# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 10-Q

**☒ Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**For the quarterly period ended March 31, 2011**

**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 1-9735**

# BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

| **DELAWARE** | **77-0079387** |
|---|---|
| (State of incorporation or organization) | (I.R.S. Employer Identification Number) |

**1999 Broadway, Suite 3700**
**Denver, Colorado 80202**
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **(303) 999-4400**

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 ☒ NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ☒ 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer ☒ | Accelerated filer o |
| Non-accelerated filer o | 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 ☒

As of April 21, 2011 the registrant had 51,557,180 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock ($.01 par value) outstanding on April 21, 2011, all of which is held by an affiliate of the registrant.

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**BERRY PETROLEUM COMPANY**

**Condensed Balance Sheets**

**(Unaudited)**

**(In Thousands, Except Share Information)**

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $ 80 | $ 278 |
| Restricted short-term investments | 65 | 65 |
| Accounts receivable | 110,199 | 93,406 |
| Deferred income taxes | 64,024 | 32,342 |
| Derivative instruments | 2,519 | 2,742 |
| Prepaid expenses and other | 12,371 | 14,033 |
| Total current assets | 189,258 | 142,866 |
| Oil and gas properties (successful efforts basis), buildings and equipment, net | 2,725,567 | 2,655,792 |
| Derivative instruments | 1,562 | 2,054 |
| Other assets | 35,742 | 37,904 |
| | $ 2,952,129 | $ 2,838,616 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable | $ 107,351 | $ 106,459 |
| Revenue and royalties payable | 23,685 | 37,812 |
| Accrued liabilities | 55,100 | 36,234 |
| Line of credit | 13,500 | 5,300 |
| Derivative instruments | 139,721 | 84,846 |
| Total current liabilities | 339,357 | 270,651 |
| Long-term liabilities: | | |
| Deferred income taxes | 322,990 | 329,207 |
| Senior secured revolving credit facility | 205,000 | 170,000 |
| 8.25% Senior subordinated notes due 2016 | 200,000 | 200,000 |
| 10.25% Senior notes due 2014, net of unamortized discount of $10,376 and $11,035, respectively | 439,624 | 438,965 |
| 6.75% Senior notes due 2020 | 300,000 | 300,000 |
| Asset retirement obligation | 55,520 | 53,443 |
| Derivative instruments | 87,035 | 33,526 |
| Other long-term liabilities | 18,231 | 18,271 |
| | 1,628,400 | 1,543,412 |
| Shareholders' equity: | | |
| Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding | — | — |
| Capital stock, $.01 par value: | | |
| Class A Common Stock, 100,000,000 shares authorized; 51,524,080 and 51,426,232 shares issued and outstanding, respectively | 516 | 514 |
| Class B Stock, 3,000,000 shares authorized;1,797,784 shares issued and outstanding (liquidation preference of $899) | 18 | 18 |
| Capital in excess of par value | 334,220 | 327,369 |
| Accumulated other comprehensive loss | (34,283) | (43,806) |
| Retained earnings | 683,901 | 740,458 |
| Total shareholders' equity | 984,372 | 1,024,553 |
| | $ 2,952,129 | $ 2,838,616 |

The accompanying notes are an integral part of these condensed financial statements.

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**BERRY PETROLEUM COMPANY**

**Condensed Statements of Operations**

**(Unaudited)**

**(In Thousands, Except Per Share Data)**

| | Three months ended March 31, 2011 | Three months ended March 31, 2010 |
|---|---|---|
| REVENUES | | |
| Sales of oil and gas | $ 187,389 | $ 147,807 |
| Sales of electricity | 6,412 | 9,933 |
| Gas marketing | 3,685 | 8,272 |
| Interest and other income, net | 128 | 164 |
| | 197,614 | 166,176 |
| EXPENSES | | |
| Operating costs—oil and gas production | 57,083 | 47,036 |
| Operating costs—electricity generation | 6,113 | 9,670 |
| Production taxes | 7,391 | 5,204 |
| Depreciation, depletion & amortization—oil and gas production | 52,109 | 35,907 |
| Depreciation, depletion & amortization—electricity generation | 501 | 795 |
| Gas marketing | 3,516 | 7,786 |
| General and administrative | 16,291 | 13,835 |
| Interest | 15,655 | 17,447 |
| Realized and unrealized loss (gain) on derivatives, net | 127,516 | (1,603) |
| Gain on purchase | (1,046) | (1,358) |
| Transaction costs on acquisitions | — | 2,085 |
| Dry hole, abandonment, impairment and exploration | 113 | 1,369 |
| | 285,242 | 138,173 |
| (Loss) earnings before income taxes | (87,628) | 28,003 |
| Income tax (benefit) provision | (35,131) | 10,334 |
| Net (loss) earnings | $ (52,497) | $ 17,669 |
| Basic net (loss) earnings per share | $ (0.98) | $ 0.34 |
| Diluted net (loss) earnings per share | $ (0.98) | $ 0.34 |
| Dividends per share | $ 0.075 | $ 0.075 |

The accompanying notes are an integral part of these condensed financial statements.

**BERRY PETROLEUM COMPANY**

**Condensed Statements of Cash Flows**

**(Unaudited)**

**(In Thousands)**

| | Three months ended March 31, 2011 | Three months ended March 31, 2010 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net (loss) earnings | $ (52,497) | $ 17,669 |
| Depreciation, depletion and amortization | 52,610 | 36,702 |
| Gain on purchase | (1,046) | (1,358) |
| Amortization of debt issue costs and net discount | 2,099 | 2,098 |
| Dry hole and impairment | — | 1,207 |
| Derivatives | 124,459 | 2,476 |
| Stock-based compensation expense | 3,052 | 3,031 |
| Deferred income taxes | (44,321) | 8,548 |
| Other, net | 679 | — |
| Cash paid for abandonment | (103) | (22) |
| Change in book overdraft | 4,736 | (1,377) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (16,330) | (10,412) |
| Inventories, prepaid expenses, and other current assets | 1,662 | (3,767) |
| Accounts payable and revenue and royalties payable | 6,577 | 3,083 |
| Accrued interest and other accrued liabilities | 18,857 | 5,637 |
| Net cash provided by operating activities | 100,434 | 63,515 |
| Cash flows from investing activities: | | |
| Exploration and development of oil and gas properties | (130,672) | (47,958) |
| Property acquisitions | (2,413) | (132,515) |
| Capitalized interest | (10,392) | (5,967) |
| Deposits on potential property acquisitions | — | (500) |
| Net cash used in investing activities | (143,477) | (186,940) |
| Cash flows from financing activities: | | |
| Proceeds from issuances on line of credit | 124,100 | 76,100 |
| Repayments of borrowings under line of credit | (115,900) | (76,100) |
| Long-term borrowings under credit facility | 63,500 | 125,000 |
| Repayments of long-term borrowings under credit facility | (28,500) | (227,000) |
| Financing obligation | (92) | (83) |
| Debt issuance costs | (4) | — |
| Dividends paid | (4,060) | (4,040) |
| Proceeds from issuance of common stock, net | — | 224,337 |
| Proceeds from stock option exercises | 1,573 | 75 |
| Excess income tax benefit and other | 2,228 | (118) |
| Net cash provided by financing activities | 42,845 | 118,171 |
| Net decrease in cash and cash equivalents | (198) | (5,254) |
| Cash and cash equivalents at beginning of period | 278 | 5,311 |
| Cash and cash equivalents at end of period | $ 80 | $ 57 |
| Noncash investing activities: | | |
| (Decrease) increase in accrued capital expenditures | $ (24,967) | $ 9,513 |
| Increase in asset retirement obligations | 917 | 1,024 |

The accompanying notes are an integral part of these condensed financial statements.

**BERRY PETROLEUM COMPANY**

**Condensed Statement of Shareholders' Equity**

**(Unaudited)**

**(In Thousands, Except Per Share Data)**

| | Class A | Class B | Capital in Excess of Par Value | Retained Earnings | Accumulated Other Comprehensive Loss | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| Balances at December 31, 2010 | $ 514 | $ 18 | $ 327,369 | $ 740,458 | $ (43,806) | $ 1,024,553 |
| Issuance of stock | — | — | — | — | — | — |
| Stock options and restricted stock issued | 2 | — | 1,571 | — | — | 1,573 |
| Stock based compensation | — | — | 3,052 | — | — | 3,052 |
| Income tax effect of stock option exercises | — | — | 2,228 | — | — | 2,228 |
| Dividends ($0.075 per share) | — | — | — | (4,060) | — | (4,060) |
| Comprehensive loss: | | | | | | |
| Net loss | — | — | — | (52,497) | — | (52,497) |
| OCI amortization of de-designated hedges, net of income taxes | — | — | — | — | 9,523 | 9,523 |
| Total comprehensive loss | — | — | — | — | — | (42,974) |
| Balances at March 31, 2011 | $ 516 | $ 18 | $ 334,220 | $ 683,901 | $ (34,283) | $ 984,372 |

The accompanying notes are an integral part of these condensed financial statements.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements**

**(Unaudited)**

**1. Basis of Presentation**

These Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial reporting. All adjustments which are, in the opinion of management, necessary to present fairly Berry Petroleum Company's (the Company) Condensed Financial Statements have been included herein. Interim results are not necessarily indicative of expected annual results because of the impact of fluctuations in prices received for oil and natural gas, as well as other factors. In the course of preparing the Condensed Financial Statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events, and, accordingly, actual results could differ from amounts previously established.

