PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 06, 2008

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

FORM 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2008

OR

o Transition Report Pursuant to Section 13 of 15(d) of the Securities Exchange Act of 1934
For the transition period from to

Commission File Number: 000-07246

PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Nevada | 95-2636730 |
| (State of incorporation) | (I.R.S. Employer Identification No.) |

120 Genesis Boulevard
Bridgeport, West Virginia 26330
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (304) 842-3597

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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer o | Accelerated filer x |
| 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 Exchange Act). Yes [ ] No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,862,225 shares of the Company's Common Stock ($.01 par value) were outstanding as of October 31, 2008.

PETROLEUM DEVELOPMENT CORPORATION

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PART 1 – FINANCIAL INFORMATION



PART II – OTHER INFORMATION

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## PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

Petroleum Development Corporation
Condensed Consolidated Balance Sheets
(in thousands, except share and per share data)

| | September 30, 2008 | December 31, 2007* |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 47,404 | $ 84,751 |
| Accounts receivable, net | 67,386 | 60,024 |
| Accounts receivable - affiliates | 19,547 | 11,537 |
| Fair value of derivatives | 56,713 | 4,817 |
| Other current assets | 45,583 | 30,664 |
| Total current assets | 236,633 | 191,793 |
| Properties and equipment, net | 987,737 | 845,864 |
| Restricted cash - long term | 2,150 | 1,294 |
| Other assets | 52,481 | 11,528 |
| Total assets | $ 1,279,001 | $ 1,050,479 |
| | | |
| Liabilities and shareholders' equity | | |
| Current liabilities: | | |
| Accounts payable | $ 88,225 | $ 88,502 |
| Accounts payable - affiliates | 16,932 | 3,828 |
| Federal and state income taxes payable | 1,580 | 901 |
| Fair value of derivatives - current | 13,840 | 6,291 |
| Advances for future drilling contracts | 5,157 | 68,417 |
| Funds held for future distribution | 70,354 | 39,823 |
| Other accrued expenses | 35,803 | 34,243 |
| Total current liabilities | 231,891 | 242,005 |
| Long-term debt | 322,294 | 235,000 |
| Deferred income taxes | 183,362 | 136,490 |
| Other liabilities | 71,551 | 40,699 |
| Total liabilities | 809,098 | 654,194 |
| | | |
| Commitments and contingencies | | |
| | | |
| Minority interest in consolidated limited liability company | 710 | 759 |
| | | |
| Preferred shares, par value $.01 per share; authorized: 50,000,000 shares; issued: none | - | - |
| Common shares, par value $.01 per share; authorized: 100,000,000 shares; issued: 14,907,679 in 2007 and 14,861,299 in 2008 | 149 | 149 |
| Additional paid-in capital | 4,465 | 2,559 |
| Retained earnings | 464,853 | 393,044 |
| Treasury shares at cost | (274) | (226) |

| | | |
|---|---|---|
| Total shareholders' equity | 469,193 | 395,526 |
| Total liabilities and shareholders' equity | $ 1,279,001 | $ 1,050,479 |

*Derived from audited 2007 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Operations
(unaudited; in thousands except per share data)

| | Three Months Ended September 30, 2008 | Three Months Ended September 30, 2007 | Nine Months Ended September 30, 2008 | Nine Months Ended September 30, 2007 |
|---|---|---|---|---|
| Revenues: | | | | |
| Oil and gas sales | $ 99,422 | $ 44,437 | $ 265,617 | $ 117,699 |
| Sales from natural gas marketing activities | 53,372 | 19,934 | 107,638 | 71,845 |
| Oil and gas well drilling operations | 1,232 | 1,573 | 7,202 | 7,342 |
| Well operations and pipeline income | 3,356 | 2,092 | 8,146 | 6,682 |
| Oil and gas price risk management gain, net | 169,402 | 6,345 | 25,294 | 4,442 |
| Other | 20 | 1,894 | 57 | 2,122 |
| Total revenues | 326,804 | 76,275 | 413,954 | 210,132 |
| | | | | |
| Costs and expenses: | | | | |
| Oil and gas production and well operations cost | 22,173 | 12,645 | 61,120 | 33,308 |
| Cost of natural gas marketing activities | 54,372 | 19,810 | 106,610 | 70,102 |
| Cost of oil and gas well drilling operations | 501 | 749 | 1,097 | 1,559 |
| Exploration expense | 10,212 | 5,337 | 17,962 | 14,795 |
| General and administrative expense | 8,106 | 7,513 | 27,160 | 21,823 |
| Depreciation, depletion and amortization | 28,645 | 20,354 | 71,881 | 50,857 |
| Total costs and expenses | 124,009 | 66,408 | 285,830 | 192,444 |
| | | | | |
| Gain on sale of leaseholds | - | - | - | 25,600 |
| | | | | |
| Income from operations | 202,795 | 9,867 | 128,124 | 43,288 |
| Interest income | 151 | 462 | 497 | 2,059 |
| Interest expense | (7,817) | (2,544) | (19,143) | (4,825) |
| | | | | |
| Income before income taxes | 195,129 | 7,785 | 109,478 | 40,522 |
| Provision for income taxes | 68,233 | 3,326 | 37,222 | 15,511 |
| Net income | $ 126,896 | $ 4,459 | $ 72,256 | $ 25,011 |
| | | | | |
| Earnings per share | | | | |
| Basic | $ 8.59 | $ 0.30 | $ 4.90 | $ 1.70 |
| Diluted | $ 8.55 | $ 0.30 | $ 4.86 | $ 1.68 |
| Weighted average common shares outstanding | | | | |
| Basic | 14,767 | 14,757 | 14,749 | 14,739 |
| Diluted | 14,835 | 14,827 | 14,858 | 14,845 |

