PETROLEUM DEVELOPMENT CORP
Form 10-Q
August 08, 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 June 30, 2008

OR

¨ 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 ¨

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 ¨	Accelerated filer x
Non-accelerated filer ¨	Smaller reporting company ¨

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: 14,851,436 shares of the Company's Common Stock ($.01 par value) were outstanding as of August 1, 2008.

PETROLEUM DEVELOPMENT CORPORATION

INDEX

Index

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

Petroleum Development Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	June 30, 2008	December 31, 2007*
Assets		
Current assets:		
Cash and cash equivalents	$ 33,260	$ 84,751
Accounts receivable, net	78,019	60,024
Accounts receivable - affiliates	72,731	11,537
Fair value of derivatives	14,285	4,817
Other current assets	91,733	30,664
Total current assets	290,028	191,793
Properties and equipment, net	918,126	845,864
Other assets	35,532	12,822
Total assets	$ 1,243,686	$ 1,050,479
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 106,861	$ 88,502
Accounts payable - affiliates	1,320	3,828
Fair value of derivatives - current	135,561	6,291
Advances for future drilling contracts	15,084	68,417
Funds held for future distribution	69,287	39,823
Other accrued expenses	41,164	35,144
Total current liabilities	369,277	242,005
Long-term debt	254,000	235,000
Deferred income taxes	166,157	136,490
Fair value of derivatives - long term	65,637	93
Other liabilities	47,866	40,606
Total liabilities	902,937	654,194
Commitments and contingencies		
Minority interest in consolidated limited liability company	727	759
Total shareholders' equity	340,022	395,526
Total liabilities and shareholders' equity	$ 1,243,686	$ 1,050,479

*Derived from audited 2007 balance sheet.

See accompanying notes to condensed consolidated financial statements.

Index

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Revenues:				
Oil and gas sales	$ 94,549	$ 39,246	$ 166,195	$ 73,262
Sales from natural gas marketing activities	30,941	29,924	54,266	51,911
Oil and gas well drilling operations	2,887	1,739	5,970	5,769
Well operations and pipeline income	2,438	1,292	4,790	4,590
Oil and gas price risk management gain (loss), net	(101,798)	3,742	(144,108)	(1,903)
Other	34	2	37	228
Total revenues	29,051	75,945	87,150	133,857
Costs and expenses:				
Oil and gas production and well operations cost	20,815	11,628	38,947	20,663
Cost of natural gas marketing activities	30,117	28,780	52,238	50,292
Cost of oil and gas well drilling operations	518	246	596	810
Exploration expense	3,467	6,780	7,750	9,458
General and administrative expense	9,231	6,886	19,054	14,310
Depreciation, depletion and amortization	22,105	17,429	43,236	30,503
Total costs and expenses	86,253	71,749	161,821	126,036
Gain on sale of leaseholds	-	25,600	-	25,600
Income (loss) from operations	(57,202)	29,796	(74,671)	33,421
Interest income	75	454	346	1,597
Interest expense	(6,394)	(1,450)	(11,326)	(2,281)
Income (loss) before income taxes	(63,521)	28,800	(85,651)	32,737
Provision (benefit) for income taxes	(22,809)	10,749	(31,011)	12,185
Net income (loss)	$ (40,712)	$ 18,051	$ (54,640)	$ 20,552
Earnings (loss) per share				
Basic	$ (2.76)	$ 1.22	$ (3.71)	$ 1.40
Diluted	$ (2.76)	$ 1.21	$ (3.71)	$ 1.38
Weighted average common shares outstanding				
Basic	14,742	14,740	14,740	14,730
Diluted	14,742	14,860	14,740	14,851

See accompanying notes to condensed consolidated financial statements.

Index

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

	Six Months Ended June 30,	
	2008	2007
Cash flows from operating activities:		
Net income (loss)	$ (54,640)	$ 20,552
Adjustments to net income (loss) to reconcile to cash provided by (used in) operating activities:		
Deferred income taxes	(20,156)	5,707
Depreciation, depletion and amortization	43,236	30,503
Amortization of debt issuance costs	588	-
Accretion of asset retirement obligation	609	469
Exploratory dry hole costs	1,100	194
Gain from sale of leaseholds	-	(25,600)
Expired and abandoned leases	942	1,193
Unrealized loss on derivative transactions	125,656	2,523
Other	2,260	1,024
Changes in current assets and liabilities:		
Increase in current assets and current liabilities	(32,583)	(109,293)
Increase (decrease) in other assets and liabilities	718	(3,657)
Net cash provided by (used in) operating activities	67,730	(76,385)
Cash flows from investing activities:		
Capital expenditures	(126,786)	(73,122)
Acquisitions	-	(201,594)
Decrease in restricted cash for property acquisition	-	191,155
Other	177	385
Net cash used in investing activities	(126,609)	(83,176)
Cash flows from financing activities:		
Proceeds from credit facility	173,000	162,000
Proceeds from senior notes	200,101	-
Repayment of credit facility	(357,000)	(175,000)
Payment of debt costs	(4,934)	-
Proceeds from exercise of stock options	367	164
Excess tax benefits from stock based compensation	532	-
Purchase of treasury stock	(4,678)	(343)
Net cash provided by (used in) financing activities	7,388	(13,179)
Net decrease in cash and cash equivalents	(51,491)	(172,740)
Cash and cash equivalents, beginning of period	84,751	194,326
Cash and cash equivalents, end of period	$ 33,260	$ 21,586

Supplemental disclosure of cash flow information of cash payments for:		
Interest	$ 3,719	$ 3,915
Income taxes	7,244	42,447
Supplemental schedule of non-cash investing and financing activities:		
Change in deferred tax liability resulting from reallocation 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	(5,874)	27,335
Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	463	5,081

See accompanying notes to condensed consolidated financial statements.

4

Index

Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
June 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 six months ended June 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 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 June 30, 2008, we had not elected, nor do we intend, to measure additional financial assets and liabilities at fair value.

Index

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.

Index

3. PROPERTIES AND EQUIPMENT

	June 30, 2008	December 31, 2007
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	$ 1,057,460	$ 953,904
Unproved	42,607	41,023
Total oil and gas properties	1,100,067	994,927
Pipelines and related facilities	26,935	22,408
Transportation and other equipment	29,548	23,669
Land and buildings	14,184	11,303
Construction in progress (1)	-	2,929
	1,170,734	1,055,236
Accumulated depreciation, depletion and amortization ("DD&A")	(252,608)	(209,372)
	$ 918,126	$ 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	8,067	10
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(2,238)	(1)
Capitalized exploratory well costs charged to expense	(1,100)	(1)
Ending balance at June 30, 2008	$ 7,029	11

As of June 30, 2008, none of the eleven 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.

Index

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 June 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 virtually eliminate 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 derivative instruments continue to be effective in achieving the risk management objectives for which they were intended, although they are currently below market due to the general rise in energy prices during 2008.

The following table summarizes the estimated fair value of our oil and natural gas derivative positions as of June 30, 2008.

	Open Derivative Positions as of June 30, 2008		
	Short-Term	Long-Term	Total
	(in thousands)		
Oil and gas sales activities assets (liabilities): (1)			
Natural gas floors	$ 903	$ 2,888	$ 3,791
Natural gas ceilings	(6,300)	(5,455)	(11,755)
Natural gas swaps	(71,688)	(7,168)	(78,856)
Oil swaps	(45,192)	(50,073)	(95,265)
Total	$ (122,277)	$ (59,808)	$ (182,085)
Natural gas marketing activities assets (liabilities): (2)			
Natural gas floors	$ 30	$ -	$ 30
Natural gas ceilings	(248)	-	(248)
Natural gas swaps	(12,107)	(2,941)	(15,048)
Physical purchases	13,352	3,277	16,629
Physical sales	(26)	-	(26)
Total	$ 1,001	$ 336	$ 1,337

(1) The maximum term for the derivative positions is 45 months.
(2) The maximum term for the derivative positions is 42 months.