The Company's Condensed Financial Statements have been prepared on a basis consistent with the accounting principles and policies reflected in the Company's audited financial statements as of and for the year ended December 31, 2010. The year-end Condensed Balance Sheet was derived from audited Financial Statements included in such report, but does not include all disclosures required by GAAP.

Certain amounts in the prior year financial statements have been reclassified to conform to the 2011 financial statement presentation. The Company revised Comprehensive (loss) earnings for the three months ended March 31, 2010 from $14.3 million to $21.1 million to reflect the correction of a prior period error. The Company has concluded that the presentation error was immaterial to the previously filed financial statements.

The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at March 31, 2011 and December 31, 2010 are $21.0 million and $16.3 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

**2. Acquisitions**

In March, April and November 2010, the Company completed three separate acquisitions of producing properties located in the Wolfberry trend in the Permian for an aggregate purchase price of approximately $327 million (the Permian Acquisitions). The Permian Acquisitions were financed with net proceeds from the issuance of 8 million shares of the Company's Class A Common Stock in January 2010, cash generated from operations and net proceeds from the issuance of $300 million aggregate principal amount of the Company's 6.75% senior notes due in November 2020.

The Permian Acquisitions qualify as business combinations and, as such, the Company estimated the fair value of each property as of each acquisition date (the date on which the Company obtained control of the properties). The 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. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model based on an income approach and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. Due to the unobservable nature of the inputs, business combinations are deemed to use Level 3 inputs.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

**2. Acquisitions (Continued)**

For the three months ended March 31, 2011, the Company recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments in the first quarter of 2011 to the purchase price of the November 2010 Permian acquisition. The gain was recorded in the Condensed Statements of Operations under the caption Gain on purchase.

The following table summarizes the consideration paid to the sellers and the amounts of the assets acquired and liabilities assumed in the Permian Acquisitions.

| | (In thousands) |
|---|---|
| **Consideration paid to sellers:** | |
| Cash consideration | $ 327,032 |
| **Recognized amounts of identifiable assets acquired and liabilities assumed:** | |
| Proved developed and undeveloped properties | 332,214 |
| Other assets acquired | 342 |
| Asset retirement obligations | (3,498) |
| Deferred income tax liability | (647) |
| Other liabilities assumed | (333) |
| **Total identifiable net assets** | $ 328,078 |

**3. Debt**

***Short-Term Line of Credit***

The Company has an unsecured uncommitted money market line of credit (Line of Credit) with borrowing capacity of up to $40.0 million for a maximum of 30 days. As of March 31, 2011 and December 31, 2010 there were $13.5 million and $5.3 million in outstanding borrowings under the Line of Credit, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The $13.5 million of outstanding borrowings under the Line of Credit at March 31, 2011 had a weighted average interest rate of 1.7%.

***Senior Secured Revolving Credit Facility***

The Company has a senior secured revolving credit facility (Credit Agreement) with a borrowing base and lender commitments of $875 million. As of March 31, 2011 and December 31, 2010 there were $205 million and $170 million in outstanding borrowings under the Credit Agreement, respectively. The Company's total outstanding debt at March 31, 2011 under the Line of Credit and Credit Agreement was $219 million, and $23 million of letters of credit have been issued under the Credit Agreement, leaving $633 million in borrowing capacity available under the Credit Agreement. At March 31, 2011, the LIBOR and prime rate margins are between 1.75% and 2.75% based on the ratio of credit outstanding to the borrowing base, and the annual commitment fee on the unused portion of the Credit Agreement is 0.50%.

The maximum amount available is subject to semi-annual redeterminations of the borrowing base based on the value of the Company's proved oil and natural gas reserves in April and October of each year in accordance with the lenders' customary procedures and practices. The Company and the banks

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**3. Debt (Continued)**

each have the unilateral right to one additional redetermination each year. The Credit Agreement is collateralized by the Company's oil and natural gas properties.

The Credit Agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. The Credit Agreement contains restrictive covenants which, among other things, require the Company to maintain the following ratios: (i) an interest coverage ratio, as defined, of 2.75 to 1.0 and (ii) a minimum current ratio, as defined in the Credit Agreement, of 1.0 to 1.0. The Company is currently in compliance with all financial covenants and has complied with all financial covenants for all prior periods.

On April 13, 2011, the Company entered into a First Amendment (Amendment) to its Credit Agreement. See Note 12 to the Condensed Financial Statements.

**4. Income Taxes**

The effective income tax rates for the three months ended March 31, 2011 and 2010 were 40.1% and 36.9%, respectively. The increase in rate in the first quarter of 2011 as compared to the first quarter of 2010 is primarily due to a one-time reduction in deferred state taxes as a result of acquisitions in more tax favorable jurisdictions, reducing future state tax obligations. This benefit increased the effective tax rate due to the Company's reported loss in the first quarter of 2011. The Company's estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

As of March 31, 2011, the Company had a gross liability for uncertain tax benefits of $5.3 million, which if recognized would affect the effective tax rate. There were no significant changes to the calculation subsequent to December 31, 2010. The Company recognized potential accrued interest and penalties related to unrecognized tax benefits in income tax expense during the first quarter of 2011, which is consistent with the recognition of these items in prior periods.

The Company has accrued approximately $0.8 million of interest related to its uncertain tax positions as of March 31, 2011 and December 31, 2010. The Company estimates that it is reasonably possible that the balance of unrecognized tax benefits as of March 31, 2011 could decrease by a maximum of $1.9 million in the next 12 months due to the expiration of statutes of limitations and audit settlements.

**5. Earnings (Loss) Per Share and Comprehensive (Loss) Earnings**

Basic (loss) earnings per share is calculated by dividing adjusted (loss) earnings available to common shareholders by the weighted average shares outstanding-basic during each period. Diluted (loss) earnings per common share is calculated by dividing (loss) earnings available to common shareholders by the weighted average shares outstanding-dilutive, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted (loss) earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted (loss) earnings per share.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**5. Earnings (Loss) Per Share and Comprehensive (Loss) Earnings (Continued)**

The two-class method of computing (loss) earnings per share is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Restricted stock issued prior to January 1, 2010 under the Company's equity incentive plans has the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Restricted stock issued subsequent to January 1, 2010 under the Company's equity incentive plans no longer has the right to receive non-forfeitable dividends. Stock options issued under the Company's equity incentive plans do not participate in dividends.

The following table shows the computation of basic and diluted (loss) earnings per share for the three months ended March 31, 2011 and 2010:

| (in thousands, except per share data) | Three months ended March 31, 2011 | 2010 |
|---|---|---|
| Net (loss) earnings | $ (52,497) | $ 17,669 |
| Less: earnings allocable to participating securities | — | 359 |
| (Loss) earnings available for shareholders | $ (52,497) | $ 17,310 |
| Basic (loss) earnings per share | $ (0.98) | $ 0.34 |
| Diluted (loss) earnings per share | $ (0.98) | $ 0.34 |
| Weighted average shares outstanding—basic | 53,866 | 51,076 |
| Add: Dilutive effects of stock options and RSUs | — | 365 |
| Weighted average shares outstanding—dilutive | 53,866 | 51,441 |

Options to purchase 1.9 million shares and 1.2 million shares were not included in the diluted (loss) earnings per share calculation for the three months ended March 31, 2011 and 2010, respectively, because their effect would have been anti-dilutive.

***Comprehensive (loss) earnings***

Comprehensive (loss) earnings is a term used to refer to net (loss) earnings plus other comprehensive (loss) earnings. Other comprehensive (loss) earnings is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of shareholders' equity instead of net (loss) earnings. The components of other comprehensive (loss) earnings were as follows:

| (in thousands) | Three months ended March 31, 2011 | 2010 |
|---|---|---|
| Net (loss) earnings | $ (52,497) | $ 17,669 |
| Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $5,836 and $2,084, respectively | 9,523 | 3,400 |
| Comprehensive (loss) earnings | $ (42,974) | $ 21,069 |

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**6. Asset Retirement Obligation**

The following table summarizes the activity for the Company's asset retirement obligations (ARO) for the three months ended March 31, 2011 and 2010:

| (in thousands) | Three months ended March 31, 2011 | Three months ended March 31, 2010 |
|---|---|---|
| Beginning balance at January 1 | $ 53,443 | $ 43,487 |
| Liabilities incurred | 917 | 1,024 |
| Liabilities settled | (103) | (22) |
| Liabilities assumed | — | — |
| Acquisition of assets | — | 1,367 |
| Accretion expense | 1,263 | 1,063 |
| Ending balance at March 31 | $ 55,520 | $ 46,919 |

The ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and gas properties. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

**7. Equity Incentive Compensation Plans**

Stock-based compensation is measured at the grant date based on the value of the awards, and the fair value is recognized on a straight-line basis over the requisite service period (usually the vesting period).

