| Lease operating | $ 1.94 | $ 3.30 | (41)% | $ 13 | $ 10 | 36% |
| Production and other taxes | 4.46 | 1.75 | 154% | 30 | 5 | 485% |
| Depreciation, depletion and amortization | 3.95 | 2.99 | 32% | 27 | 9 | 204% |
| General and administrative | 0.23 | 0.75 | (69)% | 1 | 2 | (28)% |
| Total operating expenses | $ 10.58 | $ 8.79 | 20% | $ 71 | $ 26 | 177% |
| Total: | | | | | | |
| Lease operating | $ 1.10 | $ 1.07 | 3% | $ 67 | $ 64 | 5% |
| Production and other taxes | 0.82 | 0.42 | 98% | 51 | 25 | 103% |
| Depreciation, depletion and amortization | 2.94 | 2.71 | 9% | 181 | 162 | 11% |
| General and administrative | 0.59 | 0.62 | (5)% | 36 | 37 | (2)% |
| Total operating expenses | $ 5.45 | $ 4.82 | 13% | $ 335 | $ 288 | 16% |

Domestic Operations. Our domestic total operating expenses for the third quarter of 2008, stated on an Mcfe basis, increased 4% over the same period of 2007. The period to period change was primarily due to the following:

- Lease operating expense (LOE) increased 3% per Mcfe due to higher operating costs for all of our operations in 2008 offset by a decrease due to the sale of all of our producing properties in the shallow water Gulf of Mexico in August 2007, which properties have relatively high LOE per Mcfe.

- Production and other taxes increased $0.03 per Mcfe because of increased production from our Mid-Continent and Rocky Mountain operations, which are subject to production taxes, the sale of our Gulf of Mexico properties, which were not subject to production taxes, and increased commodity prices. This increase was significantly reduced by refunds of $7 million ($0.13 per Mcfe) related to production tax exemptions on some of our onshore high cost gas wells recorded in the third quarter of 2008 compared to refunds of $2 million

($0.03 per Mcfe) recorded during the third quarter of 2007.

- Our depreciation, depletion and amortization (DD&A) rate increased 4% per Mcfe period over period as a result of higher cost reserve additions, offset by the amount of the proceeds from the sale of our Gulf of Mexico properties in August 2007 and the sale of our coal bed methane assets in the Cherokee Basin in September 2007. In addition, accretion expense decreased period over period due to the significant reduction in our asset retirement obligation following the sale of our Gulf of Mexico properties.

- General and administrative (G&A) expense increased 4% per Mcfe primarily due to continued growth in our workforce. G&A expense includes incentive compensation expense, which is calculated based on adjusted net income (as defined in our incentive compensation plan). Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. During the third quarter of 2008, we capitalized $13 million of direct internal costs as compared to $12 million in 2007.

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International Operations. Our international operating expenses for the third quarter of 2008, stated on an Mcfe basis, increased 20% over the same period of 2007. The period to period change was primarily related to the following items:

- LOE decreased 41% per Mcfe while total LOE increased 36% over the comparable period of 2007. The increase in total LOE expense was primarily due to new field developments on PM 318 and PM 323 and higher operating costs in Malaysia.

- Production and other taxes increased significantly due to an increase in the tax on our oil lifted and sold in Malaysia as a result of substantially higher oil prices.

- The DD&A rate on an Mcfe basis increased 32% over the comparable period of 2007 as a result of higher cost reserve additions in Malaysia.

- G&A expense decreased $0.52 per Mcfe primarily due to increased production in Malaysia.