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2008 | 2007 |
| Cash flows from operating activities: | | |
| Net income | $ 72,256 | $ 25,011 |
| Adjustments to net income to reconcile to cash provided by (used in) operating activities: | | |
| Deferred income taxes | 45,390 | 14,833 |
| Depreciation, depletion and amortization | 71,881 | 50,857 |
| Allowance for doubtful accounts | 130 | - |
| Amortization of debt issuance costs | 956 | 280 |
| Accretion of asset retirement obligation | 916 | 712 |
| Exploratory dry hole costs | 5,038 | 969 |
| Gain from sale of assets | (88) | (1) |
| Gain from sale of leaseholds | - | (25,600) |
| Expired and abandoned leases | 3,492 | 1,246 |
| Stock-based compensation | 5,239 | 1,652 |
| Unrealized gain on derivative transactions | (45,371) | (1,256) |
| Excess tax benefits from stock based compensation | (1,136) | (500) |
| Increase in current assets | (28,138) | (34,879) |
| (Increase) decrease in other assets | (255) | 220 |
| Decrease in current liabilities | (27,873) | (68,302) |
| Increase in other liabilities | 1,355 | 1,958 |
| | | |
| Net cash provided by (used in) operating activities | 103,792 | (32,800) |
| | | |
| Cash flows from investing activities: | | |
| Capital expenditures | (219,273) | (158,727) |
| Acquisitions | - | (201,594) |
| Decrease in restricted cash for property acquisition | - | 191,178 |
| Other | 121 | 684 |
| | | |
| Net cash used in investing activities | (219,152) | (168,459) |
| | | |
| Cash flows from financing activities: | | |
| Proceeds from credit facility | 339,500 | 238,000 |
| Proceeds from senior notes | 200,101 | - |
| Repayment of credit facility | (452,500) | (203,000) |
| Payment of debt issuance costs | (5,308) | (591) |
| Proceeds from exercise of stock options | 605 | 182 |
| Excess tax benefits from stock based compensation | 1,136 | 500 |
| Minority interest investment | - | 800 |
| Purchase of treasury stock | (5,521) | (346) |

| | | | | |
|---|---|---|---|---|
| Net cash provided by financing activities | | 78,013 | | 35,545 |
| | | | | |
| Net decrease in cash and cash equivalents | | (37,347) | | (165,714) |
| Cash and cash equivalents, beginning of period | | 84,751 | | 194,326 |
| Cash and cash equivalents, end of period | $ | 47,404 | $ | 28,612 |
| | | | | |
| Supplemental disclosure of cash flow information of cash payments for: | | | | |
| Interest | $ | 18,847 | $ | 6,991 |
| Income taxes | | 9,224 | | 43,615 |
| Supplemental schedule of non-cash investing and financing activities: | | | | |
| Change in deferred tax liability resulting from the allocation of acquisition purchase price | | - | | 4,188 |
| Changes in accounts payable related to the acquisitions of partnerships | | - | | 668 |
| Changes in accounts payable related to purchase of properties and equipment | | 6,481 | | 34,150 |
| Changes in accounts payable-affiliates related to investment in drilling partnership | | - | | 18,712 |
| Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals | | 631 | | 5,527 |

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
September 30, 2008
(unaudited)

## 1. GENERAL

Petroleum Development Corporation ("PDC"), together with our consolidated entities (the "Company"), is an independent energy company engaged primarily in the exploration, development, production and marketing of oil and natural gas. Since we began oil and natural gas operations in 1969, we have grown primarily through exploration and development activities, the acquisition of producing oil and natural gas wells and the expansion of our natural gas marketing activities.

The accompanying interim condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. Minority interest in earnings and ownership has been recorded for the percentage of the LLC we do not own. We account for our investment in interests in oil and natural gas limited partnerships under the proportionate consolidation method. Accordingly, our accompanying interim condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships has been eliminated.

The accompanying interim condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission ("SEC"). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. In our opinion, the accompanying interim condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly our financial position, results of operations and cash flows for the periods presented. The interim results of operations for the nine months ended September 30, 2008, and the interim cash flows for the same interim period, are not necessarily indicative of the results to be expected for the full year or any other future period.

The accompanying interim condensed consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2007, as filed with the SEC on March 20, 2008 ("2007 Form 10-K").

## 2. RECENT ACCOUNTING STANDARDS

### Recently Adopted Accounting Standards

We adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 157, Fair Value Measurements, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and nonfinancial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances. In February 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FAS No. 157-2, Effective Date of FASB Statement No. 157, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Nonfinancial assets and liabilities for which we have not applied the provisions of SFAS No. 157 include those initially measured at fair value, including our asset retirement obligations. As of the adoption date, we have applied the provisions of SFAS No. 157 to our recurring measurements and the impact was not material to our underlying fair values and no amounts were recorded relative to the cumulative effect of a change in accounting. We are currently evaluating the potential effect that the nonfinancial assets and liabilities provisions of SFAS No. 157 will have on our financial statements when adopted in 2009. See Note 5 for further details on our fair value measurements.

In October 2008, the FASB issued FSP No. FAS 157-3, Determining the Fair Value of a Financial Asset in a Market That Is Not Active, which applies to financial assets within the scope of accounting pronouncements that require or permit fair value measurements in accordance with SFAS No. 157. This FSP clarifies the application of SFAS No. 157 in a market that is not active and defines additional key criteria in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 was effective upon issuance and did not have a material impact on our financial statements.

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In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. SFAS No. 159 permits entities to choose to measure, at fair value, many financial instruments and certain other items that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. As of September 30, 2008, we had not elected, nor do we intend, to measure additional financial assets and liabilities at fair value.

In April 2007, the FASB issued FSP No. FIN 39-1, Amendment of FASB Interpretation No. 39 ("FIN 39-1"), to amend certain portions of Interpretation 39. FIN 39-1 replaces the terms "conditional contracts" and "exchange contracts" in Interpretation 39 with the term "derivative instruments" as defined in Statement 133. FIN 39-1 also amends Interpretation 39 to allow for the offsetting of fair value amounts for the right to reclaim cash collateral or receivable, or the obligation to return cash collateral or payable, arising from the same master netting arrangement as the derivative instruments. FIN 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. The January 1, 2008, adoption of FSP FIN 39-1 had no impact on our financial statements.