Total compensation cost recognized in the Statements of Operations for the grants under the Company's equity incentive compensation plans was $2.9 million and $2.3 million during the three months ended March 31, 2011 and 2010, respectively.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**7. Equity Incentive Compensation Plans (Continued)**

***Stock Options***

The following table summarizes stock option activity in the Company's equity incentive compensation plans for the three months ended March 31, 2011.

| | Number of Shares | Weighted Average Exercise Price | Aggregate Intrinsic Value (in thousands)(1) | Number of Shares Exercisable |
|---|---|---|---|---|
| Outstanding at January 1, 2011 | 2,017,225 | $ 25.87 | $ 35,974 | 1,884,937 |
| Granted | 89,865 | 48.50 | | |
| Exercised | (117,850) | 14.43 | | |
| Cancelled/expired | — | — | | |
| Outstanding at March 31, 2011 | 1,989,240 | $ 27.57 | $ 45,520 | 1,767,837 |

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the end of the related period exceeds the exercise price of the option.

In March 2011, 89,865 stock options were granted under the 2010 Equity Incentive Plan to certain executive officers and other officers of the Company with exercise prices equal to the closing market price of the Company's Class A Common Stock on the grant date. These stock options vest ratably over a four-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The fair value of each option granted was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of options granted:

| | 2011 |
|---|---|
| Expected volatility | 45.0% |
| Risk-free interest rate | 2.54% |
| Dividend yield | 0.62% |
| Expected term (in years) | 6.0 |

As of March 31, 2011, there was $2.0 million of total unrecognized compensation cost related to stock options granted. This cost is expected to be recognized over 4 years.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**7. Equity Incentive Compensation Plans (Continued)**

***Restricted Stock Units***

The following table summarizes the restricted stock unit (RSU) activity in the Company's stock-based compensation plans for the three months ended March 31, 2011.

| | RSUs | Weighted Average Grant Date Fair-Value | Vest Date Fair Value (in thousands) |
|---|---|---|---|
| Outstanding at January 1, 2011 | 857,360 | $ 19.67 | |
| Granted | 150,741 | 47.77 | |
| Issued | (11,348) | 36.60 | $ 522 |
| Canceled/expired | (688) | 27.65 | |
| Outstanding at March 31, 2011(1)(2) | 996,065 | $ 23.72 | |

(1) The balance outstanding includes 30,544 RSUs granted to the non-employee Directors that are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued.

(2) The balance outstanding includes 294,767 RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement, but are subject to a deferral election before the corresponding shares are issued.

As of March 31, 2011, there was $11.5 million of total unrecognized compensation cost related to RSUs granted. This cost is expected to be recognized over 4 years.

***Performance Share Program***

The following table summarizes the performance share awards activity in the Company's stock-based compensation plans for the three months ended March 31, 2011.

| | Performance Share Awards | Weighted Average Grant Date Fair-Value | Vest Date Fair Value (in Thousands) |
|---|---|---|---|
| Outstanding at January 1, 2011 | 103,794 | $ 31.20 | |
| Granted | 65,620 | 51.86 | |
| Issued | — | — | $ — |
| Canceled/expired | — | — | |
| Outstanding at March 31, 2011 | 169,414 | $ 39.20 | |

In March 2011, 65,620 performance share awards, which are subject to internal performance metrics and market based vesting criteria in addition to a three-year service condition, were granted to executive officers and other officers. The ultimate vesting of awards is contingent upon meeting the established criteria. From January 1, 2011 to December 31, 2013, the Company must maintain an interest coverage ratio of at least 2.5 to 1.0. The number of performance share awards that ultimately vest is based on two equally weighted performance factors: (i) compounded annual production growth

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**7. Equity Incentive Compensation Plans (Continued)**

as measured by average annual barrels of oil equivalent per day (BOE/D) and (ii) total shareholder return as compared to the Company's defined peer group for years 2011-2013.

For the portion of performance share awards subject to internal performance metrics, the grant date fair value was determined by reference to the closing price of a share of Class A Common Stock on the date of grant. The Company recognizes compensation expense when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

For the portion of performance share awards subject to market based vesting criteria, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based restricted shares were as follows:

| | 2011 |
|---|---|
| Number of simulations | 100,000 |
| Expected volatility | 44% |
| Risk-free rate | 1.15% |

As of March 31, 2011, there was $2.6 million of total unrecognized compensation cost related to performance share awards granted. This cost is expected to be recognized over 2.8 years.

**8. Derivative Instruments**

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. The Company has entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. The terms of the contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and future financial commitments. The Company periodically enters into interest rate derivative agreements to protect against changes in interest rates. For further discussion related to the fair value of the Company's derivatives see Note 9 to the Condensed Financial Statements.

As of March 31, 2011, the Company had commodity derivatives associated with the following volumes:

| | 2011 | 2012 | 2013 |
|---|---|---|---|
| Oil Bbl/D: | 19,020 | 17,000 | 11,000 |
| Natural Gas MMBtu/D: | 15,000 | 15,000 | — |

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**8. Derivative Instruments (Continued)**

The Company entered into the following crude oil three-way collars during the three months ended March 31, 2011:

| Term | Average Barrels Per Day | Floor/Swap/Ceiling Prices |
|---|---|---|
| February 2011 - December 2013 | 1,000 | $70.00 / $90.00 / $116.50 |
| Full year 2012 and 2013 | 1,000 | $70.00 / $90.00 / $120.00 |
| Full year 2012 and 2013 | 1,000 | $70.00 / $95.00 / $120.10 |

***Discontinuance of cash flow hedge accounting***

Effective January 1, 2010, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL.

At December 31, 2010, AOCL consisted of $70.7 million ($43.8 million, net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges.

At March 31, 2011, AOCL consisted of $55.3 million ($34.3 million net of income tax) of unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. During the three months ended March 31, 2011, $15.4 million ($9.5 million, net of income tax) of amortization of AOCL relating to de-designated commodity and interest rate hedges was reclassified from AOCL into earnings. The Company expects to reclassify into earnings from AOCL after-tax net losses of $30.0 million related to de-designated commodity and interest rate derivative contracts during the next 12 months.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**8. Derivative Instruments (Continued)**

The following tables detail the fair value of derivatives recorded on the Company's Condensed Balance Sheets, by category:

| | March 31, 2011 | | | |
|---|---|---|---|---|
| | Derivative Assets | | Derivative Liabilities | |
| (in millions) | Balance Sheet Classification | Fair Value | Balance Sheet Classification | Fair Value |
| Current: | | | | |
| Commodity | Derivative assets | $ 2.5 | Derivative liabilities | $ 139.7 |
| Long term: | | | | |
| Commodity | Derivative assets | 1.6 | Derivative liabilities | 87.0 |
| Total derivatives | | $ 4.1 | | $ 226.7 |

| | December 31, 2010 | | | |
|---|---|---|---|---|
| | Derivative Assets | | Derivative Liabilities | |
| (in millions) | Balance Sheet Classification | Fair Value | Balance Sheet Classification | Fair Value |
| Current: | | | | |
| Commodity | Derivative assets | $ 2.7 | Derivative liabilities | $ 84.9 |
| Long term: | | | | |
| Commodity | Derivative assets | 2.1 | Derivative liabilities | 33.5 |
| Total derivatives | | $ 4.8 | | $ 118.4 |

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**8. Derivative Instruments (Continued)**

The table below summarizes the location and the amount of derivative instrument gains (losses) before income taxes reported in the Condensed Statements of Operations for the periods indicated (in millions):

| Description of (Loss) Gain | Location of (Loss) Gain Recognized in Earnings | Three months ended March 31, 2011 | Three months ended March 31, 2010 |
|---|---|---|---|
| **Commodity** | | | |
| (Loss) gain reclassified from AOCL into earnings (amortization of frozen amounts) | Sales of oil and gas | $ (14.6) | $ (2.8) |
| (Loss) gain recognized in earnings (cash settlements and mark-to-market movements) | Realized and unrealized loss (gain) on derivatives, net | (127.5) | 4.9 |
| **Interest rate** | | | |
| (Loss) gain reclassified from AOCL into earnings (amortization of frozen amounts) | Interest | $ (0.8) | $ (2.7) |
| (Loss) gain recognized in earnings (cash settlements and mark-to-market movements) | Realized and unrealized loss (gain) on derivatives, net | — | (3.3) |

***Credit risk***

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at March 31, 2011 was $4.1 million.

As of March 31, 2011, the counterparties to the Company's commodity derivative contracts consist of nine financial institutions. The Company's counterparties or their affiliates are generally also lenders under the Company's Credit Agreement. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's Credit Agreement. The Company is not generally required to post additional collateral under derivative agreements.

Certain of the Company's derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company was to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time. As of March 31, 2011, the Company was in a net liability position with eight of the counterparties to the Company's derivative instruments, totaling $227 million. As of March 31, 2011, the Company's largest three counterparties accounted for 55% of the value of its total net derivative positions.