The following table presents information about our operating expenses for the first nine months of 2008 and 2007.

| | Unit-of-Production | | | Total Amount | | |
|---|---|---|---|---|---|---|
| | Nine Months Ended September 30, | | Percentage Increase | Nine Months Ended September 30, | | Percentage Increase |
| | 2008 | 2007 | (Decrease) | 2008 | 2007 | (Decrease) |
| | (Per Mcfe) | | | (In millions) | | |
| United States: | | | | | | |
| Lease operating | $ 0.94 | $ 1.31 | (28)% | $ 147 | $ 245 | (40)% |
| Production and other taxes | 0.41 | 0.28 | 50% | 64 | 51 | 26% |
| Depreciation, depletion and amortization | 2.80 | 2.77 | 1% | 438 | 517 | (15)% |
| General and administrative | 0.65 | 0.56 | 16% | 101 | 104 | (3)% |
| Total operating expenses | $ 4.80 | $ 4.92 | (2)% | $ 750 | $ 917 | (18)% |
| International: | | | | | | |
| Lease operating | $ 2.10 | $ 2.69 | (22)% | $ 37 | $ 23 | 65% |
| Production and other taxes | 5.05 | 1.40 | 260% | 90 | 12 | 658% |
| Depreciation, depletion and amortization | 3.72 | 2.65 | 40% | 66 | 22 | 196% |
| General and administrative | 0.21 | 0.36 | (43)% | 4 | 3 | 21% |
| Total operating expenses | $ 11.08 | $ 7.10 | 56% | $ 197 | $ 60 | 229% |
| Total: | | | | | | |
| Lease operating | $ 1.06 | $ 1.37 | (23)% | $ 184 | $ 268 | (31)% |
| Production and other taxes | 0.88 | 0.32 | 173% | 154 | 63 | 144% |
| Depreciation, depletion and amortization | 2.89 | 2.76 | 5% | 504 | 539 | (7)% |
| General and administrative | 0.60 | 0.55 | 9% | 105 | 107 | (2)% |
| Total operating expenses | $ 5.43 | $ 5.00 | 8% | $ 947 | $ 977 | (3)% |

Domestic Operations. Our domestic operating expenses for the first nine months of 2008, stated on an Mcfe basis, decreased 2% over the same period of 2007. The period to period change was primarily related to the following items:

- LOE decreased 28% per Mcfe due to the sale of our shallow water Gulf of Mexico properties in August 2007, which properties had relatively high LOE per Mcfe. In addition, our 2007 LOE was adversely impacted by repair expenditures of $53 million ($0.28 per Mcfe) related to Hurricanes Katrina and Rita in 2005. Without the impact of the repair expenditures related to these storms, our 2007 LOE would have been $1.03 per Mcfe. The decrease in LOE was partially offset by higher operating costs in 2008 for all of our operations.

- Production and other taxes increased 50% per Mcfe because of increased production from our Mid-Continent and Rocky Mountain operations, which are subject to production taxes, the sale of our Gulf of Mexico properties, which were not subject to production taxes, and increased commodity prices. This increase was partially offset by refunds of $20 million ($0.13 per Mcfe) related to production tax exemptions on some of our onshore high cost gas wells recorded during the first nine months of 2008 compared to refunds of $8 million ($0.04 per Mcfe) recorded during the first nine months of 2007.

- Our DD&A rate per Mcfe remained flat period over period. Total DD&A expense decreased 15% period over period primarily due to the sale of our Gulf of Mexico properties in August 2007. In addition, accretion expense decreased period over period due to the significant reduction in our asset retirement obligation following the sale of our Gulf of Mexico properties. The decrease in total DD&A expense was partially offset by higher DD&A expense associated with the increased production from our Mid-Continent and Rocky Mountain divisions.

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- G&A expense increased 16% per Mcfe while total G&A expense decreased 3% over the comparable period of 2007. The decrease in total G&A expense was primarily due to recording a litigation settlement reserve associated with a statewide royalty owner class action lawsuit in Oklahoma in the first quarter of 2007 partially offset by increased employee related expenses in 2008 due to our increased domestic workforce and increased incentive compensation expense. Incentive compensation expense increased as a result of higher adjusted net income (as defined in our incentive compensation plan) for the first nine months of 2008 as compared to the same period of the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. For purposes of the incentive compensation plan, we did not include the effects of resetting our 2009 and 2010 crude oil hedging positions in the second quarter of 2008, but will match those hedge results with production in the respective periods. During the first nine months of 2008, we capitalized $37 million of direct internal costs as compared to $33 million for the same period in 2007.