Recently Issued Accounting Standards

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations ("SFAS No. 141R"). SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS No. 141R will become effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R will become effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109, Accounting for Income Taxes, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, Accounting for Uncertainty in Income Taxes, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements—An Amendment of ARB No. 51. SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. Additionally, SFAS No. 160 establishes reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS No. 160 is effective as of the beginning of an entity’s first fiscal year beginning after December 15, 2008. We are evaluating the impact that SFAS No. 160 will have, if any, on our consolidated financial statements and related disclosures when it is adopted in 2009.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—An Amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. As SFAS No. 161 is disclosure related, we do not expect its adoption to have a material impact on our financial statements.

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3. PROPERTIES AND EQUIPMENT

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in thousands) | |
| Properties and equipment, net: | | |
| Oil and gas properties (successful efforts method of accounting) | | |
| Proved | $ 1,152,534 | $ 953,904 |
| Unproved | 40,365 | 41,023 |
| Total oil and gas properties | 1,192,899 | 994,927 |
| Pipelines and related facilities | 31,190 | 22,408 |
| Transportation and other equipment | 29,296 | 23,669 |
| Land and buildings | 14,449 | 11,303 |
| Construction in progress (1) | - | 2,929 |
| | 1,267,834 | 1,055,236 |
| Accumulated depreciation, depletion and amortization ("DD&A") | (280,097) | (209,372) |
| | $ 987,737 | $ 845,864 |

(1) At December 31, 2007, includes costs primarily related to a new integrated oil and gas financial software system.

Suspended Well Costs.

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in properties and equipment in the accompanying condensed consolidated balance sheets.

| | Amount (in thousands) | Number of Wells |
|---|---|---|
| Beginning balance at December 31, 2007 | $ 2,300 | 3 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | 13,526 | 13 |
| Reclassifications to wells, facilities and equipment based on the determination of proved reserves | (7,626) | (6) |
| Capitalized exploratory well costs charged to expense | (5,040) | (3) |
| Ending balance at September 30, 2008 | $ 3,160 | 7 |

As of September 30, 2008, none of the seven suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year.

4. DERIVATIVE FINANCIAL INSTRUMENTS

Our derivative instruments do not qualify for use of hedge accounting under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, as amended. Accordingly, we recognize all derivative instruments as either assets or liabilities on our accompanying condensed consolidated balance sheets at fair value, and changes in the derivatives' fair values are recorded on a net basis in our accompanying condensed consolidated statements of operations. Changes in fair value of derivative instruments related to our oil and gas sales activity are recorded in oil and gas price risk management, net, and changes in fair value of derivatives related to our natural gas marketing activities are recorded in sales from and cost of natural gas marketing activities.

We are exposed to the effect of market fluctuations in the prices of oil and natural gas as they relate to our oil and natural gas sales and natural gas marketing segments. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivatives. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

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Economic Hedging Strategies.  Our results of operations and operating cash flows are also affected by changes in market prices for oil and natural gas.  To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2008, our oil and natural gas derivative instruments were comprised of futures, swaps and collars.  These instruments generally consist of (i) New York Mercantile Exchange ("NYMEX") -traded natural gas for Appalachian and Michigan production, (ii) Panhandle Eastern Pipeline ("PEPL") -based contracts for Northeastern Colorado ("NECO") production, (iii) Colorado Interstate Gas Index ("CIG") -based contracts for other Colorado production and (iv) NYMEX-based swaps for our Colorado oil production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price to the counterparty.  The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Collars contain a fixed floor price (put) and ceiling price (call).  If the market price exceeds the call strike price or falls below the fixed put strike price, we receive the fixed price and pay the market price.  If the market price is between the call and the put strike price, no payments are due from either party.

We enter into derivative instruments for our own and affiliate partnerships' production to protect against price declines in future periods.

With regard to our natural gas marketing activities, we enter into fixed-price physical purchase and sale agreements that are derivative contracts.  In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.  While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market.

We believe our economic hedging strategies continue to be effective in achieving the risk management objectives for which they were intended.

The following table summarizes the estimated fair value of our oil and natural gas derivative positions as of:

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in thousands) | |
| Derivative assets (liabilities) | | |
| Oil and gas sales activities: | | |
| Fixed-price natural gas swaps | $ 51,242 | $ - |
| Natural gas floors | - | 105 |
| Natural gas collars | 26,258 | 2,969 |
| Fixed-price oil swaps | (19,326) | (5,097) |
| | 58,174 | (2,023) |
| Natural gas marketing activities: | | |
| Fixed-price natural gas swaps | 207 | 649 |
| Natural gas collars | 3 | - |
| | 210 | 649 |
| Estimated net fair value of derivative instruments | $ 58,384 | $ (1,374) |

In addition to including the gross assets and liabilities for derivative positions related to our share of oil and gas production, the above tables and our condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into as the managing general partner on behalf of our affiliate partnerships. Our condensed consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of $12.9 million at September 30, 2008, and a $1.5 million net receivable from the partnerships at December 31, 2007.

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The following table identifies the fair value of commodity based derivatives as classified in our condensed consolidated balance sheets.

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in thousands) | |
| Classification in the Condensed Consolidated Balance Sheets: | | |
| Fair value of derivatives - current asset | $ 56,713 | $ 4,817 |
| Other assets - long-term asset | 26,921 | 193 |
| | 83,634 | 5,010 |
| | | |
| Fair value of derivatives - current liability | 13,840 | 6,291 |
| Fair value of derivatives - long term liability | 11,410 | 93 |
| | 25,250 | 6,384 |
| Net fair value of commodity based derivatives | $ 58,384 | $ (1,374) |

The following changes in the fair value of commodity based derivatives are reflected in the condensed consolidated statements of income:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2008 | | 2007 | |
| Statement of operations line item | Realized | Unrealized | Realized | Unrealized |
| | (in thousands, gain/(loss)) | | | |
| Oil and gas price risk management gain (loss), net (1) | $ (2,752) | $ 172,154 | $ 2,491 | $ 3,854 |
| Sales from natural gas marketing activities | (1,570) | 18,024 | 1,477 | 12 |
| Cost of natural gas marketing activities | 1 | (19,151) | (108) | (87) |

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2008 | | 2007 | |
| Statement of operations line item | Realized | Unrealized | Realized | Unrealized |
| | (in thousands, gain/(loss)) | | | |
| Oil and gas price risk management gain (loss), net (1) | $ (20,517) | $ 45,811 | $ 3,098 | $ 1,344 |
| Sales from natural gas marketing activities | (3,367) | 1,333 | 2,805 | (1,256) |
| Cost of natural gas marketing activities | 119 | (1,773) | (331) | 1,168 |

(1) Represents net realized and unrealized gain and loss on commodity based derivative instruments related to oil and gas sales.