## 9. Fair Value Measurements

The authoritative guidance for fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument's categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. The fair value of all derivative instruments is estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value of all derivative instruments is estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The pricing services publish observable market information from multiple brokers and exchanges. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

***Liabilities measured at fair value on a recurring basis***

The following tables set forth by level within the fair value hierarchy the Company's net derivative liabilities that were measured at fair value on a recurring basis as of March 31, 2011 and December 31, 2010.

| (in millions) | Total | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| Commodity derivatives liability, net | | | | |
| March 31, 2011 | $ (222.6) | $ — | $ (222.6) | $ — |
| December 31, 2010 | $ (113.6) | $ — | $ (11.8) | $ (101.8) |

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**9. Fair Value Measurements (Continued)**

***Changes in Level 3 fair value measurements***

The table below includes a rollforward of the Condensed Balance Sheet amounts (including the change in fair value) for financial instruments classified by the Company within Level 3 of the fair value hierarchy. When a determination is made to classify a financial instrument within Level 3 of the fair value hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

| (in millions) | Three months ended March 31, 2011 | Three months ended March 31, 2010 |
|---|---|---|
| Fair value liability, beginning of period | $ (101.8) | $ (26.0) |
| Transfers out of Level 3(1) | 101.8 | — |
| Realized and unrealized gain included in earnings | | 0.7 |
| Settlements | | (9.2) |
| Fair value liability, end of period | $ — | $ (34.5) |
| Total unrealized (loss) gain included in earnings related to financial assets and liabilities still on the Condensed Balance Sheet at March 31, 2011 and 2010 | $ — | $ (8.4) |

(1) During the first quarter of 2011, the inputs used to value oil collars, natural gas collars and natural gas basis swaps were directly or indirectly observable, and these instruments were transferred to level 2.

For further discussion related to the Company's derivatives see Note 8 to the Condensed Financial Statements.

## 9. Fair Value Measurements (Continued)

### *Fair Market Value of Financial Instruments*

The Company uses various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company's credit facilities approximated fair value because the interest rates on the credit facilities are variable and could be at similar rates today. The fair values of the 8.25% senior subordinated notes due 2016, the 10.25% senior notes due 2014, and the 6.75% senior notes due 2020 were estimated based on quoted market prices. The fair values of the Company's derivative instruments and other investments are discussed above.

| | March 31, 2011 | | December 31, 2010 | |
|---|---|---|---|---|
| (in millions) | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| Line of credit | $ 14 | $ 14 | $ 5 | $ 5 |
| Senior secured revolving credit facility | 205 | 205 | 170 | 170 |
| 8.25% Senior subordinated notes due 2016 | 200 | 211 | 200 | 210 |
| 10.25% Senior notes due 2014 | 440 | 523 | 439 | 518 |
| 6.75% Senior notes due 2020 | 300 | 311 | 300 | 303 |
| | $ 1,159 | $ 1,264 | $ 1,114 | $ 1,206 |

## 10. Dry hole, abandonment, impairment and exploration

For the three months ended March 31, 2011, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.1 million. During the three months ended March 31, 2010, the Company incurred dry hole, abandonment, impairment and exploration expense of $1.4 million, which was primarily the result of mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same pad.

## 11. Commitments and Contingencies

### *Uinta Crude Oil Sales Contract*

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from the Company's Uinta properties averaged approximately 3,500 Bbl/D in the first quarter of 2011. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the Company's crude oil sales customer in Utah could impact the marketability of a portion of the Company's Utah crude oil volumes.

See Item 1A. Risk Factors of the Company's Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on March 1, 2011.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**11. Commitments and Contingencies (Continued)**

***E. Texas Gathering System***

In July 2009, the Company closed on the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. The transaction was treated as a financing obligation. Accordingly, the $16.7 million net book value of the property is being depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of payments under the agreements are recorded as gathering expense and a portion as interest expense, with the balance being recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements. For the three months ended March 31, 2011 and 2010, the Company incurred $1.7 million and $1.0 million, respectively, under the agreements.

***Carry and Earning Agreement***

On January 14, 2011, the Company entered into an amendment relating to certain contractual obligations to a third party co-owner of certain Piceance assets in Colorado. The amendment waives the $0.2 million penalty for each well not spud by February 2011. The Company is obligated to pay the first $4.5 million of costs incurred by such third party in connection with the construction, on behalf of both the Company and such third party, of either an extension of an existing access road or a new access road. If by December 31, 2012 (which date may, under certain circumstances, be extended until December 31, 2014), the Company has not expended $9.0 million ($4.5 million of which would otherwise be such third party's responsibility) in road construction costs, then it will be obligated to pay the third party 50% of the difference between $12.0 million and the actual amount expended on road construction as of such date. In addition, the amendment extends the date by which the Company must complete its drilling obligations on the North Parachute property to January 31, 2020.

***Legal Matters***

**BLM Settlement.** On March 28, 2011, the Company entered into a settlement agreement with the Bureau of Land Management (BLM) resolving all claims by the BLM that the Company did not comply with BLM regulations relating to the operation and position of certain valves, and the submission of related site facility diagrams, in its Uinta operations. The settlement agreement confirmed that the Company promptly remediated the alleged noncompliance upon learning of it, and cooperated with the BLM's investigation, and that there is no evidence of any senior Company management knowledge of the alleged noncompliance, or of any environmental harm or loss of oil or royalty revenue resulting from such alleged noncompliance. On April 15, 2011, the Company paid a $2.1 million civil penalty to the BLM under the settlement agreement.

**Royalty Payments.** Certain of the Company's royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that the Company may be required to pay are up to approximately $7 million.

**BERRY PETROLEUM COMPANY**

**Notes to Condensed Financial Statements (Continued)**

**(Unaudited)**

**11. Commitments and Contingencies (Continued)**

**Other.** The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, results of operations or operating cash flows.

***Environmental Matters***

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred.

**12. Subsequent Events**

***Amendment to Credit Agreement***

On April 13, 2011, the Company entered into an Amendment to its Credit Agreement. The Amendment extended the maturity date of the Credit Agreement to May 13, 2016 and increased the borrowing base from $875 million to $1.4 billion. Lender commitments remain unchanged at $875 million. In addition, the Amendment reduced (i) the LIBOR margin to between 1.50% and 2.50% based on the ratio of credit outstanding to the borrowing base, (ii) the prime rate margin to between 0.50% and 1.50% based on the ratio of credit outstanding to the borrowing base, and (iii) the annual commitment fee on the unused portion of the Credit Agreement to between 0.35% and 0.50%. The Amendment also provides the right for the Company to refinance its 10.25% senior notes due in 2014 ("2014 Notes") and its 8.25% senior subordinated Notes ("2016 Notes") with similar notes or retire the 2014 Notes or the 2016 Notes using available borrowing under the Credit Agreement as long as certain leverage and liquidity tests are met.

***Permian Acquisition***

On April 13, 2011, the Company entered into an agreement to acquire the interests in properties on approximately 6,000 net acres in the Wolfberry trend in the Permian for approximately $123 million in cash, subject to usual and customary post-closing adjustments.

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

The following is management's discussion and analysis of certain significant factors that have affected aspects of our financial position and the results of operations during the periods included in the accompanying Condensed Financial Statements. You should read this in conjunction with the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Financial Statements for the year ended December 31, 2010, included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition, exploration and fair value of our derivative instruments. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by global supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. We benefit from lower natural gas prices as we are a consumer of natural gas in our California operations. In the Rocky Mountains and E. Texas, we benefit from higher natural gas pricing. The cost of natural gas used in our steaming operations and electrical generation, production rates, labor, equipment costs, maintenance expenses, and production taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

**Notable First Quarter 2011 Items**

- Generated discretionary cash flow of $85 million from production of 34,405 BOE/D and operating margin of $38.18 per BOE (1)
- Increased Permian production by 35% from the fourth quarter of 2010 through execution of our four rig drilling program
- Drilled 76 Diatomite production wells and reestablished continuous operations
- Based on market conditions, sold our California heavy oil at a $5 premium to WTI beginning in March 2011

**Notable Items and Expectations for the Second Quarter and Full Year 2011**

- Anticipating full approval by the California Division of Oil, Gas and Geothermal Resources (DOGGR) in the second quarter of 2011 for full Diatomite project development
- Expecting Diatomite production to increase to 5,000 BOE/D by mid-2011
- Acquiring interests in producing properties on approximately 6,000 net acres in the Wolfberry trend for $123 million
- Increased our borrowing base from $875 million to $1.4 billion in April 2011
- As a result of acquisition activity, we are increasing 2011 development capital to be between $400 million and $450 million, increasing our expected 2011 average production to be between 37,500 BOE/D and 39,500 BOE/D

***Results of Operations.***

In the first quarter of 2011, we reported a net loss of $52.5 million, or $0.98 per diluted share, and net cash flows from operations of $100 million. The net loss includes a $74.6 million loss on derivatives, as a result of non-cash changes in fair values and amortization of frozen fair values.

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(1) Discretionary cash flow and operating margin are considered non-GAAP performance measures and reference should be made to *"Reconciliation of Non-GAAP Measures"* in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for further explanation as well as reconciliations to the most directly comparable GAAP measures.