International Operations. Our international operating expenses for the first nine months of 2008, stated on an Mcfe basis, increased 56% over the same period of 2007. The period to period change was primarily related to the following items:

- LOE decreased 22% per Mcfe while total LOE increased 65% over the comparable period of 2007. The decrease on a per unit basis resulted from increased liftings in Malaysia. The increase in total LOE was primarily due to new field developments on PM 318 and PM 323 and higher operating costs in Malaysia.

- Production and other taxes increased significantly due to an increase in the tax on our oil lifted and sold in Malaysia as a result of substantially higher oil prices.

- The DD&A rate increased as a result of higher cost reserve additions in Malaysia.

- G&A expense decreased 43% per Mcfe primarily due to increased production in Malaysia.

Commodity Derivative Income (Expense)

Commodity derivative income during the third quarter of 2008 increased $688 million over the same period of 2007, while the change for the nine month period ended September 30, 2008 as compared to the same period of 2007 was an increase in commodity derivative expense of $204 million. The significant fluctuation in these amounts is due to the extreme volatility of crude oil and natural gas prices during these periods.

Interest Expense

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (In millions) | | | |
| Gross interest expense: | | | | |

| | | | | |
|---|---|---|---|---|
| Credit arrangements | $ 7 | $ 6 | $ 10 | $ 13 |
| Senior notes | 3 | 6 | 10 | 18 |
| Senior subordinated notes | 26 | 15 | 61 | 44 |
| Other | — | 2 | 2 | 5 |
| Total gross interest expense | 36 | 29 | 83 | 80 |
| Capitalized interest | (16) | (13) | (43) | (35) |
| Net interest expense | $ 20 | $ 16 | $ 40 | $ 45 |

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Gross interest expense for the third quarter of 2008 increased 25% and for the first nine months of 2008 increased slightly when compared to the same periods in 2007. Interest expense for the third quarter and first nine months of 2008 included interest on our 7 1/8% Senior Subordinated Notes issued on May 5, 2008. The third quarter and first nine months of 2007 included interest expense on our 7.45% Senior Notes that matured in October 2007. During the first nine months of 2007, we also incurred higher interest expense due to higher average debt levels outstanding under our credit arrangements.

We capitalize interest with respect to our unproved properties. Interest capitalized during the third quarter and first nine months of 2008 increased over the same periods in 2007 due to an increase in our unproved property base primarily as a result of the Rocky Mountain asset acquisition in June 2007.

Taxes. The effective tax rates for the third quarter of 2008 and 2007 were 31.7% and 40.2%, respectively. The effective tax rates for the first nine months of 2008 and 2007 were 37.3% and 38.8%, respectively. Our effective tax rates are different than our federal statutory tax rate primarily due to foreign and state income taxes associated with income from the various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

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. Our 2008 capital budget exceeds expected full year net cash flow from operations and cash on hand. As a result, we anticipate additional borrowings under our credit arrangements of approximately $100 million during the remainder of 2008 . We have adequate capacity under our credit arrangements to fund the shortfall.

In light of the current economic outlook and commodity prices, we intend to limit our 2009 capital expenditures to a level that can be funded with cash flow from operations, thereby preserving liquidity under our credit arrangements. Our 2009 capital budget will focus on those projects that we believe will generate and lay the foundation for production growth. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

We continued to hold auction rate securities with a fair value of $68 million. We will continue to attempt to sell these securities every 7-28 days until the auction succeeds, 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.

Credit Arrangements. In June 2007, we entered into a new revolving credit facility that matures in June 2012 and provides for initial loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent. As of September 30, 2008, the largest commitment by a single member of the syndicate was 8% of total commitments. Total loan commitments may 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. Subject to compliance with covenants in our credit facility that restrict our ability to incur additional debt, we also have a total of $135 million of borrowing capacity under money market lines of credit with various financial institutions. For a more detailed description of the terms of our credit arrangements, please see Note 4, “Debt – Credit Arrangements,” to our consolidated financial statements appearing earlier in this report.

At October 21, 2008, we had outstanding borrowings of $395 million under our credit arrangements and we had approximately $964 million of available borrowing capacity under our credit arrangements.