5. FAIR VALUE MEASUREMENTS

As described above in Note 2, in September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. We adopted the provisions of SFAS No. 157 effective January 1, 2008.

Valuation hierarchy. SFAS No. 157 establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Instruments included in Level 1 consist of our commodity derivatives for NYMEX-based natural gas swaps.

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Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments included in Level 3 consist of our commodity derivatives for CIG and PEPL based natural gas swaps, oil swaps, oil and natural gas options, and physical sales and purchases.

Determination of fair value. We measure fair value based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to our nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We have evaluated the credit risk of our receivables from our counterparties using credit default swap values for each counterparty with the outstanding hedge positions for the appropriate time period to calculate the maximum exposure. We have evaluated our exposure and determined that it is immaterial. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents, for each hierarchy level, our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of September 30, 2008:

| | Level 1 | Level 3 | Total |
|---|---|---|---|
| | | (in thousands) | |
| Assets: | | | |
| Commodity based derivatives | $ 9,478 | $ 74,156 | $ 83,634 |
| Liabilities: | | | |
| Commodity based derivatives | (324) | (24,926) | (25,250) |
| Net fair value of commodity based derivatives | $ 9,154 | $ 49,230 | $ 58,384 |

The following table sets forth a reconciliation of our Level 3 fair value measurements:

| | September 30, 2008 | |
|---|---|---|
| | Three Months Ended | Nine Months Ended |
| | (in thousands) | |
| Fair value, beginning of period (1) | $ (141,453) | $ (2,368) |
| Total realized and unrealized gains or (losses): | | |

| | | | | |
|---|---|---|---|---|
| Included in oil and gas price risk management gain, net | | 167,755 | | 124,234 |
| Included in sales from natural gas marketing activities | | 1,864 | | 1,807 |
| Included in cost of natural gas marketing activities | | 17 | | 2,650 |
| Purchases, issuances and settlements, net | | 21,047 | | (77,093) |
| Fair value, end of period | $ | 49,230 | $ | 49,230 |
| | | | | |
| Total gains (losses) attributable to the change in unrealized (loss), relating to assets still held as of September 30, 2008: | | | | |
| Included in oil and gas price risk management gain, net | $ | 167,755 | $ | 124,234 |
| Included in sales from natural gas marketing activities | | 1,864 | | 1,807 |
| Included in cost of natural gas marketing activities | | 17 | | 2,650 |
| Total | $ | 169,636 | $ | 128,691 |

(1) Derivative assets and liabilities are presented on a net basis.

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6. LONG-TERM DEBT

Long-term debt consists of the following:

| | September 30, 2008 | | December 31, 2007 | |
|---|---|---|---|---|
| | (in thousands) | | | |
| Credit facility | $ | 122,000 | $ | 235,000 |
| 12% Senior notes due 2018, net of discount of $2.7 million | | 200,294 | | - |
| Total long-term debt | $ | 322,294 | $ | 235,000 |

Credit facility

We have a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended last on July 18, 2008, dated as of November 4, 2005, with an activated commitment of $300 million as of September 30, 2008. The credit facility, through a series of amendments, includes commitments from: Wachovia Bank N.A.; Bank of Oklahoma; Allied Irish Banks p.l.c.; Guaranty Bank, FSB; Royal Bank of Canada; The Royal Bank of Scotland, plc; Calyon New York Branch; Compass Bank; The Bank of Nova Scotia; and BMO Capital Markets Financing, Inc. The maximum allowable commitment under the current credit facility is $400 million, of which we currently have bank commitments for $300 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. We are required to pay a commitment fee of .375% to .50% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus .5%. ABR borrowings are assessed an additional margin spread up to .625% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.375% to 2.125%, based upon the outstanding balance under the credit facility. The credit agreement requires, among other things, the maintenance of certain working capital and tangible net worth ratios. No principal payments are required until the credit agreement expires on November 4, 2010.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, (g) enter into transactions with our affiliates, (h) change the character of our business, (i) engage in hedging activities unless certain requirements are satisfied, (j) issue certain types of stock, and (k) make certain amendments to our organizational documents. The credit facility also requires us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. In addition, we are required to comply with certain financial tests and maintain certain financial ratios. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, or working capital ratio, and (b) not to exceed a maximum leverage ratio.

As of September 30, 2008, we had drawn $122 million from our credit facility compared to $235 million as of December 31, 2007. The borrowing rate on the outstanding balance was 4.8% as of September 30, 2008 compared to 7.1% as of December 31, 2007. Amounts outstanding under our credit facility are secured by substantially all of our properties. We were in compliance with all covenants at September 30, 2008, and expect to remain in compliance throughout 2008.

We are in the process of soliciting our bank syndicate and additional banks to increase our revolving bank credit facility borrowing base and related bank commitments by $75 million to $375 million. While we can make no assurances as to the success of this initiative, we remain encouraged by its progress to date. We expect to finalize this transaction in early November.

12% Senior Notes Due 2018

Our outstanding 12% senior notes were issued on February 8, 2008. The principal amount of the senior notes is $203 million, which is payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15. The first payment was paid on August 15, 2008. The senior notes were issued at a price of 98.572% of the principal amount. In addition, we capitalized $5.4 million in costs associated with the issuance of the debt which has been capitalized as a deferred loan cost. The original discount and the deferred loan costs are being amortized to interest expense over the term of the debt using the effective interest method.

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As a result of recent global financial market conditions, as of September 30, 2008 we estimate the fair value of the senior notes at approximately $191 million or approximately 94% of par value. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders active in the trading of the securities. The liability is recorded at unamortized, original issue discount.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. We were in compliance with all covenants as of September 30, 2008, and expect to remain in compliance throughout 2008.