***Operating Data.***

The following table sets forth selected operating data for the three months ended:

| | March 31, 2011 | % | March 31, 2010 | % | December 31, 2010 | % |
|---|---|---|---|---|---|---|
| Heavy oil production (BOE/D) | 16,226 | 47 | 17,752 | 61 | 16,548 | 48 |
| Light oil production (BOE/D) | 6,422 | 19 | 2,754 | 9 | 6,131 | 18 |
| Total oil production (BOE/D) | 22,648 | 66 | 20,506 | 70 | 22,679 | 66 |
| Natural gas production (Mcf/D) | 70,542 | 34 | 53,309 | 30 | 70,828 | 34 |
| Total (BOE/D) | 34,405 | 100 | 29,391 | 100 | 34,484 | 100 |
| Oil and gas, per BOE: | | | | | | |
| Average realized sales price | $ 60.26 | | $ 55.99 | | $ 53.55 | |
| Average sales price including cash derivative settlements | 59.01 | | 57.09 | | 53.75 | |
| Oil, per Bbl: | | | | | | |
| Average WTI price | $ 94.60 | | $ 78.88 | | $ 85.20 | |
| Price sensitive royalties (a) | (3.56) | | (3.04) | | (3.37) | |
| Quality differential and other (b) | (5.68) | | (8.12) | | (9.16) | |
| Crude oil derivatives non-cash amortization (c) | (7.07) | | (1.72) | | (3.22) | |
| Oil revenue | $ 78.29 | | $ 66.00 | | $ 69.45 | |
| Add: Crude oil derivatives non cash amortization (c) | 7.07 | | 1.72 | | 3.22 | |
| Crude oil derivative cash settlements (d) | (10.24) | | (0.22) | | (4.35) | |
| Average realized oil price | $ 75.12 | | $ 67.50 | | $ 68.32 | |
| Natural gas price: | | | | | | |
| Average Henry Hub price per MMBtu | $ 4.11 | | $ 5.30 | | $ 3.80 | |
| Conversion to Mcf | 0.21 | | 0.27 | | 0.19 | |
| Natural gas derivatives non cash amortization (c) | (0.01) | | 0.07 | | 0.05 | |
| Location, quality differentials and other | (0.09) | | (0.15) | | (0.14) | |
| Natural gas revenue per Mcf | $ 4.22 | | $ 5.49 | | $ 3.90 | |
| Add: Natural gas derivatives non cash amortization (c) | 0.01 | | (0.07) | | (0.05) | |
| Natural gas derivative cash settlements (d) | 0.41 | | 0.11 | | 0.50 | |
| Average realized natural gas price per Mcf | $ 4.64 | | $ 5.53 | | $ 4.35 | |

(a) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of heavy oil posted price above a base price which was $17.09 per barrel during the first quarter of 2011 as long as we maintain a minimum steam injection level. We met the steam injection level in the first quarter of 2011, and expect to meet the requirement going forward. The base price escalates at 2% annually and it will be $17.43 in 2012.

(b) In California, the differential at March 31, 2011 was $5.13 and ranged from a low of $(6.43) to a high of $5.14 per barrel during the first quarter of 2011, based on all postings. In Utah, the differential during the first quarter of 2011 and at March 31, 2011 was $15, based on all postings.

(c) Non-cash amortization of frozen December 31, 2009 fair values, resulting from discontinuing hedge accounting as of January 1, 2010, recorded in Sales of oil and gas.

(d) Cash settlements on derivatives recorded in Realized and unrealized loss (gain) on derivatives, net.

The following results are in millions (except per share data) for the three month periods ended:

| | March 31, 2011 (1Q11) | March 31, 2010 (1Q10) | 1Q10 to 1Q11 Change | December 31, 2010 (4Q10) | 4Q10 to 1Q11 Change |
|---|---|---|---|---|---|
| Sales of oil | $ 160 | $ 122 | 31% | $ 143 | 12% |
| Sales of gas | 27 | 26 | 4% | 25 | 8% |
| Total sales of oil and gas | $ 187 | $ 148 | 26% | $ 168 | 11% |
| Sales of electricity | 7 | 10 | (30)% | 8 | (13)% |
| Gas marketing | 4 | 8 | (50)% | 4 | — |
| Interest and other income, net | — | — | — | 1 | — |
| Total revenues and other income | $ 198 | $ 166 | 19% | $ 181 | 9% |
| Net (loss) earnings | $ (52) | $ 18 | — | $ (21) | — |
| Diluted (loss) earnings per share | $ (0.98) | $ 0.34 | — | $ (0.40) | — |

***Sales of Oil and Gas.***

Sales of oil and gas increased $39 million, or 26%, to $187 million in first quarter of 2011 compared to $148 million in the first quarter of 2010. The increase is due primarily to a 17% increase in sales volumes and an increase in the average sales price to $60.26 per BOE in the first quarter of 2011 from $55.99 per BOE in the first quarter of 2010. Sales of oil and gas for the first quarter of 2011 and 2010 include non-cash derivative losses $7.07 per BOE and $1.72 per BOE, respectively. Sales of oil and gas in the first quarter of 2011 increased $19 million, or 11%, to $187 million in the first quarter of 2011 compared to $168 million in the fourth quarter of 2010. The increase is due primarily to a 13% increase in the average sales price to $60.26 per BOE in the first quarter of 2011 from $53.55 in the fourth quarter of 2010. Sales of oil and gas for the first quarter of 2011 and the fourth quarter of 2010 include non-cash derivative losses of $7.07 per BOE and $3.22 per BOE, respectively.

Approximately 66% of our oil and gas sales volumes in the first quarter of 2011 were crude oil, with 72% of the crude oil being heavy oil produced in California, which was sold under various contracts with prices tied to the San Joaquin posted price.

***Sales of Electricity.***

Sales of electricity decreased in the first quarter of 2011 compared to the first quarter of 2010 due to a 15% decrease in electric power sold due to the shut down of one of our three cogeneration facilities for maintenance during March 2011. Additionally, the average sales price decreased 25% in the first quarter of 2011 as compared to the first quarter of 2010. Electricity operating costs decreased in the first quarter of 2011 compared to the first quarter of 2010 due to a 14% decrease in electric power produced and a 20% decrease in fuel gas cost. Sales of electricity decreased 14% in the first quarter of 2011 compared to the fourth quarter of 2010 primarily due to a 13% decrease in electric power sold related to the cogeneration facility shut down for maintenance in March 2011. We purchased approximately 23,000, 28,000 and 27,000 MMBtu/D of natural gas as fuel for use in our cogeneration facilities for the three months ended March 31, 2011, March 31, 2010 and December 31, 2010, respectively.

| | Three months ended | | |
|---|---|---|---|
| | March 31, 2011 | March 31, 2010 | December 31, 2010 |
| **Electricity** | | | |
| Revenues (in millions) | $ 6.4 | $ 9.9 | $ 7.4 |
| Operating costs (in millions) | $ 6.1 | $ 9.7 | $ 6.6 |
| Electric power produced—MWh/D | 1,856 | 2,154 | 2,110 |
| Electric power sold—MWh/D | 1,689 | 1,979 | 1,948 |
| Average sales price/MWh | $ 42.17 | $ 56.17 | $ 40.99 |
| Fuel gas cost/MMBtu (including transportation) | $ 4.33 | $ 5.39 | $ 4.01 |

***Natural Gas Marketing.***

We have long-term firm transportation contracts on the Rockies Express pipeline for our Piceance natural gas production, with total capacity of 35,000 MMBtu/D. We pay a demand charge for this capacity; however, at the present time our own production is insufficient to fully utilize this capacity. In order to maximize the value of this transportation, we purchased our partners' working interest share of the gas produced at the market rate for the producing area and entered into FERC-approved Asset Management Agreements with our marketers whereby they fill any remaining unused capacity. The Rockies Express pipeline moves the gas to a location near Lebanon, Ohio where we received a price based on that sales point. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Operations for the three months ended March 31, 2011 and 2010 is $0.2 million and $0.5 million, respectively.

Firm transportation costs related to all of our Rockies Express pipeline volumes are reflected in Operating costs—oil and gas production and total $4.0 million and $3.2 million for the three months ended March 31, 2011 and 2010, respectively.

***Oil and Gas Operating and Other Expenses.***

The following table presents information about our operating expenses for each of the three month periods ended:

| | Amount per BOE | | | Amount (in thousands) | | |
|---|---|---|---|---|---|---|
| | March 31, 2011 | March 31, 2010 | December 31, 2010 | March 31, 2011 | March 31, 2010 | December 31, 2010 |
| Operating costs—oil and gas production | $ 18.44 | $ 17.78 | $ 15.74 | $ 57,083 | $ 47,036 | $ 49,949 |
| Production taxes | 2.39 | 1.97 | 2.05 | 7,391 | 5,204 | 6,516 |
| DD&A—oil and gas production | 16.83 | 13.57 | 15.90 | 52,109 | 35,907 | 50,456 |
| General and administrative | 5.26 | 5.23 | 4.56 | 16,291 | 13,835 | 14,457 |
| Interest expense | 5.06 | 6.60 | 5.41 | 15,655 | 17,447 | 17,168 |
| Total | $ 47.98 | $ 45.15 | $ 43.66 | $ 148,529 | $ 119,429 | $ 138,546 |

- Operating costs in the first quarter of 2011 were $57.1 million, or $18.44 per BOE, compared to $47.0 million or $17.78 per BOE in the first quarter of 2010 and $49.9 million, or $15.74 per BOE, in the fourth quarter of 2010. The increase in operating costs per BOE in the first quarter of 2011 compared to the first quarter of 2010 is primarily due to a proposed legal settlement accrual of $1.3 million, higher expenditures for well workovers offset by a decrease in steam costs. The increase in operating costs per BOE in the first quarter of 2011 compared to the fourth quarter of 2010 is primarily due to higher steam costs resulting from higher fuel cost/MMBtu offset by lower volumes of injected steam, an accrual of $1.3 million related to a proposed legal settlement and higher expenditures for well workovers.