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 because our capital spending generally has exceeded our cash flows from operations and we generally use excess cash to pay down borrowings outstanding under our credit arrangements.

At September 30, 2008, we had a working capital deficit of $203 million compared to a deficit of $2 million at December 31, 2007. During the first nine months of 2008, we utilized $260 million of our cash and short-term investments on hand at the beginning of 2008 to fund a portion of our capital program and reclassified $75 million of our auction rate securities from short-term to long-term investments. The working capital deficit at September 30, 2008 was somewhat offset by an increase of $69 million in accounts receivable primarily resulting from higher oil and gas prices and increased production. In addition, at September 30, 2008, we had a net short-term derivative asset of $146 million compared to a net short-term derivative liability of $84 million at December 31, 2007.

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Cash Flows from Operations. Cash flows from operations (both continuing and discontinued) 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 natural gas and oil production under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months. See "Oil and Gas Hedging" below.

We typically receive the cash associated with accrued 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 is impacted by changes in working capital and is not affected by DD&A, writedowns or other non-cash charges or credits.

Our net cash flow from operations was $622 million for the nine months ended September 30, 2008, a decrease of 33% compared to net cash flow from operations of $931 million for the same period in 2007. This decrease is primarily due to the payment of $557 million to reset our 2009 and 2010 crude oil hedging contracts. Even though our nine months ended September 30, 2008 production volumes were impacted by our 2007 property sales, this impact was somewhat offset by higher commodity prices during the first nine months of 2008, increased production from our Mid-Continent and Rocky Mountain divisions and increased liftings in Malaysia. In addition, our working capital requirements during the nine months ended September 30, 2008 decreased compared to the same period in 2007 as a result of the timing of receivable collections from purchasers, the timing of payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Investing Activities. Net cash used in investing activities (both continuing and discontinued) for the nine months ended September 30, 2008 was $1.7 billion compared to $0.9 billion for the same period in 2007.

During the nine months ended September 30, 2008, we:

- spent $1.8 billion primarily on capital expenditures (including $231 million for acquisitions of oil and gas properties); and
- purchased investments of $22 million and redeemed investments of $70 million.

During the nine months ended September 30, 2007, we:

- spent $2.1 billion primarily on capital expenditures (including $578 million for the Rocky Mountain asset acquisition);
- received proceeds of $1.3 billion from the sale of U.S. oil and gas properties; and
- purchased investments of $43 million and redeemed investments of $24 million.

Capital Expenditures. Our capital spending for the first nine months of 2008 was $1.8 billion, a 15% decrease from our $2.1 billion in capital spending during the same period of 2007. These amounts exclude recorded asset retirement costs of $3 million in 2008 and $16 million in 2007. Of the $1.8 billion spent in 2008, we invested $963 million in domestic exploitation and development, $275 million in domestic exploration (exclusive of exploitation and leasehold activity), $346 million in domestic leasehold activity (includes the acquisition of properties in South Texas) and $171 million internationally. Of the $2.1 billion spent in the first nine months of 2007, we invested $1.1 billion in domestic exploitation and development, $182 million in domestic exploration (exclusive of exploitation and leasehold activity), $646 million for acquisitions and domestic leasehold activity (including $578 million for the Rocky

Mountain assets acquired from Stone Energy) and $165 million internationally.

Our 2008 capital budget is $2.2 billion. The budget excludes $115 million of capitalized interest and overhead. Approximately 35% of the capital budget is allocated to the Mid-Continent, 15% to the Rocky Mountains, 40% to onshore Texas and the Gulf of Mexico and 10% to international projects. Since our 2008 capital budget exceeds forecasted net cash flow from operations, we have made up the shortfall with cash on hand and borrowings under our credit arrangements. We anticipate funding the remaining $500 million of our 2008 capital program with cash flows from operations and borrowings under our credit arrangements.