In addition to including the gross assets and liabilities 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 on behalf of our affiliate partnerships as the managing general partner. Our condensed consolidated balance sheets include the fair value of derivatives and a corresponding net receivable from the partnerships of $55.2 million at June 30, 2008, and $1.5 million at December 31, 2007.

Index

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

	June 30, 2008	December 31, 2007
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	$ 14,285	$ 4,817
Other assets - long-term asset	6,165	193
	20,450	5,010
Fair value of derivatives - current liability	135,561	6,291
Fair value of derivatives - long term	65,637	93
	201,198	6,384
Net fair value of commodity based derivatives	$ (180,748)	$ (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 June 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)	$ (15,354)	$ (86,444)	$ 27	$ 3,715
Sales from natural gas marketing activities	(2,283)	(9,053)	231	2,030
Cost of natural gas marketing activities	51	9,174	(49)	(1,631)

	Six Months Ended June 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)	$ (17,765)	$ (126,343)	$ 608	$ (2,511)
Sales from natural gas marketing activities	(1,797)	(16,691)	1,327	(1,268)
Cost of natural gas marketing activities	117	17,378	(223)	1,256

(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:

Index

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.

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. 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 June 30, 2008:

	Level 1	Level 3	Total
	(in thousands)		
Assets	$ 30	$ 20,420	$ 20,450
Liabilities	(39,325)	(161,873)	(201,198)
	$ (39,295)	$ (141,453)	$ (180,748)

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

	June 30, 2008	
	Three Months Ended	Six Months Ended
	(in thousands)	
Fair value, beginning of period (1)	$ (41,798)	$ (2,368)
Total realized and unrealized gains or (losses):		
Included in oil and gas price risk management gain (loss), net	(42,539)	(43,521)
Included in sales from natural gas marketing activities	(35)	(57)
Included in cost of natural gas marketing activities	2,638	2,633
Purchases, issuances and settlements, net	(59,719)	(98,140)
Fair value, end of period	$ (141,453)	$ (141,453)

Total gains (losses) attributable to the change in unrealized (loss), relating to assets still held as of June 30, 2008:				
Included in oil and gas price risk management gain (loss), net	$	(39,937)	$	(40,946)
Total	$	(39,937)	$	(40,946)

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

10

Index

6. LONG-TERM DEBT

Long-term debt consists of the following:

	June 30, 2008	December 31, 2007
	(in thousands)	
Credit facility	$ 51,000	$ 235,000
12% Senior notes due 2018	203,000	-
Total long-term debt	$ 254,000	$ 235,000

Credit facility

We have a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended, dated as of November 4, 2005, with an activated commitment of $234.1 million as of June 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; and The Royal Bank of Scotland, plc. The maximum allowable commitment under the current credit facility is $400 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 ..25% to .375% 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 ..375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%, 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 June 30, 2008, we had drawn $51 million from our credit facility compared to $235 million as of December 31, 2007. The borrowing rate on the outstanding balance was 4% as of June 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 June 30, 2008, and expect to remain in compliance throughout 2008.

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, commencing 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.

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 June 30, 2008, and expect to remain in compliance throughout 2008.

Index

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 June 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 50 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 June 30, 2008, we have drilled one well pursuant to 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 June 30, 2008, was approximately $9.7 million. We have adequate liquidity to meet this obligation. During the six months of 2008 and for 2007, we paid $3.3 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. As of June 30, 2008, we have an outstanding minimum commitment for $5.7 million and an outstanding maximum commitment for $21.2 million.

Index

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 the State of Colorado (the "Droegemueller Action"). The plaintiff seeks 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. The court approved a stay in proceedings until August 8, 2008 while the parties pursue mediation of the matter. Based on the mediation held on May 28, 2008, and subsequent negotiations, we have reserved $4.2 million for this potential liability in the second quarter of 2008, for a total reserve of $5.9 million. We consider the $4.2 million reserve as an additional royalty payment and therefore have recorded such amount as a reduction of oil and gas sales revenue in the current quarter. While we are unable to predict the ultimate outcome of this suit, we believe that after consideration of the reserve discussed above, the ultimate outcome of the proceedings will not have a material adverse effect on our financial condition or results of operations.

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 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.

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 June 30,				Six Months Ended June 30,			
	2008		2007		2008		2007	
	(in thousands)							
Total stock-based compensation expense (1)	$	1,154	$	541	$	2,946	$	1,024
Income tax benefit		(433)		(202)		(1,124)		(381)
Net income impact	$	721	$	339	$	1,822	$	643

(1) Six month activity includes $1.1 million related to the separation agreement with our former president.

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 six months ended June 30, 2008 and 2007.

13

Index

The following table provides a summary of our stock option award activity for the six months ended June 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	(8,829)	41.51		0.2
Outstanding at June 30, 2008	42,738	31.90	5.6	1.5
Vested and expected to vest at June 30, 2008	37,512	30.39	5.4	1.4
Exercisable at June 30, 2008	29,283	26.89	4.7	1.2

Total unrecognized stock-based compensation cost related to stock options expected to vest was $0.1 million as of June 30, 2008. This cost is expected to be recognized over a weighted average period of 1.3 years. As of June 30, 2008, stock-based compensation related to stock options not expected to vest and unamortized was $0.1 million.

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. 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 six months ended June 30, 2008:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2007	171,845	$ 44.38
Granted	93,704	69.15
Vested	(45,116)	46.20
Forfeited	(5,894)	42.82
Non-vested at June 30, 2008	214,539	54.37

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized as of June 30, 2008, is $9.2 million. This cost is expected to be recognized over a weighted-average period of 3.2 years. As of June 30, 2008, stock-based compensation related to time-based awards not expected to vest and unamortized was $0.6 million.

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.

Index

The weighted average grant date fair value of each market-based share was computed using the Monte Carlo pricing model and the following weighted average assumptions:

	Six Months Ended June 30, 2008	2007
Expected term of award	3 years	3 years
Risk-free interest rate	2.4%	4.7%
Volatility	47.0%	44.0%

The following table sets forth the changes in non-vested marked-based awards for the six months ended June 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 June 30, 2008	72,683	42.12

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized as of June 30, 2008, is $1.2 million. This cost is expected to be recognized over a weighted-average period of 2.5 years. As of June 30, 2008, stock-based compensation related to market-based awards not expected to vest and unamortized was $1.6 million.

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 33.7% for the first six months of 2008 compared to 37% for the same prior year period. The decrease in the 2008 effective tax rate is primarily due to a proportionately larger 2008 percentage depletion deduction. We also recorded $2.7 million of tax benefit for discrete tax items in the current three and six month periods. A total of $1.4 million of the benefit related to state tax strategies implemented in the current three month period. 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 reduction in our deferred taxes and was $1.3 million of the discrete deferred tax benefit in the current period.

As of June 30, 2008, we had a gross liability for uncertain tax benefits of $1.3 million, of which $.4 million was recorded in the current period. If recognized, $.8 million of this liability would affect our effective tax rate. This liability is reflected in other liabilities in our condensed consolidated balance sheet. The increase in the provision recorded in the current period is related to an uncertain tax benefit to be claimed on the 2007 and 2008 tax returns. 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 2008 as items are either resolved without change or converted to amounts due to the IRS.