The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if:

- a subsidiary is a guarantor under our senior credit facility; and
- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture. As of September 30, 2008, none of our subsidiaries were obligated as guarantors of our senior notes.

The indenture provides that at any time, which may be more than once, before February 15, 2011, we may redeem up to 35% of the outstanding notes with proceeds from one or more equity offerings at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest, as long as:

- at least 65% of the aggregate principal amount of the notes issued on February 8, 2008 remains outstanding after each such redemption; and
- the redemption occurs within 180 days after the closing of the equity offering.

The notes also provide that we may, at our option, redeem all or part of the notes, at any time prior to February 15, 2013, at the make-whole price set forth in the indenture, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption. Further, the indenture provides that upon a change of control, we must give holders of the notes the opportunity to put their notes to us for repurchase at a repurchase price of 101% of the principal amount, plus accrued and unpaid interest.

In connection with the issuance of the notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC related to an offer to exchange the notes for other freely tradable notes and to use commercially reasonable efforts to cause the registration statement to become effective on or prior to February 7, 2009. On April 24, 2008, we filed the related registration statement on Form S-4. The registration statement was declared effective May 23, 2008.

7. COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. In connection with the acquisition of oil and gas properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells in the Appalachian Basin by January 2016. We have plans to drill over 35 of these wells in 2008. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of $25,000 per undrilled well for a total contingent obligation of $2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of September 30, 2008, we have drilled 14 wells pursuant to this agreement.

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In September 2008, we entered into a pipeline and processing plants expansion agreement with an unrelated party, who is currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to make a capital investment, for our own benefit, over a three-year period commencing on January 1, 2009, to develop or facilitate production in our Wattenberg Field dedicated to this purchaser. The agreement also provides for certain volume commitments to be obtained by December 31, 2012. Qualifying capital expenditures include the cost to drill new wells and the cost to recomplete existing wells in this area. Should we not meet the commitments, we will be required to pay a deficiency payment of up to $25 million. At this time, we expect to meet the commitments of this agreement.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to our financial ability to do so. The maximum annual repurchase obligation as of September 30, 2008, was approximately $12.9 million. We have adequate liquidity to meet this obligation. During the nine months of 2008 and for 2007, we paid $1.5 million and $1.6 million, respectively, under this provision for the repurchase of partnership units.

Partnership Casualty Losses. As managing general partner of 33 partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

Drilling Rig Contracts. In order to secure the services for drilling rigs, we made commitments to the drilling contractors, which call for a minimum commitment of $12,500 daily for a specified amount of time if we cease to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $40,680 daily for a specified amount of time for daily use of the drilling rigs. Commitments for these two separate contracts expire in August 2009 and July 2010. For the drilling rig commitment which expires in August 2009, we have sub-leased the drilling rig to an unrelated party and expect to incur no additional cost on such contract. As of September 30, 2008, we have an outstanding minimum commitment for $5.3 million and an outstanding maximum commitment for $19.4 million.

Royalty litigation. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells operated by us in parts of the State of Colorado (the "Droegemueller Action"). The plaintiff sought declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007. On October 10, 2008, the court preliminarily approved a settlement agreement between the plaintiffs and the Company, on behalf of itself and the partnerships for which the Company is the managing general partner. Based on the settlement terms, the settlement amount payable by the Company is $5.8 million. Such moneys, in addition to moneys related to the settlement on behalf of the partnerships for which the Company is the managing general partner, were deposited in an escrow account on November 3, 2008. We have accrued as of September 30, 2008, and included in other accrued expenses in the accompanying condensed consolidated balance sheet, a related $5.8 million litigation reserve. We believe that the amount accrued is adequate to satisfy this obligation. Notice of the settlement will be mailed to members of the class action suit in mid November 2008. The final settlement approval hearing is expected in the first quarter of 2009.

We are involved in various other legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position or results of operations.

Employment Agreements with Executive Officers. We have employment agreements with our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and other executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation, and other various benefits, including equity awards, retirement and termination benefits.

In the event of termination without cause or if an executive officer terminates employment for good reason, the executive officer is entitled to receive a payment in the amount of three times the sum of his highest base salary during the previous two years of employment immediately preceding the termination date and his highest bonus received during the same two year period. The executive officer is also entitled to (i) vesting of any unvested equity compensation, (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of a pro rata bonus amount. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated.

In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and to provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

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Derivative Contracts. We are exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. We have had no counterparty default losses.

8. STOCK-BASED COMPENSATION

We maintain equity compensation plans for officers, certain key employees and non-employee directors. In accordance with the plans, awards may be issued in the form of stock options, stock appreciation rights and restricted stock. Through the date of this report, we have not issued any stock appreciation rights.

The following table provides a summary of the impact of our stock based compensation plans on the results of operations for the periods presented.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (in thousands) | | | |
| Total stock-based compensation expense (1) | $ 2,293 | $ 628 | $ 5,239 | $ 1,652 |
| Income tax benefit | (875) | (242) | (1,999) | (637) |
| Net income impact | $ 1,418 | $ 386 | $ 3,240 | $ 1,015 |

(1) Nine month activity includes $1.1 million related to the separation agreement with our former president. Three and nine month activity includes $1.1 million related to the retirement agreement with our former chief executive officer.

Stock Option Awards. We have granted stock options pursuant to various stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. There were no stock options awarded for the nine months ended September 30, 2008 and 2007.