In light of the current economic outlook and commodity prices, we intend to limit our 2009 capital expenditures to a level that can be funded with cash flow from operations, thereby preserving liquidity under our credit arrangements. Our 2009 capital budget, which at this time is expected to be approximately $1.65 billion, will focus on those projects that we believe will generate and lay the foundation for production growth. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations. Actual levels of capital expenditures in any year may vary significantly due to many factors, including the extent to which properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services.

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Cash Flows from Financing Activities. Net cash flow provided by financing activities (both continuing and discontinued) for the first nine months of 2008 was $895 million compared to $25 million of net cash flow provided by financing activities for the same period in 2007.

During the first nine months of 2008, we:

- borrowed $1.8 billion and repaid $1.5 billion under our credit arrangements;
- issued $600 million aggregate principal amount of our 7 1/8% Senior Subordinated Notes due 2018 and paid $8 million in associated debt issue costs; and
- received proceeds of $18 million from the issuance of shares of our common stock upon the exercise of stock options.

During the first nine months of 2007, we:

- borrowed and repaid $2.9 billion under our credit arrangements;
- received proceeds of $18 million from the issuance of shares of our common stock upon the exercise of stock options; and
- received an $8 million tax benefit from the exercise of stock options.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of September 30, 2008.

| | Total | Less than 1 Year | 1-3 Years | 4-5 Years | More than 5 Years |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| Debt: | | | | | |
| Bank revolving credit facility | $ 285 | $ — | $ — | $ 285 | $ — |
| 7 5/8% Senior Notes due 2011 | 175 | — | 175 | — | — |
| 6 5/8% Senior Subordinated Notes due 2014 | 325 | — | — | — | 325 |
| 6 5/8% Senior Subordinated Notes due 2016 | 550 | — | — | — | 550 |
| 7 1/8% Senior Subordinated Notes due 2018 | 600 | — | — | — | 600 |
| Total debt | 1,935 | — | 175 | 285 | 1,475 |
| | | | | | |
| Other obligations: | | | | | |
| Interest payments(1) | 934 | 129 | 249 | 212 | 344 |
| Net derivative liabilities (assets) | (286) | (141) | (140) | (5) | — |
| Asset retirement obligations | 68 | 7 | 6 | 6 | 49 |
| Operating leases | 170 | 95 | 37 | 14 | 24 |
| Deferred acquisition payments | 2 | 2 | — | — | — |
| Oil and gas activities(2) | 663 | — | — | — | — |
| Total other obligations | 1,551 | 92 | 152 | 227 | 417 |

| | | | | | |
|---|---|---|---|---|---|
| Total contractual obligations | $ 3,486 | $ 92 | $ 327 | $ 512 | $ 1,892 |

(1) Interest associated with our revolving credit facility was calculated using a weighted average interest rate for LIBOR based loans of 4.913% at September 30, 2008 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 September 30, 2008, these work-related commitments totaled $663 million and were comprised of $613 million in the United States and $50 million internationally. A significant portion of the United States amount is related to a 10-year firm transportation agreement for our Mid-Continent production. This obligation is subject to the completion of construction and required regulatory approvals of the proposed pipeline. Annual amounts are not included because their timing cannot be accurately predicted.

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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 natural gas production for the next 12-24 months to reduce our exposure to fluctuations in natural gas and oil 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. 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. At September 30, 2008, J Aron & Company, Barclay's Capital, JPMorgan Chase, Bank of America, Bank of Montreal and Citibank N.A. were the counterparties with respect to 84% of our future hedged production. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, a majority of our hedged natural gas and crude oil production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges. With the sale of our Gulf of Mexico shelf production and the corresponding shift in the geographic distribution of our natural gas production, we have begun to utilize basis hedges to a greater extent.

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 $0.40-$0.60 per MMBtu less than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 75-85% of the Henry Hub Index. In light of potential basis risk with respect to our newly acquired Rocky Mountain assets, we have hedged the basis differential for about 50% of our estimated production from proved producing fields acquired from Stone Energy through 2012 to lock in the differential at a weighted average of $1.18 per MMBtu less than the Henry Hub Index. The price we receive for our Gulf Coast oil production typically equals the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about $15 per barrel below the WTI price. Oil production from the Mid-Continent typically averages 96-98% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 90% of WTI. Oil sales from our operations in China typically sell at $10-$15 per barrel less than the WTI price.