Our Michigan Single Business Tax returns for the tax years 2002 through 2006 were recently examined by the Michigan Department of Treasury. No significant tax adjustments have been proposed and none are currently expected. We are current with our income tax filings in other state jurisdictions and currently have no other state income tax returns in the process of examination or administrative appeal.

Index

10. EARNINGS PER SHARE

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008		2007		2008		2007	
	(in thousands, except per share data)							
Weighted average common shares outstanding		14,742		14,740		14,740		14,730
Dilutive effect of share-based compensation: (1)								
Unamortized portion of restricted stock		-		69		-		65
Stock options		-		46		-		51
Non employee director deferred compensation		-		5		-		5
Weighted average common and common equivalent shares outstanding		14,742		14,860		14,740		14,851
Net income (loss)	$	(40,712)	$	18,051	$	(54,640)	$	20,552
Basic earnings (loss) per common share	$	(2.76)	$	1.22	$	(3.71)	$	1.40
Diluted earnings (loss) per common share	$	(2.76)	$	1.21	$	(3.71)	$	1.38

(1) For the three and six months ended June 30, 2008, 72, 37 and 6, and 78, 40, and 6 average common share equivalents related to unvested restricted stock, stock options and shares related to non employee director deferred compensation, respectively, were excluded from the computation of diluted net loss per share as their effect was anti-dilutive. For the three and six months ended June 30, 2007, there were no common share equivalents excluded from the computation of diluted net income per share.

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 natural gas wells for Company-sponsored drilling partnerships and retain an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. 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. All material intercompany accounts and transactions between segments have been eliminated. Segment information for the three months and six ended June 30, 2008 and 2007 is presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Revenues:				

Oil and gas sales (1)	$ (7,249)	$ 42,988	$ 22,087	$ 71,359
Natural gas marketing	30,941	29,924	54,266	51,911
Oil and gas well drilling operations	2,887	1,739	5,970	5,769
Well operations and pipeline income	2,438	1,292	4,790	4,590
Unallocated amounts	34	2	37	228
Total	$ 29,051	$ 75,945	$ 87,150	$ 133,857
Segment income (loss) before income taxes:				
Oil and gas sales (1)(2)	$ (51,132)	$ 8,521	$ (63,126)	$ 14,360
Natural gas marketing	872	1,345	2,204	2,024
Oil and gas well drilling operations	2,370	1,493	5,375	4,959
Well operations and pipeline income (3)	729	179	1,321	1,414
Unallocated amounts (4)	(16,360)	17,262	(31,425)	9,980
Total	$ (63,521)	$ 28,800	$ (85,651)	$ 32,737

(1) Represents oil and gas sales revenue and oil and gas price risk management gain (loss), net. For the three and six months ended June 30, 2008, oil and gas sales revenue includes a $4.2 million charge related to a royalty litigation provision, see Note 7.

Index

(2) Includes exploration expense and DD&A expense in the amount of $20.8 million and $41.1 million for three and six months ended June 30, 2008, respectively, and $16.6 million and $28.9 million for the three and six months ended June 30, 2007, respectively.
(3) Includes DD&A expense in the amount of $0.5 million and $0.9 million for three and six months ended June 30, 2008, and $0.6 million and $1.1 million for the three and six months ended June 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 $0.8 million and $1.3 million for three and six months ended June 30, 2008, and $0.2 million and $0.4 million for the three and six months ended June 30, 2007, respectively.

	June 30, 2008	December 31, 2007
	(in thousands)	
Segment assets:		
Oil & gas sales	$ 946,530	$ 862,237
Natural gas marketing	58,908	40,269
Oil and gas well drilling operations	10,394	4,959
Well operations and pipeline income	91,903	26,156
Unallocated amounts	135,951	116,858
Total	$ 1,243,686	$ 1,050,479

12. SUBSEQUENT EVENT

Effective July 15 and July 18, 2008, we entered into a Third and Fourth Amendment to the Credit Agreement, respectively. These amendments increased our Borrowing Base to $300 million. The following banks were also admitted as parties to the credit facility: Calyon New York Branch, Compass Bank, The Bank of Nova Scotia, and BMO Capital Markets Financing, Inc. As a result of the Third Amendment, fees were increased as follows: the maximum commitment fee increased from .25% to .375% per annum to .375% to .50% per annum of the unused portion of the activated credit facility; 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.

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 June 30, 2008, no preferred stock had been issued.

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.

Index

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 six months ended June 30, 2008, or the current three and six month periods, and the three and six months ended June 30, 2007, or the prior three and six month periods.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2008	2007	Percentage Change	2008	2007	Percentage Change
Production						
Oil (Bbls)	256,598	232,478	10.4%	512,050	432,017	18.5%
Natural gas (Mcf)	7,257,184	5,041,058	44.0%	14,204,006	9,177,011	54.8%
Natural gas equivalent (Mcfe) (1)	8,796,772	6,435,926	36.7%	17,276,306	11,769,113	46.8%
Oil and Gas Sales (in thousands)						
Oil sales	$ 31,627	$ 13,255	138.6%	$ 52,354	$ 22,247	135.3%
Gas sales	67,117	25,991	158.2%	118,036	51,015	131.4%
Royalty litigation provision	(4,195)	-	100.0%	(4,195)	-	100.0%
Total oil and gas sales	$ 94,549	$ 39,246	140.9%	$ 166,195	$ 73,262	126.9%
Realized Gain (Loss) on Derivatives, net (in thousands)						
Oil derivatives - realized gain (loss)	$ (4,394)	$ (53)	*	$ (5,700)	$ (105)	*
Natural gas derivatives - realized gain (loss)	(10,960)	80	*	(12,065)	713	*
Total realized gain (loss) on derivatives, net	$ (15,354)	$ 27	*	$ (17,765)	$ 608	*
Average Sales Price						
Oil (per Bbl) (2)	$ 123.26	$ 57.02	116.2%	$ 102.24	$ 51.50	98.5%
Natural gas (per Mcf) (2)	$ 9.25	$ 5.16	79.4%	$ 8.31	$ 5.56	49.5%
Natural gas equivalent (per Mcfe)	$ 11.23	$ 6.10	84.1%	$ 9.86	$ 6.22	58.4%
Average Sales Price (including realized gain (loss) on derivatives)						
Oil (per Bbl)	$ 106.13	$ 56.79	86.9%	$ 91.11	$ 51.25	77.8%
Natural gas (per Mcf)	$ 7.74	$ 5.17	49.7%	$ 7.46	$ 5.64	32.3%
Natural gas equivalent (per Mcfe)	$ 9.48	$ 6.10	55.3%	$ 8.83	$ 6.28	40.8%
Average Lifting Cost per Mcfe (3)	$ 1.13	$ 1.06	6.6%	$ 1.13	$ 0.90	25.6%

Other Operating Income(4) (in thousands)									
Natural gas marketing activities	$	824	$	1,144	-28.0%	$	2,028	$	1,619	25.3%
Oil and gas well drilling operations	$	2,369	$	1,493	58.7%	$	5,374	$	4,959	8.4%
Costs and Expenses (in thousands)										
Exploration expense	$	3,467	$	6,780	-48.9%	$	7,750	$	9,458	-18.1%
General and administrative expense	$	9,231	$	6,886	34.1%	$	19,054	$	14,310	33.2%
Depreciation, depletion and amortization	$	22,105	$	17,429	26.8%	$	43,236	$	30,503	41.7%
Interest Expense (in thousands)	$	(6,394)	$	(1,450)	*	$	(11,326)	$	(2,281)	*

*Represents 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 an 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. We plan to drill approximately 447 gross, 412 net, wells in 2008. We also plan to recomplete approximately 100 Wattenberg Field wells (Colorado) and 30 wells in the Appalachian Basin during 2008. For the current six month period, we drilled 202 gross, 160.4 net, wells compared to 169 gross, 139.6 net, wells during the same prior year period, an increase in gross drilling activity of 19.5%. Recompletions for the current six month period consisted of 62 wells in the Wattenberg Field and 10 wells in the Appalachian Basin.