The following table presents steam information for the three months ended:

| | March 31, 2011 (1Q11) | March 31, 2010 (1Q10) | 1Q10 to 1Q11 Change | December 31, 2010 (4Q10) | 4Q10 to 1Q11 Change |
|---|---|---|---|---|---|
| Average volume of steam injected (Bbl/D) | 120,612 | 118,733 | 2% | 121,037 | — |
| Fuel gas cost/MMBtu (including transportation) | $ 4.33 | $ 5.39 | (20)% | $ 4.01 | 8% |
| Approximate net fuel gas volume consumed in steam generation (MMBtu/D) | 39,552 | 36,699 | 8% | 39,592 | — |

- Production taxes in the first quarter of 2011 were $7.4 million, or $2.39 per BOE, compared to $5.2 million, or $1.97 per BOE, in the first quarter of 2010 and $6.5 million or $2.05 per BOE in the fourth quarter of 2010. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the production tax rate in effect for those areas. The increase in production taxes, on a per BOE basis, compared to the first quarter of 2010 and fourth quarter of 2010 was primarily due to an increase in the assessed ad valorem values attributed to our California properties. In addition, our Permian and Utah properties contributed to a higher cost per BOE due to severance taxes being tied to field sales prices.

- Depreciation, depletion and amortization (DD&A) related to oil and gas production in the first quarter of 2011 was $52.1 million, or $16.83 per BOE, compared to $35.9 million, or $13.57 per BOE, in the first quarter of 2010 and $50.5 million, or $15.90 per BOE, in the fourth quarter of 2010. The increase in DD&A in the first quarter of 2011 compared to both the first quarter of 2010 and the fourth quarter of 2010 was primarily due to the contribution of our development properties with higher drilling and leasehold acquisition costs than our California properties, including our recent acquisitions in the Permian and a shift in production volumes to assets outside of California.

- General and administrative expense (G&A) in the first quarter of 2011 was $16.3 million, or $5.26 per BOE, compared to $13.8 million, or $5.23 per BOE, in the first quarter of 2010 and $14.5 million, or $4.56 per BOE in the fourth quarter of 2010. G&A increased compared to the first quarter of 2010 due to an increase in benefit costs, including bonus cost resulting from personnel hired during the past twelve months and general pay increases. G&A increased compared to the fourth quarter of 2010 due to director compensation of $1.2 million recorded in the first quarter of 2011.

- Interest expense in the first quarter of 2011 was $15.7 million, or $5.06 per BOE, compared to $17.4 million, or $6.60 per BOE, in the first quarter of 2010 and $17.2 million, or $5.41 per BOE, in the fourth quarter of 2010. The decrease in interest expense in the first quarter of 2011 compared to the first quarter of 2010 was due to an increase in capitalized interest related to recent Permian acquisitions, a reduction of the amount outstanding under our Credit Agreement and an additional $1.9 million of non-cash derivative losses related to de-designated interest rate hedges reclassified from AOCL. These decreases were offset by the addition of the $300 million aggregate principal amount of our 6.75% senior notes due 2020. The decrease in interest expense in the first quarter of 2011 compared to the fourth quarter of 2010 was primarily due to an increase in capitalized interest.

***Realized and unrealized loss (gain) on derivatives, net.***

Realized and unrealized loss (gain) on derivatives, net includes the realized gains and losses (cash settlements) and unrealized gains and losses (non-cash changes in fair value) of our derivative instruments. Effective January 1, 2010, we elected to de-designate all of our commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2010 derivative contract fair value gains and losses are recognized immediately in earnings. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings under the caption Realized and unrealized loss (gain) on derivatives, net. See Notes 8 and 9 to the Condensed Financial Statements for more information on our derivative instruments.

The following table sets forth the cash settlements and non-cash mark-to-market adjustments for the derivative contracts recorded in Realized and unrealized loss (gain) on derivatives, net for the periods indicated:

| | Three months ended | | |
|---|---|---|---|
| **(in thousands)** | **March 31, 2011** | **March 31, 2010** | **December 31, 2010** |
| Cash (receipts) payments: | | | |
| Commodity derivatives—oil | $ 21,009 | $ 414 | $ 8,973 |
| Commodity derivatives—natural gas | (2,592) | (517) | (3,272) |
| Financial derivatives—interest | — | 1,826 | 12,033 |
| Total cash (receipts) payments | $ 18,417 | $ 1,723 | $ 17,734 |
| Mark-to-market loss (gain): | | | |
| Commodity derivatives—oil | $ 107,089 | $ 7,112 | $ 52,676 |
| Commodity derivatives—natural gas | 2,010 | (11,939) | 3,748 |
| Financial derivatives—interest(1) | — | 1,501 | (11,828) |
| Total mark-to-market loss (gain) | $ 109,099 | $ (3,326) | $ 44,596 |
| Total realized and unrealized loss (gain) on derivatives, net | $ 127,516 | $ (1,603) | $ 62,330 |

(1) In the fourth quarter of 2010, we terminated certain interest rate derivative instruments. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million.

***Gain on purchase.*** For the three months ended March 31, 2011, we recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments during the three months ended March 31, 2011 to the purchase price of the November 2010 Permian acquisition. The gain was recorded in the Condensed Statements of Operations under the caption Gain on purchase. For the three months ended March 31, 2010, we recorded a similar gain in conjunction with a March 2010 acquisition in the Permian.

***Transaction costs on acquisitions.*** For the three months ended March 31, 2010, we incurred $2.1 million of acquisition-related expenses in conjunction with the acquisition of certain properties in the Permian.

***Dry hole, abandonment, impairment and exploration.*** For the three months ended March 31, 2011, we incurred dry hole, abandonment, impairment and exploration expense of $0.1 million. For the three months ended March 31, 2010, we incurred dry hole, abandonment, impairment and exploration expense of $1.4 million, which was primarily a result of mechanical failure encountered on one well in the Piceance. The well was abandoned in favor of drilling a replacement well from the same pad.

***Income Tax Expense.*** The effective income tax rates for the three months ended March 31, 2011 were 40.1% compared to 36.9% for the three months ended March 31, 2010. The increase in the effective income tax rate in the first quarter of 2011 compared to the first quarter of 2010 is primarily due to a one-time reduction in the deferred state tax rate due to our reported loss in the first quarter of 2011. Our estimated annual effective income tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences. See Note 4 to the Condensed Financial Statements.

***Drilling Activity.***

The following table sets forth certain information regarding drilling activities (including operated and non-operated wells):

| | Three months ended March 31, 2011 | |
|---|---|---|
| **Asset Team** | **Gross Production Wells** | **Net Production Wells** |
| SMWSS Steam Floods | 12 | 12 |
| NMWSS—Diatomite | 76 | 76 |
| Permian | 21(1) | 14 |
| Uinta | 10 | 10 |
| E. Texas | — | — |
| Piceance | 5 | 5 |
| Totals | 124 | 117 |

(1) Includes 6 wells in which we have an average interest of approximately 0.7% each, or approximately 0.04 total net wells.

***Properties.***

We currently have six asset teams as follows: South Midway-Sunset (SMWSS)—Steam Floods, North Midway-Sunset (NMWSS)—Diatomite, Permian, Uinta, E. Texas and Piceance.

***SMWSS—Steam Floods***—Our SMWSS—Steam Floods asset team includes our Homebase, Formax, Ethel D, Placerita, and Poso Creek properties. Effective January 1, 2011, our Placerita property has been re-aligned to our SMWSS—Steam Floods asset team. In the first quarter of 2011, we drilled 12 gross (12 net) productive wells, including three horizontal producers at Homebase, one horizontal producer at Formax, one vertical producer at Formax, and seven vertical producers at Poso Creek. These new wells are currently on line or undergoing their first steam cycle. We also drilled one vertical steam injector at the Formax lease. In the second quarter of 2011, we expect to expand our Ethel D steam flood. Average daily production in the first quarter of 2011 from all of our SMWSS—Steam Floods assets was approximately 13,115 BOE/D.

***NMWSS—Diatomite***—Our NMWSS—Diatomite asset team includes our Diatomite, McKittrick and other associated properties in NMWSS. During the first quarter of 2011, we executed a two rig drilling program and drilled 76 gross (76 net) Diatomite wells. These new wells are currently on line or undergoing their first steam cycle. Wells that have completed a steam cycle are producing in line with expectations. Steam injection has steadily increased, and we exited the quarter at approximately 40,000 barrels of steam per day (BSPD). Our Diatomite production in the first quarter of 2011 averaged 2,240 BOE/D, relatively unchanged from the fourth quarter of 2010. Production from our Diatomite asset is expected to increase to 5,000 BOE/D by mid-2011 as we continue our development program and continue to increase steam volumes. Our permit for the balance of the Diatomite development is undergoing final review by the DOGGR, and full project approval is expected in the second quarter of 2011. We expect to begin the next phase of drilling in McKittrick in the third quarter of 2011. Average daily production from all of our NMWSS—Diatomite assets in the first quarter of 2011 was approximately 3,108 BOE/D.