The following table provides a summary of our stock option award activity for the nine months ended September 30, 2008:

| | Number of Shares Underlying Options | Weighted Average Exercise Price Per Share | Weighted Average Remaining Contractual Term (in years) | Aggregate Intrinsic Value (in millions) |
|---|---|---|---|---|
| Outstanding at December 31, 2007 | 51,567 | $ 33.55 | 6.4 | $ 1.3 |
| Exercised | (19,699) | 30.66 | - | 0.6 |
| Forfeited | (7,517) | 44.95 | - | - |
| Outstanding at September 30, 2008 | 24,351 | 32.36 | 5.5 | 0.3 |

| | | | | |
|---|---|---|---|---|
| Vested and expected to vest at September 30, 2008 | 24,351 | 32.36 | 5.5 | 0.3 |
| | | | | |
| Exercisable at September 30, 2008 | 16,122 | 27.01 | 4.5 | 0.3 |

Total unrecognized stock-based compensation cost related to stock options expected to vest was $0.1 million as of September 30, 2008. This cost is expected to be recognized over a weighted average period of 1.7 years. Pursuant to an agreement with our former chief executive officer, we vested options to purchase 5,870 common shares with a weighted average exercise price of $41.53. These options would not have vested pursuant to the original terms of the awards. Accordingly, the awards were revalued using a Monte Carlo pricing model and the following assumptions: expected term - one month; risk free interest rate - 1.63%; and volatility - 43%. We recognized $0.1 million in related stock based compensation expense during the quarter ended September 30, 2008.

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Restricted Stock Awards

We began issuing shares of restricted common stock to employees in 2004 and to non-employee directors in 2005. Vesting conditions for our restricted stock awards are either time-based or market-based.

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, generally over four years, and five years in connection with succession related grants to executive officers in March 2008. Time-based awards for non-employee directors generally vest on July 1st of the year following the date of the grant.

The following table sets forth the changes in non-vested time-based awards for the nine months ended September 30, 2008:

| | Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested at December 31, 2007 | 171,845 | $ 44.38 |
| Granted | 107,729 | 66.35 |
| Vested | (70,896) | 43.50 |
| Forfeited | (9,444) | 41.07 |
| Non-vested at September 30, 2008 | 199,234 | 56.20 |

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized as of September 30, 2008, is $9.3 million. This cost is expected to be recognized over a weighted-average period of 2.9 years. Pursuant to an agreement with our former chief executive officer, and the modification of his existing awards, we recognized an additional $0.3 million in stock based compensation expense during the quarter ended September 30, 2008, for shares not expected to vest in previous periods.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years. The market-based shares vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. All compensation cost related to the market based-awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

The weighted average grant date fair value of each market-based share, including each share modified pursuant to an agreement with our former chief executive officer, was computed using the Monte Carlo pricing model and the following weighted average assumptions:

| | Nine Months Ended September 30, 2008 | 2007 |
|---|---|---|
| Expected term of award | 3 years | 3 years |
| Risk-free interest rate | 2.4% | 4.7% |
| Volatility | 47.0% | 44.0% |
| Weigthed average grant date fair value | $42.44 | $36.07 |

The following table sets forth the changes in non-vested market-based awards for the nine months ended September 30, 2008:

| | Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested at December 31, 2007 | 31,972 | $ 36.07 |
| Granted | 48,405 | 45.15 |
| Vested | (3,078) | 52.00 |
| Forfeited | (4,616) | 36.07 |
| Non-vested at September 30, 2008 | 72,683 | 41.62 |

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The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized as of September 30, 2008, is $1.8 million. This cost is expected to be recognized over a weighted-average period of two years. Pursuant to an agreement with our former chief executive officer, and the modification of his existing awards, we recognized an additional $0.8 million in stock based compensation expense during the quarter ended September 30, 2008, for shares not expected to vest in previous periods.

Common and Preferred stock

Effective July 17, 2008, pursuant to shareholder approval, we amended and restated our Articles of Incorporation to: (1) increase the number of the Company's authorized shares of common stock, par value $0.01, from 50,000,000 shares to 100,000,000 shares, and (2) authorize 50,000,000 shares of Company preferred stock, par value $0.01, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by our Board of Directors from time to time. As of September 30, 2008, no preferred stock had been issued.

## 9. INCOME TAXES

We evaluate our estimated annual effective income tax rate on a quarterly basis based on current and forecasted business results and enacted tax laws. The estimated annual effective tax rate is adjusted quarterly based upon actual results and updated operating forecasts. Tax expenses or tax benefits unrelated to current year ordinary income or loss are recognized entirely in the period identified as discrete items of tax. The quarterly income tax provision is comprised of tax on ordinary income or tax benefit on ordinary loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

Our effective tax rate, before the effect of discrete items, was 37.1% for the first nine months of 2008 compared to 37.7% for the same prior year period. The decrease in the 2008 effective tax rate is primarily due to a decrease in the effective state rate from 3.5% in the prior year period to 3% for the current year period. Our effective tax rate, after the effect of discrete items, is 34% due to a net $3.4 million discrete tax benefit for discrete items of tax recognized in the current nine month period. Approximately $2.8 million of the current year discrete tax benefit is related to the implementation of state tax strategies. These strategies impacted previous tax filing positions taken in 2004 through 2007.

In conjunction with the implementation of our state tax strategies, taking into consideration changes in our state apportionment factors, we reevaluated the effective rate used to record our deferred state taxes. The rate used to record our deferred taxes represents the rate we estimate will be in effect when the temporary differences giving rise to deferred taxes reverse. This analysis resulted in a $1 million reduction in our deferred taxes included in the above mentioned net discrete deferred tax benefit.

As of September 30, 2008, we had a gross liability for uncertain tax benefits of $1.6 million, of which $0.5 million was recorded in the current nine month period. If recognized, $1.3 million of this liability would affect our effective tax rate. This liability is reflected in federal and state income taxes payable in our condensed consolidated balance sheet. The increase in the provision recorded in the current period is related to an uncertain tax benefit claimed on the 2007 tax return and currently expected to be claimed on the 2008 tax return. The Internal Revenue Service ("IRS") has begun its examination of our 2005 and 2006 tax years, and we currently expect this examination to be completed within one year. Therefore, we expect the liability for uncertain tax benefits to decrease during the next twelve month period as items are either resolved without change or converted to amounts due to the IRS.

As of the date of this filing, we are current with our income tax filings in all applicable state jurisdictions and currently have no state income tax returns in the process of examination. Administrative reviews of our West Virginia and Colorado amended tax returns, filed to implement the state tax strategies noted above, are pending.