Our production for the current six month period was 17.3 Bcfe, averaging 94.9 MMcfe per day, a 46% increase over 65 MMcfe per day produced during the prior six month period. Weighted average prices (excluding realized gains or losses on derivatives) were $9.86 per Mcfe for the current six month period compared to $6.22 for the prior six month period. Increased production and commodity prices contributed $34.3 million and $62.8 million, respectively, to the total increase of $97.1 million in oil and gas sales revenue for the current six month period.

Index

During the current six month period, we realized losses on derivatives related to our oil and gas sales activities totaling $17.8 million due to significant increases in oil and natural gas prices. Rapid increases during the first and second quarters of 2008 to record high oil prices and sharp increases in natural gas prices along with our increased use of fixed price swaps resulted in both realized and unrealized losses on oil and gas derivative activity. See Oil and Gas Price Risk Management, Net discussion below.

The rapid increases in oil prices in the current six month period to record highs and sharp increases in natural gas prices from December 31, 2007, along with our increased use of fixed price swaps resulted in significant unrealized losses in oil and gas price risk management, net. The $126.3 million in unrealized losses for the current six month period is the fair value of the derivative positions as of June 30, 2008, less the related unrealized amounts recorded in prior periods. An unrealized loss is a non-cash item and there will be further gains or losses as prices increase or decrease until the positions are closed. While the required accounting treatment for derivatives that do not qualify for hedge accounting treatment under SFAS No. 133 results in significant swings in value and resulting gains and losses for reporting purposes over the life of the derivatives, the combination of the settled derivative contracts and the revenue received from the oil and gas sales at delivery are expected to result in a more predictable cash flow stream than would the sales contracts without the associated derivatives. The prices of both oil and natural gas have declined significantly since June 30, 2008, and if the prices remain at current levels or continue to decline, we expect to experience unrealized derivative gains for the third quarter of 2008.

While we benefit significantly from rising energy prices in our oil and gas sales, the rising energy prices bring about inflationary factors that affect our costs and expenses. The increase in energy prices has affected demand for drilling and completion services, land acquisitions and the cost of experienced industry personnel. We expect this inflationary trend to continue as energy prices rise or remain at historically high levels. We consume great quantities of fuel in the use of drilling rigs, service rigs, vehicles used for hauling materials, such as surface casing, tubular goods and water, as well as, vehicles used for well tending and general operations.

Results of Operations

General

Total revenues for oil and natural gas sales activities for the current three and six month periods, excluding a royalty litigation provision of $4.2 million, increased 152% and 133%, respectively, over the same prior year periods. This increase was driven by oil and gas production which increased for the current three and six month periods by 37% and 47%, respectively. These increases were more than offset by the significant increase in realized and unrealized losses related to our oil and gas derivative instruments which resulted in a loss for both periods.

For the current three month period, we recorded a $4.2 million royalty litigation provision. We consider this provision as an additional royalty payment and therefore have recorded such amount as a reduction of oil and gas sales revenue. See Note 7 of the accompanying condensed consolidated financial statements for a discussion of the Droegemueller Action royalty litigation provision.

Oil and Natural Gas Production and Sales Activity by Area

	Three Months Ended June 30,			Six Months Ended June 30,		
	2008	2007	Percentage Change	2008	2007	Percentage Change
Production						
Oil (Bbls)						
Appalachian Basin	1,542	1,840	-16.2%	2,638	3,214	-17.9%

Michigan Basin	1,008	1,167	-13.6%	1,831	1,982	-7.6%
Rocky Mountain Region	254,048	229,471	10.7%	507,581	426,821	18.9%
Total	256,598	232,478	10.4%	512,050	432,017	18.5%
Natural gas (Mcf)						
Appalachian Basin	996,729	675,591	47.5%	1,964,349	1,284,988	52.9%
Michigan Basin	386,906	420,390	-8.0%	766,343	841,277	-8.9%
Rocky Mountain Region	5,873,549	3,945,077	48.9%	11,473,314	7,050,746	62.7%
Total	7,257,184	5,041,058	44.0%	14,204,006	9,177,011	54.8%
Natural gas equivalent (Mcfe)						
Appalachian Basin	1,005,981	686,631	46.5%	1,980,177	1,304,272	51.8%
Michigan Basin	392,954	427,392	-8.1%	777,329	853,169	-8.9%
Rocky Mountain Region	7,397,837	5,321,903	39.0%	14,518,800	9,611,672	51.1%
Total	8,796,772	6,435,926	36.7%	17,276,306	11,769,113	46.8%

Index

	Three Months Ended June 30,					Six Months Ended June 30,				
	2008		2007	Percentage Change		2008		2007	Percentage Change
Average Sales Price (excluding derivative gains/losses)										
Oil (per Bbl)										
Appalachian Basin	$	113.11	$	57.66	96.2%	$	104.38	$	54.92	90.1%
Michigan Basin		118.61		58.64	102.3%		108.45		54.69	98.3%
Rocky Mountain Region		123.30		57.00	116.3%		102.22		51.46	98.6%
Total		123.26		57.02	116.2%		102.24		51.50	98.5%
Natural gas (per Mcf)										
Appalachian Basin	$	11.09	$	7.46	48.7%	$	9.79	$	7.06	38.7%
Michigan Basin		10.41		6.79	53.3%		9.02		6.44	40.1%
Rocky Mountain Region		8.87		4.60	92.8%		8.02		5.18	54.8%
Total		9.25		5.16	79.3%		8.31		5.56	49.5%
Natural gas equivalent (per Mcfe)										
Appalachian Basin	$	11.13	$	7.49	48.6%	$	9.82	$	7.09	38.5%
Michigan Basin		10.56		6.84	54.4%		9.15		6.48	41.2%
Rocky Mountain Region		11.27		5.87	92.0%		9.91		6.09	62.7%
Total		11.23		6.10	84.1%		9.86		6.22	58.5%

The increases in oil and gas sales revenue for the current three and six month periods compared to the year periods were due to increased volumes of natural gas and oil along with increased average sales prices of natural gas and oil. Increased volumes of natural gas and oil produced and significantly increased commodity prices contributed $14.4 million and $45.1 million, respectively, to the total $59.5 million increase in oil and gas sales revenue for the current three month period compared to the prior three month period. Increased volumes of natural gas and oil produced and significantly increased commodity prices contributed $34.3 million and $62.8 million, respectively, to the total $97.1 million increase in oil and gas sales revenue for the current six month period compared to the prior six month period. The increases in natural gas and oil volumes for the current three and six month periods resulted from the acquisition of producing oil and gas properties and a significant increase in the number of wells drilled for our own account over the past year.

Further, late in June 2007, we placed into service the upgraded Garden Gulch pipeline and compressor facility, which serves a majority of our wells in the Piceance Basin of our Rocky Mountain Region. This upgrade included two new natural gas compressors, with a third compressor added in the third quarter of 2007, and pipeline facility enhancements. The upgrade and enhancements have increased the capacity of the pipeline delivery system from 17,000 Mcf per day to 60,000 Mcf per day from our wells feeding this facility.