***Permian***—During the first quarter of 2011, we executed a four rig drilling program and drilled 15 gross wells (14 net). Our drilling inventory in the Permian is approximately 400 locations on 40-acre spacing and an additional 400 locations on 20-acre spacing. Average daily production in the first quarter of 2011 from our Permian assets averaged 2,989 BOE/D, a 35% increase from the fourth quarter of 2010.

***Uinta***—During the first quarter of 2011, we drilled 10 gross wells (10 net), targeting the higher oil potential areas of Brundage Canyon. We continue to operate a one rig drilling program, with development moving to the Ashley Forest and Lake Canyon during the second quarter. Our drilling inventory in the Uinta is approximately 350 locations, distributed between Brundage Canyon, the Ashley Forest, and Lake Canyon. The Ashley Forest Environmental Impact Study continues to progress, and we anticipate approval in 2011. Average daily production from our Uinta assets averaged 5,496 BOE/D.

***E. Texas***—In 2010, we completed an eight-well Haynesville horizontal development program at Darco. All of those wells are now online, and production continues to meet our expectations. We have deferred drilling in E. Texas in 2011 while we focus on higher return oil development opportunities at our other properties. Average daily production in the first quarter of 2011 from the E. Texas assets was 34 MMcf/D.

***Piceance***—During the first quarter of 2011, we drilled five gross wells (five net) and completed two wells that continue to meet our expectations. We are currently deferring drilling in the Piceance while we focus on higher return oil development opportunities at our other properties. Average daily production in the first quarter of 2011 from the Piceance assets was 24 MMcf/D.

***Financial Condition, Liquidity and Capital Resources.***

Our development, exploitation, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our Credit Agreement as our primary sources of liquidity. We have also used the debt and equity markets as other sources of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil and natural gas directly impact the level of cash flows generated from our operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flow. As of March 31, 2011, we have approximately 69% and 44% of our expected 2011 and 2012 oil production, respectively, hedged in the form of swaps and collars. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2011 and 2012. In the future, we may increase or decrease our derivative positions. Most of our derivatives counterparties are commercial banks that are parties to our Credit Agreement, or their affiliates. See Item 3. Quantitative and Qualitative Disclosures About Market Risk below for further details concerning our hedging activities.

Our Credit Agreement has a borrowing base and lender commitments of $875 million. The maximum amount available is subject to semi-annual redeterminations of the borrowing base based on the value of our proved oil and natural gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. We and the lenders each have the unilateral right to one redetermination each year. The Credit Agreement is required to be secured by oil and natural gas properties representing at least 80% of the present value of our proved reserves. In addition, we may borrow up to $40 million for a maximum of 30 days under our Line of Credit. Our total outstanding debt at March 31, 2011 under the Line of Credit and Credit Agreement was $219 million, and $23 million of letters of credit have been issued under the Credit Agreement, leaving $633 million in borrowing capacity available.

On April 13, 2011, we amended our Credit Agreement, which extended the maturity date of the Credit Agreement to May 13, 2016 and increased the borrowing base from $875 million to $1.4 billion. Lender commitments remain unchanged at $875 million. In addition, the amendment reduced the LIBOR margin to between 1.50% and 2.50%, the prime rate margin to between 0.50% and 1.50% and the annual commitment fee on the unused portion of the credit facility to between 0.35% and 0.50%. The amendment also provides the right for us to refinance our 2014 Notes and 2016 Notes with similar notes or retire the 2014 Notes or the 2016 Notes using available borrowing under the Credit Agreement as long as certain leverage and liquidity tests are met. See Note 12 to the Condensed Financial Statements.

The debt and equity markets have served as our primary source of financing to fund large acquisitions and other transactions. In January 2010, we sold to the public 8 million shares of our common stock at a price of $29.25 per share and received $224 million of net proceeds. We used the net proceeds to fund an acquisition in the Permian in March 2010 and to reduce our outstanding borrowings under the Credit Agreement. In November 2010, we issued $300 million in principal amount of 6.75% senior notes due 2020 and received net proceeds of $294 million, which were used in part to finance an acquisition in the Permian in November 2010. The remainder was used to reduce outstanding borrowings under our Credit Agreement. Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

At March 31, 2011, we had a working capital deficit of approximately $150 million. We generally maintain a working capital deficit because we use excess cash to reduce borrowings under our Credit Agreement. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

***Credit Ratings.***

Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our Senior Notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

***Historical Cash Flows.***

***Operating Activities***—Net cash flows provided by operating activities are primarily affected by the price of crude oil and natural gas, production volumes and changes in working capital. The increase in net cash provided by operating activities of $36.9 million in the first three months of 2011 compared to the first three months of 2010 is primarily due to increased production and higher realized commodity sales prices in the first quarter of 2011 compared to the first quarter of 2010.

***Investing Activities***—Cash flows used by investing activities are primarily comprised of acquisition, exploration and development of oil and gas properties, net of dispositions of oil and gas properties.

The decrease in cash used in investing activities in the first three months of 2011 compared to the first three months of 2010 is primarily due to an acquisition in the Permian during the first quarter of 2010, offset by an increase in cash used for the exploration and development of our oil and gas properties in the first quarter of 2011 compared to the first quarter of 2010.

***Financing Activities***—Net cash provided by financing activities in the first three months of 2011 included net borrowings under our Credit Agreement and Line of Credit of $43.2 million. Net cash provided by financing activities in the first three months of 2010 included proceeds from the issuance of stock of $224 million, offset by the net repayment of borrowings under our Credit Agreement of $102 million and dividends paid of $4.0 million.

We believe that our cash flow provided by operating activities and funds available under our credit facilities will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations during 2011. However, if our revenue and cash flow decrease as a result of deterioration in economic conditions or an adverse change in commodity prices, we may have to reduce our spending levels. As we have operational control of all of our assets and we have limited drilling commitments, we believe that we have the financial flexibility to adjust our spending levels, if necessary, to meet our financial obligations.

***Reconciliation of Non-GAAP Measures.***

***Discretionary Cash Flow***—In addition to reporting cash provided by operating activities as defined under GAAP, we present discretionary cash flow, which is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of cash provided by operating activities, the most directly comparable GAAP measure, to adjusted discretionary cash flow for the period presented.

| **(in millions)** | **Three Months Ended March 31, 2011** |
|---|---|
| Net cash provided by operating activities | $ 100 |
| Add back: Net increase in current assets | 15 |
| Add back: Net increase in current liabilities including book overdraft | (30) |
| Discretionary cash flow | $ 85 |

***Operating Margin per BOE***—In addition to reporting net earnings as defined under GAAP, we present operating margin, which is a non-GAAP profitability measure. Operating margin per BOE consists of oil and gas revenues less oil and gas operating expenses and production taxes divided by the total BOE sold during the period. Management uses operating margin per BOE as a measure of profitability and believes it provides useful information to investors because it relates our oil and gas revenue and gas operating expenses to our total units of production, providing a gross margin per unit of production. Using this measure, investors can evaluate how profitability varies on a per unit basis each period.

| (per BOE) | Three Months Ended March 31, 2011 |
|---|---|
| Average sales price including cash derivative settlements | $ 59.01 |
| Average operating costs—oil and gas production | 18.44 |
| Average production taxes | 2.39 |
| Average operating margin | $ 38.18 |

### *Item 3. Quantitative and Qualitative Disclosures About Market Risk*

As discussed in Note 8 to the Condensed Financial Statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas derivative contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing, as we are a consumer of natural gas in our operations, and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate and in accordance with policy established by our board of directors. Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or the index gas price. A two-way collar is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. We utilize costless collars which is an options position by which the proceeds from the sale of the call option fund the purchase of a put option.

As of March 31, 2011, we have approximately 69% and 44% of our expected 2011 and 2012 oil production, respectively, hedged in the form of swaps and collars. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our crude oil derivative instruments at March 31, 2011 would decrease the respective fair value of crude oil and natural gas derivative instruments at March 31, 2011 by $123 million and $5 million, respectively. A hypothetical $10 decrease in the oil prices used and $1 decrease in the natural gas prices used to calculate the fair values of our crude oil derivative instruments at March 31, 2011 would increase the respective fair value of crude oil and natural gas derivative instruments at March 31, 2011 by $110 million and $6 million, respectively.