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## 10. EARNINGS PER SHARE

A reconciliation of basic and diluted earnings per common share is as follows:

| | Three Months Ended September 30, 2008 | Three Months Ended September 30, 2007 | Nine Months Ended September 30, 2008 | Nine Months Ended September 30, 2007 |
|---|---|---|---|---|
| | (in thousands, except per share data) | | | |
| Weighted average common shares outstanding | 14,767 | 14,757 | 14,749 | 14,739 |
| Dilutive effect of share-based compensation: (1) | | | | |
| Unamortized portion of restricted stock | 27 | 35 | 64 | 41 |
| Stock options | 35 | 30 | 39 | 60 |
| Non employee director deferred compensation | 6 | 5 | 6 | 5 |
| Weighted average common and common equivalent shares outstanding | 14,835 | 14,827 | 14,858 | 14,845 |
| | | | | |
| Net income | $ 126,896 | $ 4,459 | $ 72,256 | $ 25,011 |
| Basic earnings per common share | $ 8.59 | $ 0.30 | $ 4.90 | $ 1.70 |
| Diluted earnings per common share | $ 8.55 | $ 0.30 | $ 4.86 | $ 1.68 |

(1) For the three and nine months ended September 30, 2008, 133 and 74 average common share equivalents, respectively, related to unvested restricted stock were excluded from the computation of diluted net earnings per share as their effect was anti-dilutive. There were no common share equivalents for options or non employee director deferred compensation excluded from the computation of diluted net earnings per share for the current three and nine months periods. For the three and nine months ended September 30, 2007, 25, 24, and zero and 10, zero, and zero average common share equivalents, respectively, related to unvested restricted stock, stock options and shares related to non employee director deferred compensation, were excluded from the computation of diluted net earnings per share as their effect was anti-dilutive.

## 11. BUSINESS SEGMENTS

Our operating activities are divided into four major segments: oil and gas sales, natural gas marketing, oil and gas well drilling operations, and well operations and pipeline income. We drill oil and natural gas wells for our own benefit and for Company-sponsored drilling partnerships, retaining an interest in each well we drill. We own an interest in approximately 4,600 wells from which we sell our oil and gas production from our working interests in the wells. We charge Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. All material intercompany accounts and transactions between segments have been eliminated. Segment information for the three months and nine months ended September 30, 2008 and 2007 is presented below.

| | Three Months Ended September 30, 2008 | Three Months Ended September 30, 2007 | Nine Months Ended September 30, 2008 | Nine Months Ended September 30, 2007 |
|---|---|---|---|---|
| | (in thousands) | | | |
| Revenues: | | | | |
| Oil and gas sales (1) | $ 268,824 | $ 50,782 | $ 290,911 | $ 122,141 |

| | | | | |
|---|---|---|---|---|
| Natural gas marketing | 53,372 | 19,934 | 107,638 | 71,845 |
| Oil and gas well drilling operations | 1,232 | 1,573 | 7,202 | 7,342 |
| Well operations and pipeline income | 3,356 | 2,092 | 8,146 | 6,682 |
| Unallocated amounts | 20 | 1,894 | 57 | 2,122 |
| Total | $ 326,804 | $ 76,275 | $ 413,954 | $ 210,132 |
| | | | | |
| Segment income (loss) before income taxes: | | | | |
| Oil and gas sales (1)(2) | $ 210,091 | $ 14,367 | $ 146,965 | $ 28,727 |
| Natural gas marketing | (918) | 333 | 1,286 | 2,357 |
| Oil and gas well drilling operations | 731 | 824 | 6,105 | 5,783 |
| Well operations and pipeline income (3) | 1,659 | 486 | 2,980 | 1,900 |
| Unallocated amounts (4) | (16,434) | (8,225) | (47,858) | 1,755 |
| Total | $ 195,129 | $ 7,785 | $ 109,478 | $ 40,522 |

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(1) Represents oil and gas sales revenue and oil and gas price risk management gain, net. For the nine months ended September 30, 2008, oil and gas sales revenue includes a $4.0 million charge related to a royalty litigation provision, see Note 7.
(2) Includes exploration expense and DD&A expense in the amount of $27.6 million and $68.7 million for the three and nine months ended September 30, 2008, respectively, and $19.3 million and $48.2 million for the three and nine months ended September 30, 2007, respectively.
(3) Includes DD&A expense in the amount of $0.5 million and $1.3 million for the three and nine months ended September 30, 2008, and $0.7 million and $1.9 million for the three and nine months ended September 30, 2007, respectively.
(4) Includes general and administrative expense, gain on sale of leaseholds, interest income and expense, and DD&A expense in the amount of $0.6 million and $1.8 million for the three and nine months ended September 30, 2008, and $0.3 million and $0.8 million for the three and nine months ended September 30, 2007, respectively.

| | September 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in thousands) | |
| Segment assets: | | |
| Oil and gas sales | $ 1,058,028 | $ 862,237 |
| Natural gas marketing | 47,426 | 40,269 |
| Oil and gas well drilling operations | 10,377 | 4,959 |
| Well operations and pipeline income | 55,685 | 26,156 |
| Unallocated amounts | 107,485 | 116,858 |
| Total | $ 1,279,001 | $ 1,050,479 |

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

### NOTE REGARDING FORWARD-LOOKING STATEMENTS

This periodic report on Form 10-Q contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are our estimates of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in successfully drilling productive wells and in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, our ability to sell our produced natural gas and oil and the prices we receive for production, our ability to control the costs of our operations, our ability to comply with changes in federal, state, local, and other laws and regulations, including environmental policies, the significant fluctuations in the oil and gas price environment and our ability to meet our price risk management objectives, and the operating hazards inherent to the oil and natural gas business. In particular, careful consideration should be given to cautionary statements made in this Form 10-Q, our Annual Report on Form 10-K for the year ended December 31, 2007, and our other SEC filings and public disclosures. We undertake no duty to update or revise these forward-looking statements.