Oil and Natural Gas Pricing. Financial results depend upon many factors, particularly the price of oil and natural gas and our ability to market our production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Oil and natural gas prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets have resulted in a local market oversupply situation from time to time. Such a situation existed in the Rocky Mountain Region during 2007, with production exceeding the local market demand and pipeline capacity to non-local markets. The result, beginning in the second quarter of 2007 and continuing into the fourth quarter of 2007, was a decrease in the price of Rocky Mountain natural gas compared to the New York Mercantile Exchange ("NYMEX") price. The expansion in January 2008 of the Rockies Express pipeline, a major interstate pipeline constructed and operated by a non-affiliated entity, is the primary reason for the narrowing of the NYMEX/Colorado Interstate Gas ("CIG") differential from November 2007 into the first quarter of 2008. The differential has widened again during the current three month period to an average below NYMEX of $2.45. For the remainder of 2008, the differential is currently estimated at $4.22. Once the third phase of the expansion of the Rockies Express is completed in 2009, the pipeline capacity is expected to increase by 64% to 1.8 Bcf/per day of natural gas from the region. Like most producers in the region, we rely on major interstate pipeline companies to construct these facilities to increase pipeline capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is also driven strongly by supply and demand relationships. In the Rocky Mountain Region in 2007, and the first quarter of 2008, the oil prices we received were below the NYMEX oil market due to supply competition from Rocky Mountain and Canadian oil that has driven down market prices.

The price we receive for a large portion of the natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which may include some gas sold at the CIG prices and some sold at mid-continent prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX based.

Although 80.8% of our current six month period natural gas production came from the Rocky Mountain Region, much of our Rocky Mountain natural gas pricing is based upon other indices in addition to CIG. The table below identifies the pricing basis of our oil and natural gas pricing for sales volumes during the current three month period. The pricing basis is the index that most closely relates to the price under which the oil and natural gas is sold. As it indicates, 36% of our oil and natural gas sales are derived from the CIG Index and other similarly priced Rocky Mountain pipelines.

Index

Energy Market Exposure
For the Three Months Ended June 30, 2008

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	Rocky Mountain (CIG, et. al.)	Gas	36.0%
NECO	Mid Continent (Panhandle Eastern)	Gas	27.0%
Colorado/North Dakota	NYMEX	Oil	18.0%
Appalachian	NYMEX	Gas	12.0%
Michigan	Mich-Con/NYMEX	Gas	5.0%
Wattenberg	Colorado Liquids	Gas	2.0%
			100.0%

Lifting Costs. Lifting costs per Mcfe, excluding production taxes which fluctuate with oil and natural gas prices, were $1.13 per Mcfe for both the current three and six month periods, up 6.6% and 25.6%, respectively, from the prior three and six month periods. Production taxes for the current three and six month periods were $0.79 per Mcfe and $0.69 per Mcfe, respectively, compared to $0.43 per Mcfe and $0.44 per Mcfe for the prior three and six month periods. The increase in production taxes for the current three and six month periods is the result of increased average sales prices realized.

Oil and Gas Production and Well Operations Costs. In addition to increased production, the increase in costs is also attributable to additional personnel in the production and engineering staffs, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers associated with the December 2006 and the first quarter 2007 acquisitions and significant general oil field services inflation pressures. Oil and gas production and well operations cost includes our lifting cost, production taxes, the cost to operate wells and pipelines for our sponsored partnerships and other third parties (whose income is included in well operations and pipeline income) and certain production and engineering staff related overhead costs.

Oil and Gas Price Risk Management Gain (Loss), Net

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(in thousands)			
Oil and gas price risk management:				
Realized gain (loss)				
Oil	$ (4,394)	$ (53)	$ (5,700)	$ (105)
Natural gas	(10,960)	80	(12,065)	713
Total realized gain (loss)	(15,354)	27	(17,765)	608
Unrealized gain (loss)	(86,444)	3,715	(126,343)	(2,511)
Oil and gas price risk management gain (loss), net	$ (101,798)	$ 3,742	$ (144,108)	$ (1,903)

The $86.4 million and $126.3 million in unrealized losses for the current three and six month period, respectively, are the fair values of the derivative positions as of June 30, 2008, less the related unrealized amounts recorded in prior periods. The price of both oil and natural gas has declined significantly since June 30, 2008, and if the prices remain at current levels or continue to decline, we expect to experience unrealized derivative gains for the third quarter of 2008.

Oil and gas price risk management loss, net includes realized gains and losses and unrealized changes in the fair value of oil and natural gas derivatives related to our oil and natural gas production. Oil and gas price risk management loss, net does not include commodity based derivative transactions related to transactions from natural gas marketing activities, which are included in sales from and cost of natural gas marketing activities. See Notes 4 and 5 to the accompanying condensed consolidated financial statements for additional details of our derivative financial instruments.

Oil and Gas Derivative Activities. Because of uncertainty surrounding oil and natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through March 2012, we have in place a series of floors, ceilings, collars and fixed price swaps on a portion of our oil and natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor, the counterparty pays us. During the three months ended June 30, 2008, we averaged natural gas volumes sold of 2.4 Bcf per month and oil sales of 85,500 barrels per month.

Index

The following table sets forth our derivative positions in effect as of August 8, 2008, on our share of production by area.

				Floors		Ceilings		Swaps (Fixed Prices)	
Commodity/ Index/ Area	Month Set	Month	Gross Monthly Quantity (Gas-MMbtu Oil -Bbls)	Net Monthly Quantity (Gas-MMbtu Oil -Bbls)	Price	Net Monthly Quantity (Gas-MMbtu Oil -Bbls)	Price	Net Monthly Quantity (Gas-MMbtu Oil -Bbls)	Price
Natural Gas - (CIG) Piceance Basin									
	Feb-08	Jul 08 - Oct 08	750,000	-	$ -	-	$ -	447,075	$ 7.05
	Jan-08	Jul 08 - Oct 08	630,000	-	-	-	-	375,543	6.54
	Apr-08	Nov 08 - Mar 09	570,000	-	-	-	-	339,777	7.76
	Jul-08	Nov 08 - Mar 09	340,000	-	-	-	-	202,674	8.52
	Feb-08	Nov 08 - Mar 09	340,000	-	-	-	-	202,674	8.18
	Jan-08	Apr 09 - Oct 09	570,000	339,777	5.75	339,777	8.75	-	-
	Mar-08	Apr 09 - Oct 09	560,000	333,816	5.75	333,816	9.05	-	-
	Jul-08	Nov 09 - Mar 10	450,000	-	-	-	-	268,245	9.20
	Jul-08	Nov 09 - Mar 10	640,000	381,504	7.50	381,504	11.40	-	-
Wattenberg Field									
	Feb-08	Jul 08 - Oct 08	450,000	-	-	-	-	330,984	7.05
	Jan-08	Jul 08 - Oct 08	290,000	-	-	-	-	217,268	6.54
	Apr-08	Nov 08 - Mar 09	320,000	-	-	-	-	247,268	7.76
	Jul-08	Nov 08 - Mar 09	180,000	-	-	-	-	137,022	8.52
	Feb-08	Nov 08 - Mar 09	180,000	-	-	-	-	137,022	8.18
	Jan-08	Apr 09 - Oct 09	320,000	247,268	5.75	247,268	8.75	-	-
	Mar-08	Apr 09 - Oct 09	290,000	223,880	5.75	223,880	9.05	-	-
	Jul-08	Nov 09 - Mar 10	250,000	-	-	-	-	183,880	9.20
	Jul-08	Nov 09 - Mar 10	360,000	270,738	7.50	270,738	11.40	-	-
Natural Gas - Panhandle Eastern Pipeline ("PEPL") NECO									
	Feb-08	Jul 08 - Oct 08	180,000	-	-	-	-	180,000	7.45
	Jan-08	Jul 08 - Oct 08	120,000	-	-	-	-	120,000	6.80
	Apr-08	Nov 08 - Mar 09	110,000	-	-	-	-	110,000	8.09
	Jul-08	Nov 08 - Mar 09	80,000	-	-	-	-	80,000	9.00
	Feb-08	Nov 08 - Mar 09	80,000	-	-	-	-	80,000	8.44
	Jan-08	Apr 09 - Oct 09	110,000	110,000	6.00	110,000	9.70	-	-
	Mar-08	Apr 09 - Oct 09	130,000	130,000	6.25	130,000	11.75	-	-
	Jul-08	Nov 09 - Mar 10	120,000	-	-	-	-	120,000	10.91
	Jul-08	Nov 09 - Mar 10	170,000	170,000	9.00	170,000	14.00	-	-
Natural Gas - NYMEX Appalachian and Michigan Basins									
	Feb-08	Jul 08 - Oct 08	170,000	-	-	-	-	126,956	8.33