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The following table summarizes our commodity derivative position as of March 31, 2011:

| Term | Average Barrels/MMBtu Per Day | Average Prices |
|---|---|---|
| **Crude Oil Sales (NYMEX WTI) Collars** | | |
| Full year 2011 | 270 | $80.00/$90.00 |
| Full year 2011 | 1,000 | $55.20/$70.00 |
| Full year 2011 | 1,000 | $55.00/$70.50 |
| Full year 2011 | 1,000 | $55.00/$68.65 |
| Full year 2011 | 1,000 | $55.00/$68.00 |
| Full year 2011 | 1,000 | $55.00/$71.20 |
| Full year 2011 | 1,000 | $60.00/$76.00 |
| Full year 2011 | 1,000 | $60.00/$81.25 |
| Full year 2011 | 500 | $75.00/$101.15 |
| Full year 2011 | 500 | $75.00/$100.75 |
| Full year 2011 | 1,000 | $75.00/$91.25 |
| Full year 2012 | 1,000 | $63.00/$82.60 |
| Full year 2012 | 1,000 | $63.00/$83.50 |
| Full year 2012 | 1,000 | $70.00/$93.00 |
| Full year 2012 | 500 | $75.00/$106.00 |
| Full year 2012 | 500 | $75.00/$105.00 |
| Full year 2012 | 1,000 | $75.00/$95.00 |
| **Crude Oil Sales (NYMEX WTI) Swaps** | | |
| Full year 2011 | 500 | $57.36 |
| Full year 2011 | 500 | $57.40 |
| Full year 2011 | 500 | $57.50 |
| Full year 2011 | 250 | $61.80 |
| **Natural Gas Sales (NYMEX HH) Swaps** | | |
| Full year 2011 | 5,000 | $6.89 |
| Full year 2011 | 5,000 | $5.50 |
| Full year 2012 | 5,000 | $7.16 |
| Full year 2012 | 5,000 | $5.75 |
| **Natural Gas Sales (NYMEX HH) Collars** | | |
| Full year 2011 | 5,000 | $6.00/$7.25 |
| Full year 2012 | 5,000 | $6.00/$7.70 |
| **Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps** | | |
| Full year 2011 | 2,500 | $0.460 |
| Full year 2012 | 2,500 | $0.440 |
| **Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps** | | |
| Full year 2011 | 2,500 | $0.325 |
| Full year 2012 | 2,500 | $0.325 |
| Full year 2012 | 2,500 | $0.320 |

| Term | Average Barrels Per Day | Average Prices |
|---|---|---|
| **Crude Oil Sales (NYMEX WTI) Three-Way Collars** | | |
| Full year 2011 | 500 | $65.00/$85.00/$97.25 |
| Full year 2011 | 1,000 | $70.00/$87.00/$105.00 |
| Full year 2011 | 1,000 | $55.00/$75.00/$91.63 |
| Full year 2011 | 1,000 | $60.00/$80.00/$101.00 |
| Full year 2011 | 1,000 | $70.00/$88.15/$100.00 |
| Full year 2011 | 1,000 | $70.00/$86.85/$100.00 |
| Full year 2011 | 1,000 | $69.70/$85.00/$100.00 |
| Full year 2011 | 500 | $70.00/$85.00/$94.68 |
| Feb-Dec 2011 | 1,000 | $70.00/$90.00/$116.50 |
| Full year 2012 | 1,000 | $65.00/$85.00/$97.25 |
| Full year 2012 | 1,000 | $70.00/$87.00/$105.00 |
| Full year 2012 | 1,000 | $70.00/$88.00/$106.00 |
| Full year 2012 | 1,000 | $60.00/$80.00/$96.92 |
| Full year 2012 | 1,000 | $60.00/$80.00/$120.00 |
| Full year 2012 | 1,000 | $70.00/$88.15/$100.00 |
| Full year 2012 | 1,000 | $70.00/$86.85/$100.00 |
| Full year 2012 | 1,000 | $69.70/$85.00/$100.00 |
| Full year 2012 | 1,000 | $70.00/$87.00/$108.50 |
| Full year 2012 | 1,000 | $70.00/$90.00/$116.50 |
| Full year 2012 | 1,000 | $70.00/$90.00/$120.00 |
| Full year 2012 | 1,000 | $70.00/$95.00/$120.10 |
| Full year 2013 | 1,000 | $65.00/$85.00/$97.25 |
| Full year 2013 | 1,000 | $70.00/$87.00/$105.00 |
| Full year 2013 | 1,000 | $70.00/$88.00/$106.00 |
| Full year 2013 | 1,000 | $60.00/$80.00/$103.30 |
| Full year 2013 | 1,000 | $70.00/$88.15/$100.00 |
| Full year 2013 | 1,000 | $70.00/$86.85/$100.00 |
| Full year 2013 | 1,000 | $69.70/$85.00/$100.00 |
| Full year 2013 | 1,000 | $70.00/$87.00/$108.50 |
| Full year 2013 | 1,000 | $70.00/$90.00/$116.50 |
| Full year 2013 | 1,000 | $70.00/$90.00/$120.00 |
| Full year 2013 | 1,000 | $70.00/$95.00/$120.10 |

***Interest Rate Risk.***

Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the Credit Agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At March 31, 2011, our outstanding principal balance under our Credit Agreement was $205 million and the weighted average interest rate on the outstanding principal balance was 2.3%. At March 31, 2011, the carrying amount approximated fair market value. Assuming a constant debt level of $1.2 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $1.3 million over a 12-month time period.

***Item 4. Controls and Procedures***

As of March 31, 2011, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of March 31, 2011, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and include controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting that occurred during the three months ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

***Forward Looking Statements***

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s)," "anticipate," "estimate" or other comparable words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 1, 2011, under the heading "Risk Factors".

## PART II. OTHER INFORMATION

### *Item 1. Legal Proceedings*

The information set forth under "Legal Matters" in Note 11 of our Notes to Condensed Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

### *Item 1A. Risk Factors*

For information about our risk factors, see Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on March 1, 2011.

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

None.

### *Item 3. Defaults Upon Senior Securities*

None.

### *Item 4. Removed and Reserved*

None.

### *Item 5. Other Information*

None.

***Item 6. Exhibits***

| Exhibit No. | Description of Exhibit |
|---|---|
| 4.1 | First Amendment to the Second Amended and Restated Credit Agreement dated April 13, 2011 by and among the Registrant and Wells Fargo Bank, N.A. and other lenders (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 13, 2011, File No. 1-9735) |
| 10.1 | Form of Stock Award Agreement—Directors (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.2 | Form of Restricted Stock Unit Agreement—Employees (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.3 | Form of Restricted Stock Unit Agreement—Officers (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.4 | Form of Stock Option Award Agreement (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.5 | Form of Award Grant under the Performance Share Award Program for select officers of the Registrant (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.6 | Award Grant under the Performance Share Award Program to Robert H. Heinemann (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.7 | Award Grant under the Performance Share Award Program to Michael Duginski (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 10.8 | Award Grant under the Performance Share Award Program to David D. Wolf (filed as Exhibit 10.8 to the Registrant's Current Report on Form 8-K filed on March 4, 2011, File No. 1-9735) |
| 12.1* | Computation of Ratio of Earnings to Fixed Charges |
| 31.1* | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2* | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1* | Certification of Chief Executive Officer 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 pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS** | XBRL Instance Document |
| 101.SCH** | XBRL Taxonomy Extension Schema Document |
| 101.CAL** | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF** | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB** | XBRL Taxonomy Label Linkbase Document |
| 101.PRE** | XBRL Taxonomy Extension Presentation Linkbase Document |

* Filed herewith.

** 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 thereto duly authorized.

BERRY PETROLEUM COMPANY

/s/ JAMIE L. WHEAT

Jamie L. Wheat
*Controller*
*(Principal Accounting Officer)*
Date: April 29, 2011

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**Exhibit 12.1**

**COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES**

(in thousands, except ratios)

| | Three Months Ended March 31, 2011 | For the Year Ended 12/31/10 | 12/31/09 | 12/31/08 | 12/31/07 | 12/31/06 |
|---|---|---|---|---|---|---|
| Pre-tax earnings from continuing operations | $ (87,628) | $ 136,492 | $ 67,888 | $ 190,193 | $ 195,616 | $ 158,191 |
| Interest expense | 15,655 | 66,541 | 50,738 | 26,209 | 17,287 | 10,247 |
| Capitalized interest | 10,392 | 28,321 | 30,107 | 23,209 | 18,104 | 9,339 |
| Earnings | $ (71,539) | $ 203,033 | $ 118,626 | $ 216,402 | $ 212,903 | $ 168,438 |
| Ratio of earnings to fixed charges | (2.8) | 2.1 | 1.5 | 4.4 | 6.0 | 8.6 |

For purposes of this table, "earnings" consists of income before income taxes from continuing operations plus fixed charges and less capitalized interest. "Fixed charges" consists of interest expense and capitalized interest (for both continuing and discontinued operations).

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**Exhibit 31.1**

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-(e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, and its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ ROBERT F. HEINEMANN

Robert F. Heinemann
*President, Chief Executive Officer and Director*

April 29, 2011

**Exhibit 31.2**

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-(e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

| | |
|---|---|
| | /s/ DAVID D. WOLF |
| April 29, 2011 | David D. Wolf<br>*Executive Vice President and Chief Financial Officer* |

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**Exhibit 32.1**

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending March 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ROBERT F. HEINEMANN

Robert F. Heinemann
*President, Chief Executive Officer and Director*

April 29, 2011

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**Exhibit 32.2**

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending March 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David D. Wolf, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DAVID D. WOLF

David D. Wolf
*Executive Vice President and Chief Financial Officer*

April 29, 2011