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Overview

The following table sets forth selected information regarding our results of operations, including production volumes, oil and gas sales, average sales prices received, average sales price including realized derivative gains and losses, average lifting cost, other operating income and expenses for the three and nine months ended September 30, 2008, or the current three and nine month periods, and the three and nine months ended September 30, 2007, or the prior three and nine month periods.

| | Three Months Ended September 30, | | | Nine Months Ended September | | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | Percentage Change | 2008 | 2007 | Perce Cha |
| ction | | | | | | |
| Bbls) | 322,133 | 234,735 | 37.2% | 834,183 | 666,752 | 2 |
| al gas (Mcf) | 8,239,005 | 6,312,177 | 30.5% | 22,443,011 | 15,489,188 | 4 |
| al gas equivalent (Mcfe) (1) | 10,171,803 | 7,720,587 | 31.7% | 27,448,109 | 19,489,700 | 4 |
| nd Gas Sales (in thousands) | | | | | | |
| les | $ 34,804 | $ 14,945 | 132.9% | $ 87,158 | $ 37,192 | 13 |
| ales | 64,448 | 29,492 | 118.5% | 182,484 | 80,507 | 12 |
| ty litigation provision | 170 | - | 100.0% | (4,025) | - | 10 |
| oil and gas sales | $ 99,422 | $ 44,437 | 123.7% | $ 265,617 | $ 117,699 | 12 |
| zed Gain (Loss) on Derivatives, net (in thousands) | | | | | | |
| erivatives - realized gain (loss) | $ (4,157) | $ (54) | * | $ (9,857) | $ (159) | |
| al gas derivatives - realized gain (loss) | 1,405 | 2,545 | -44.8% | (10,660) | 3,257 | |
| realized gain (loss) on derivatives, net | $ (2,752) | $ 2,491 | -210.5% | $ (20,517) | $ 3,098 | |
| ge Sales Price | | | | | | |
| er Bbl) (2) | $ 108.04 | $ 63.67 | 69.7% | $ 104.48 | $ 55.78 | 8 |
| al gas (per Mcf) (2) | $ 7.82 | $ 4.67 | 67.5% | $ 8.13 | $ 5.20 | 5 |
| al gas equivalent (per Mcfe) | $ 9.76 | $ 5.76 | 69.4% | $ 9.82 | $ 6.04 | 6 |
| ge Sales Price (including realized gain (loss) on derivatives) | | | | | | |
| er Bbl) | $ 95.14 | $ 63.44 | 50.0% | $ 92.67 | $ 55.54 | 6 |
| al gas (per Mcf) | $ 7.99 | $ 5.08 | 57.3% | $ 7.66 | $ 5.41 | 4 |
| al gas equivalent (per Mcfe) | $ 9.49 | $ 6.08 | 56.1% | $ 9.08 | $ 6.20 | 4 |
| ge Lifting Cost per Mcfe (3) | $ 0.94 | $ 0.86 | 9.3% | $ 1.07 | $ 0.89 | 2 |
| Operating Income(4) (in thousands) | | | | | | |
| al gas marketing activities | $ (1,000) | $ 124 | * | $ 1,028 | $ 1,743 | -4 |
| nd gas well drilling operations | $ 731 | $ 824 | -11.3% | $ 6,105 | $ 5,783 | |
| and Expenses (in thousands) | | | | | | |
| ration expense | $ 10,212 | $ 5,337 | 91.3% | $ 17,962 | $ 14,795 | 2 |
| ral and administrative expense | $ 8,106 | $ 7,513 | 7.9% | $ 27,160 | $ 21,823 | 2 |
| eciation, depletion and amortization | $ 28,645 | $ 20,354 | 40.7% | $ 71,881 | $ 50,857 | 4 |
| st Expense (in thousands) | $ (7,817) | $ (2,544) | 207.3% | $ (19,143) | $ (4,825) | |

resents percentages in excess of 250%

(1) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one barrel of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.
(2) We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility of our natural gas and oil sales. This amount excludes realized and unrealized gains and losses on commodity based derivative instruments.
(3) Average lifting costs represent oil and gas operating expenses, excluding production taxes. See Oil and Gas Production and Well Operations Costs discussion below.
(4) Includes revenues and operating expenses.

We are an independent energy company engaged in the exploration, development, production and marketing of oil and natural gas. Since we began oil and gas operations in 1969, we have grown through drilling and development activities, acquisitions of producing natural gas and oil wells and the expansion of our natural gas marketing activities.

We began 2008 with interests in approximately 4,354 gross, 2,934 net, wells located in the Rocky Mountain Region and the Appalachian and Michigan Basins. Based on current market conditions, our current plans are to drill approximately 375 gross, 341 net, wells in 2008, representing a decrease of 72 gross wells from our previous plans. We also plan to recomplete approximately 100 Wattenberg Field wells (Colorado) and 30 wells in the Appalachian Basin during 2008. For the current nine month period, we drilled 298 gross, 254 net, wells compared to 264 gross, 220.4 net, wells during the same prior year period, an increase in gross drilling activity of 13%. Recompletions for the current nine month period consisted of 87 wells in the Wattenberg Field and 18 wells in the Appalachian Basin.

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Our production for the current nine month period was 27.4 Bcfe, averaging 100.2 MMcfe per day, a 40.3% increase over 71.4 MMcfe per day produced during the prior nine month period. Weighted average prices (excluding realized gains or losses on derivatives) were $9.82 per Mcfe for the current nine month period compared to $6.04 for the prior nine month period. Increased production and commodity prices contributed $78.2 million and $73.7 million, respectively, to the total increase of $151.9 million in oil and gas sales revenue for the current nine month period, exclusive of royalty litigation provision.

During the six month period ended June 30, 2008, oil prices increased rapidly to record highs, while natural gas prices increased sharply from December 31, 2007. Subsequent to June 30, 2008, oil and natural gas prices have declined sharply to levels below those at December 31, 2007. The decline in prices during the third quarter of 2008 has resulted in a $172.2 million unrealized gain on derivatives for the quarter ended September 30, 2008. This quarterly unrealized gain has reversed our June 30, 2008, unrealized loss of $126.4 million to an unrealized gain of $45.8 million for the nine months ended September 30, 2008. See Oil and Gas Price Risk Management, net discussion below.

The average NYMEX and CIG prices for the next 24 months (forward curve) from the respective dates below are as follows:

| | | | 2008 | |
|---|---|---|---|---|
| Commodity | Index | June 30, | September 30, | October 30, |