	Feb-08	Jul 08 - Oct 08	170,000	-	-	-	-	126,956	8.58
	Jul-08	Nov 08 - Mar 09	170,000	-	-	-	-	126,956	10.42
	Feb-08	Nov 08 - Mar 09	100,000	74,680	8.40	74,680	13.05	-	-
	Feb-08	Nov 08 - Mar 09	100,000	-	-	-	-	74,680	9.62
	Jan-08	Apr 09 - Oct 09	170,000	126,956	6.75	126,956	12.45	-	-
	Mar-08	Apr 09 - Oct 09	170,000	126,956	7.50	126,956	13.25	-	-
	May-08	Apr 09 - Mar 12	60,000	-	-	-	-	44,808	9.89
	Jul-08	Nov 09 - Mar 10	320,000	238,976	10.00	238,976	17.15	-	-
	Feb-08	Jul 08 - Feb 11	90,000	-	-	-	-	90,000	8.62
Oil - NYMEX									
Wattenberg Field									
	Oct-07	Jul 08 - Dec 08	48,667	-	-	-	-	31,205	84.20
	May-08	Jul 08 - Dec 08	36,686	-	-	-	-	23,523	108.05
	Jan-08	Jan 09 - Dec 09	30,417	-	-	-	-	19,503	84.90
	Jan-08	Jan 09 - Dec 09	30,417	-	-	-	-	19,503	85.40
	May-08	Jan 09 - Dec 09	12,167	-	-	-	-	7,801	117.35
	May-08	Jan 10 - Dec 10	30,417	-	-	-	-	19,503	92.74
	May-08	Jan 10 - Dec 10	30,417	-	-	-	-	19,503	93.17

We use oil and natural gas commodity derivative instruments to manage price risk for ourselves as well as our sponsored drilling partnerships. We set these instruments for ourselves and the partnerships jointly by area of operation. As volumes produced change, the mix between PDC and the partnerships will change. The gross volumes in the above table reflect the total volumes hedged for ourselves and the partnerships jointly by area of operation. The net volumes in the above table reflect our share of the positions in effect as of August 8, 2008.

22

Index

Natural Gas Marketing Activities

The increase in sales from natural gas marketing activities in the current three and six month periods is primarily due to an increase in prices and volumes sold, partially offset by increased unrealized losses on derivative transactions. The increase in cost of natural gas marketing activities in the current three and six month periods is primarily due to an increase in prices and volumes purchased for resale, partially offset by increased unrealized gains on derivative transactions. The contribution margins of approximately 3% to 4% for the current three and six month periods, respectively, have remained relatively unchanged from the prior three and six month periods.

Our natural gas marketing segment specializes in the purchase, aggregation and sale of natural gas production in our eastern operating areas. Through our natural gas marketing segment, we market the natural gas we produce as well as our purchases of natural gas from other producers in the Appalachian Basin, including our affiliated partnerships. Our derivative activities related to natural gas marketing activities include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. We do not take speculative positions on commodity prices.

Other Costs and Expenses

Exploration Expense.

The decreases in exploration expense for the current three and six month periods compared to the prior three and six month periods are primarily due to liquidated damages recognized in prior three and six month periods of $2.7 million related to an exploration agreement with an unaffiliated party and a corresponding $1.1 million write-off of the carrying value of the related leasehold acreage. As of June 30, 2008, we have capitalized exploratory well costs included in oil and gas properties totaling $7 million relating to 11 wells pending the determination of proved reserves. In the period when we make a final determination of the well's productive status, the well will be removed from suspended status and, if determined to be a dry hole, will be expensed to exploration expense.

General and Administrative Expense.

The increase in general and administrative expense for the current three month period compared to the prior three month period is primarily due to increased staffing costs associated with our recent growth. The current six month period includes $3.2 million related to a separation agreement with our former president along with increased staffing costs. No similar separation amounts were recognized in the prior six month period.

Depreciation, Depletion, and Amortization.

The increases in DD&A expense are a result of higher production volumes experienced in 2008 compared to 2007. The DD&A rates for oil and gas properties are shown in the table below for our significant areas of operations.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2008	2007	Percent Change	2008	2007	Percent Change
			(per Mcfe)			
Appalachian Basin	$ 1.52	$ 1.27	19.7%	$ 1.49	$ 1.27	17.3%
Michigan Basin	1.31	1.26	4.0%	1.31	1.26	4.0%

Rocky Mountain Region:						
Wattenberg Field (1)	3.39	2.95	14.9%	3.38	2.93	15.4%
Piceance Basin	1.82	3.00	-39.3%	1.81	2.65	-31.7%
NECO	1.30	1.62	-19.8%	1.30	1.52	-14.5%

(1) The Wattenberg Field contributed 94% of our oil production for both the current three and six month periods, respectively, and 88% and 87.8% for the prior three and six month periods.

The weighted average DD&A rate for oil and gas properties decreased to $2.34 per Mcfe and $2.33 per Mcfe for the current three and six month periods from $2.58 per Mcfe and $2.46 per Mcfe for the prior three and six month periods, respectively. The upward revision in our reserve report at December 31, 2007, due to higher commodity pricing partially offset by increased operation costs, lowered our overall DD&A rate per Mcfe, which was partially offset by the higher cost of well drilling, completion and equipping of new wells. As reflected in the above table of field DD&A rates, the overall changes per Mcfe varied among our major fields depending on whether the increase in reserves out weighed the increase in costs.

Index

Interest Expense

The increase in interest expense in 2008 was due to significantly higher average outstanding balances of our credit facility and the 12% senior notes. Interest expense for the current three and six month periods were offset in part by construction period interest of $0.8 million and $1.4 million, respectively. Interest expense for the prior three and six month periods were similarly offset in part by construction period interest of $0.8 million and $1.3 million, respectively. We utilize our daily cash balances to reduce our line of credit borrowings, lowering our cost of interest.

Provision for Income Taxes

The effective income tax rate, excluding the effect of discrete items, for the current three and six month periods was 32.5% and 33.7%, respectively, compared to 37.1% and 37% for the prior three and six month periods, respectively. The decreased rate is primarily due to the larger tax benefit of our customary tax incentives, principally percentage depletion. In addition, a second quarter discrete benefit of $1.4 million was recorded related to the implementation of state tax strategies that impact prior years. The impact of these strategies also affected our rate used to establish deferred taxes and resulted in a deferred tax benefit of $1.3 million in the current three month period.