Between September 30, 2008 and October 23, 2008, we entered into additional natural gas price derivative contracts set forth in the table below.

| Period and Type of Contract | Volume in MMMBtus | Weighted Average NYMEX Contract Price per MMBtu |
|---|---|---|
| April 2009 – June 2009 | | |
| Price swap contracts | 1,820 | $ 7.59 |
| July 2009 – September 2009 | | |

| | | |
|---|---|---|
| Price swap contracts | 1,840 | 7.59 |
| October 2009 – December 2009 | | |
| Price swap contracts | 4,280 | 8.41 |
| January 2010 – March 2010 | | |
| Price swap contracts | 5,400 | 8.55 |
| April 2010 – June 2010 | | |
| Price swap contracts | 1,820 | 8.01 |
| July 2010 – September 2010 | | |
| Price swap contracts | 1,840 | 8.01 |
| October 2010 | | |
| Price swap contracts | 620 | 8.01 |

New Accounting Standards

In March 2008, the Financial Accounting Standards Board issued FASB Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (SFAS No. 161). This statement requires enhanced disclosures about our derivative and hedging activities. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We will adopt SFAS No. 161 beginning January 1, 2009. We are currently evaluating the impact, if any, the statement will have on our consolidated financial statements.

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## General Information

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

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

## Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results such as planned capital expenditures, the availability and source 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:

- drilling results;
- oil and gas prices;
- industry conditions;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- the availability of refining capacity for crude oil we produce from our Monument Butte Field;
- the availability of capital resources;
- labor conditions;
- severe weather conditions (such as hurricanes); 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, 2007.

All written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by such factors.

## 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.

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

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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. A well drilled to find and produce oil or natural gas reserves that is not a development 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.

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.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

MMcf. One million cubic feet.

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

NYMEX. The New York Mercantile Exchange.

Probable reserves. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

Proved reserves. In general, the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

## 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 natural gas and oil prices. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage return 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 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 7, "Commodity Derivative Instruments," to our consolidated financial statements appearing earlier in this report.

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Interest Rates

At September 30, 2008, our debt was comprised of:

| | Fixed Rate Debt | Variable Rate Debt |
|---|---|---|
| | (In millions) | |
| Bank revolving credit facility | $ — | $ 285 |
| Money market lines of credit | — | — |
| 7 5/8% Senior Notes due 2011(1) | 125 | 50 |
| 6 5/8% Senior Subordinated Notes due 2014 | 325 | — |
| 6 5/8% Senior Subordinated Notes due 2016 | 550 | — |
| 7 1/8% Senior Subordinated Notes due 2018 | 600 | — |
| Total long-term debt | $ 1,600 | $ 335 |

(1) $50 million principal amount of our 7 5/8% Senior Notes due 2011 are subject to interest rate swaps. These swaps provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes.

We consider our interest rate exposure to be minimal because about 83% of our long-term debt, after taking into account our interest rate swaps, is 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 September 30, 2008.

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 the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2008 in ensuring that material information was accumulated and communicated to management, and made known to our Chief Executive Officer and Chief Financial Officer, on a timely basis to allow disclosure as required in this report.

Changes in Internal Control Over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the third quarter of 2008 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 or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II

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

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended September 30, 2008.

| Period | Total Number of Shares Purchased(1) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| July 1 – July 31, 2008 | 265 | $ 65.57 | — | — |
| August 1 - August 31, 2008 | 1,084 | $ 48.97 | — | — |
| September 1 - September 30, 2008 | 754 | $ 45.55 | — | — |

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards. 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 |
|---|---|
| 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.

SIGNATURE

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

| | | |
|---|---|---|
| | NEWFIELD EXPLORATION COMPANY | |
| Date: October 24, 2008 | By: | /s/ TERRY W. RATHERT<br>Terry W. Rathert<br>Senior Vice President and Chief Financial Officer |

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EXHIBIT INDEX

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* Filed or furnished herewith.