Unrealized losses on derivative positions are not deductible and give rise to deferred taxes. Accordingly, for the current six month period, we recorded in other current assets in our accompanying condensed consolidated balance sheet an additional $49.1 million to our deferred tax asset associated with these unrealized losses. Further, the operating loss in the current six month period has resulted in a current net tax benefit of $16.2 million, which is recorded in other current assets as of June 30, 2008.

Liquidity and Capital Resources

Cash flow from operations and our bank credit facility are our primary sources of liquidity to meet operating expenses and fund capital expenditures. As of June 30, 2008, we had a $234.1 million syndicated revolving bank credit facility, of which borrowings under this facility were $51 million. On July, 15, 2008, we entered into a Third Amendment, restating the Company's previous credit agreement dated as of November 4, 2005, as amended, which increases the Company's available borrowing base from $234.1 million to $300 million. Additionally, on July 18, 2008, we entered into a Fourth Amendment which adds certain financial institutions to the bank group and reallocates the credit facility among the banks. On February 8, 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018 for net proceeds received of approximately $196 million, which we used to repay our bank credit facility.

As of July 28, 2008, we had drawn $71.5 million of the $300 million facility. Additionally, we believe that our continued drilling activities will allow us, through our permitted borrowing base redeterminations, to increase the borrowing capacity of the credit facility as additional properties are developed. Based on near-term cash flow projections, the discretionary nature of our capital budget, our bank credit facility capacity and the demonstrated ability to raise capital in bank, private and public markets, we believe that we have sufficient liquidity and capital resources to conduct our business and operations as well as remain compliant with our debt covenants throughout 2008.

Capital Expenditures

We establish and periodically revise a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Our 2008 capital expenditure budget is currently at $319 million: $269 million for drilling and development; $39 million for exploratory drilling, land acquisitions and seismic activities; and $11 million for other capital expenditures. We retain a significant degree of control over the timing of our capital expenditures, which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling schedule, which is largely discretionary.

Our 2008 capital budget does not include acquisitions of significant oil and gas properties. We review acquisition opportunities on an ongoing basis. The acquisition of significant oil and gas properties has in the past been financed largely through the sale of assets or borrowings from our credit facility. If we were to make significant additional acquisitions in the future, we would need to borrow additional amounts under our credit facility, if available, or obtain additional debt or equity financing. Our senior notes impose certain restrictions on our ability to obtain additional debt financing.

Working Capital and Cash Flows

Changes in market prices for oil and natural gas, our ability to increase production and changes in costs are the principal determinants of the level of our cash flow from operations. Oil and natural gas sales in the six months ended June 30, 2008, excluding the impact of the $4.2 million royalty litigation provision, were 132.6% higher than the six months ended June 30, 2007, resulting from a 58.4% increase in average oil and natural gas prices and a 46.8% increase in oil and natural gas production. While a decline in oil and natural gas prices would affect the amount of cash flow that would be generated from operations, we had oil fixed-price swaps, as of August 8, 2008, that we estimate will largely offset price changes for approximately 57% of our expected oil production at an average price of $94.45 per Bbl and fixed price swaps on 66% of our expected natural gas production at an average price of $7.56 for Mcf for the remainder of 2008, thereby reducing the risk of significant declines for a substantial portion of our 2008 cash flow. The remaining 43% and 34% of estimated 2008 oil and natural gas production, respectively, are unhedged and will be impacted by increasing and decreasing commodity market prices. Depending on changes in oil and natural gas futures markets and our view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current derivative positions. Our oil and natural gas derivatives as of August 8, 2008, are detailed above in Results of Operations – Oil and Gas Price Risk Management Loss, Net: Oil and Gas Derivative Activities.

Index

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit facility. Generally, to the extent that we have outstanding borrowing, we use excess cash to pay down borrowings under our credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. Our working capital usage for the six months ended June 30, 2008, was $29 million, largely related to cash used in drilling activities.

Additionally, beginning August 15, 2008, we are required to pay our semi-annual interest payment on our 12% senior notes in the amount of $12.2 million. See Contractual Obligations and Contingent Commitments below detailing projected interest payments through maturity of the notes.

Drilling Activity

The following table summarizes our development and exploratory drilling activity for the three and six months ended June 30, 2008 and 2007. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of producing wells and wells capable of commercial production.

	Drilling Activity Three Months Ended June 30,				Drilling Activity Six Months Ended June 30,			
	2008		2007		2008		2007	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development								
Productive (1)	91.0	82.8	103.0	93.2	183.0	141.6	157.0	131.6
Dry	5.0	5.0	5.0	5.0	5.0	5.0	7.0	6.3
Total development	96.0	87.8	108.0	98.2	188.0	146.6	164.0	137.9
Exploratory								
Productive (1)	-	-	-	-	-	-	3.0	1.0
Dry	4.0	3.8	-	-	6.0	5.8	2.0	0.7
Pending determination	1.0	1.0	-	-	8.0	8.0	-	-
Total exploratory	5.0	4.8	-	-	14.0	13.8	5.0	1.7
Total Drilling Activity	101.0	92.6	108.0	98.2	202.0	160.4	169.0	139.6

(1) As of June 30, 2008, a total of 144 productive wells, 107 drilled in 2008 and 37 drilled in 2007, were waiting to be fractured and/or for gas pipeline connection.

The following table sets forth the wells we drilled by operating area during the periods indicated.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2008		2007		2008		2007	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region:								
Wattenberg	35.0	33.6	38.0	36.4	80.0	55.3	68.0	50.1
Piceance	11.0	11.0	14.0	14.0	32.0	24.5	30.0	28.1
NECO	38.0	32.0	54.0	46.0	67.0	58.6	67.0	59.0
North Dakota	1.0	0.2	-	-	1.0	0.2	2.0	0.6
	85.0	76.8	106.0	96.4	180.0	138.6	167.0	137.8

Total Rocky Mountain Region								
Appalachian Basin	14.0	14.0	-	-	18.0	18.0	-	-
Michigan	1.0	0.8	2.0	1.8	1.0	0.8	2.0	1.8
New York	-	-	-	-	1.0	1.0	-	-
Fort Worth Basin	1.0	1.0	-	-	2.0	2.0	-	-
Total	101.0	92.6	108.0	98.2	202.0	160.4	169.0	139.6

Index

Drilling Programs

In August 2007, we completed the offering of our sponsored drilling partnership, Rockies Region 2007 Limited Partnership, and received subscriptions of approximately $90 million. We contributed $38.7 million for our general partner capital contribution. On December 28, 2007, the drilling partnership prepaid 2008 drilling costs of $54 million, in accordance with the partnership agreement, to secure intangible drilling cost tax deductions for the investing partners. This payment is included in advances for future drilling contracts on our accompanying condensed consolidated balance sheets. As of June 30, 2008, we have drilled all of the wells pertaining to Rockies Region 2007 Limited Partnership. The balance of the partnership's prepayment at June 30, 2008, was $14.5 million and represents the remaining costs to complete the wells drilled. In January 2008, we announced that we do not plan to sponsor a new drilling partnership in 2008.

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of June 30, 2008:

	Payments due by period				
Contractual Obligations and Contingent Commitments (1)	Total	Less than 1 year	1-3 years (in thousands)	3-5 years	More than 5 years
Long-Term Debt (2)	$ 254,000	$ -	$ 51,000	$ -	$ 203,000
Interest on long-term debt(2)	262,477	33,731	67,102	48,720	112,924
Operating leases	4,963	2,374	2,002	537	50
Asset retirement obligations	21,849	50	100	100	21,599
Rig commitments (3)	21,182	12,442	8,740	-	-
Drilling Commiments(4)	3,142	-	667	-	2,475
Derivative agreements (5)	201,198	135,561	65,071	566	-
Other liabilities (6)	8,511	245	720	720	6,826
Total	$ 777,322	$ 184,403	$ 195,402	$ 50,643	$ 346,874

(1) Table does not include maximum annual repurchase obligation of $9.7million as of June 30, 2008, see Note 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements.
(2) Amounts presented for long term debt consist of amounts related to our 12% senior notes and our outstanding credit facility. The interest on long term debt includes $234.6 million payable to the holders of our 12% senior notes and $27.8 million related to our outstanding balance of $51 million on our credit facility as of June 30, 2008, based on an imputed interest rate of 4%.
(3) Drilling rig commitments in the above table do not include future adjustments to daily rates as provided for in the agreements as such increases are not predictable and are only included in the above obligation table upon notification to us by the contractor of an increase in the rate.

(4) Amounts represent our maximum obligation for potential liquidating damages if we do not comply with certain drilling and development agreements. See Note 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements. These amounts do not include advances for future drilling contracts totaling $15.1 million at June 30, 2008.
(5) Amounts represents gross liability related to fair value of derivatives, including the fair value of derivative contracts we entered into on behalf of our affiliate partnerships as the managing general partner. We have a related net receivable from the partnerships of $56.5 million as of June 30, 2008.
(6) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

Commitments and Contingencies

See Note 7, Commitments and Contingencies, to the accompanying condensed consolidated financial statements.

Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements.

Critical Accounting Polices and Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with accounting principles generally accepted in the U.S. requires management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses.

Index

We believe that our accounting policies for revenue recognition, derivatives instruments, oil and gas properties, deferred income tax asset valuation and purchase accounting are based on, among other things, judgments and assumptions made by management that include inherent risks and uncertainties. There have been no significant changes to these policies or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the consolidated financial statements and accompanying notes contained in our annual report on Form 10-K for the fiscal year ended December 31, 2007, filed with the SEC on March 20, 2008.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has established risk management processes to monitor and manage these market risks.

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, Critical Accounting Policies and Estimates-Accounting for Derivatives Contracts at Fair Value, of our 2007 Form 10-K for further discussion of the accounting for derivative contracts.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates primarily as it relates to interest we earn on our cash, cash equivalents and designated cash and interest we pay on borrowings under our revolving credit facility. Our interest-bearing cash and cash equivalents includes our money market accounts, short-term certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of June 30, 2008, is $1 million with an average interest rate of 1.7%.

In February 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018, which we utilized to pay down our variable rate credit facility. The fixed-price debt transaction reduced our current sensitivity to interest rate fluctuations.

Commodity Price Risk

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 marketing activities. 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.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe these valuation methods are appropriate and consistent with those 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.

Economic Hedging Strategies. Our results of operations and operating cash flows are 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 June 30, 2008, our oil and natural gas derivative instruments were comprised of futures, swaps and collars. These instruments generally consist of (i) NYMEX-traded natural gas contracts for Appalachian and Michigan production, (ii) PEPL-based contracts for NECO production, (iii) 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 derivative contract 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 fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price is between the call and the put strike price, no payments are due from either party.

Index

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 derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

The following table presents monthly average NYMEX and CIG closing prices for oil and natural gas for the six months ended June 30, 2008, and the year ended December 31, 2007, as well as average sales prices we realized for the respective commodity.

	Six Months Ended June 30, 2008	Year Ended December 31, 2007
Average Index Closing Prices		
Oil (per Barrel)		
NYMEX	$ 105.67	$ 69.79
Natural Gas (per MMbtu)		
NYMEX	9.48	6.89
CIG	7.72	3.97
Average Sales Price		
Oil	102.24	60.65
Natural Gas	8.31	5.33

Based on a sensitivity analysis as of June 30, 2008, it was estimated that a 10% increase in oil and natural gas prices over the entire period for which we have derivatives currently in place would have resulted in an increase in unrealized losses of $64.4 million and a 10% decrease in oil and natural gas prices would have resulted in a decrease in unrealized losses of $67 million.

See Note 4, Derivative Financial Instruments, to our accompanying condensed consolidated financial statements included in this report for additional disclosure regarding derivative instruments including, but not limited to, a summary of our open derivative positions as of June 30, 2008.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. To reduce credit exposure, we seek to enter into netting agreements with counterparties that permit us to offset receivables and payables with such counterparties. We attempt to further reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We have had no counterparty default losses.

Disclosure of Limitations

Because the information above included only those exposures that exist at June 30, 2008, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our hedging strategies at the time, and interest rates and commodity prices at the time.

Item 4. Controls and Procedures

2007 Material Weaknesses

As discussed in our 2007 Form 10-K, we did not maintain effective controls as of December 31, 2007, over the (1) completeness, accuracy, validity and restricted access of certain key financial statement spreadsheets that support all significant balance sheet and income statement accounts and (2) policies and procedures, or personnel with sufficient technical expertise to record derivative activities in accordance with generally accepted accounting principles.

Index

Evaluation of Disclosure Controls and Procedures

As of June 30, 2008, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(e) and 15d-15(e). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as a result of the material weaknesses cited above, our disclosure controls and procedures were not effective as of June 30, 2008. Because of these material weaknesses, we performed additional procedures to ensure that our accompanying condensed consolidated financial statements as of and for the six months ended June 30, 2008, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

There were no material changes in internal control over financial reporting in the second quarter of 2008. During the first quarter of 2008, we made the following changes in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect our internal control over financial reporting:

During the first quarter of 2008, we implemented the general ledger, accounts receivable, and joint interest billing modules as part of our new broader financial reporting system. We plan to implement additional modules in 2008 to support the remaining processes and operations. We believe the phased-in approach we are taking reduces the risks associated with the implementation. We have taken the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps include providing training related to business process changes and the financial reporting system software to individuals using the financial reporting system to carry out their job responsibilities as well as those who rely on the financial information. We anticipate that the implementation of the financial reporting system will strengthen the overall systems of internal controls due to enhanced automation and integration of related processes. We are modifying the design and documentation of internal control process and procedures relating to the new system to supplement and complement existing internal controls over financial reporting. The system changes were undertaken to integrate systems and consolidate information, and were not undertaken in response to any actual or perceived deficiencies in our internal control over financial reporting. Testing of the controls related to these new systems is ongoing and is included in the scope of our assessment of our internal control over financial reporting for 2008.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding our legal proceedings can be found in Note 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements included in this report.

Item 1A. Risk Factors

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of common stock are described under Item 1A, Risk Factors, of our annual report on Form 10-K for the year ended December 31, 2007, as filed with the SEC on March 20, 2008. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC. There have been no material changes from the risk factors previously disclosed in our 2007 Form 10-K, except the addition of the third paragraph to the following risk factor:

Index

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon natural gas and oil wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment includes federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation by natural gas and oil-producing states of conservation practices and protection of correlative rights. These regulations affect our operations, increase our costs of exploration and production and limit the quantity of natural gas and oil that we can produce and market. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals, drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase our financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff.

Illustrative of these risks are regulations currently proposed by the State of Colorado which target the oil and gas industry. These multi-faceted proposed regulations significantly enhance requirements regarding oil and gas permitting, environmental requirements, and wildlife protection. The wildlife protection requirements, in particular, could require an intensive wildlife survey prior to any drilling, and may further entirely prohibit drilling for extended periods during certain wildlife breeding seasons. Many landowners and energy companies are strenuously opposing these proposed regulatory changes, and it is impossible at this time to assess the form of the final regulations or the cost to our company. Significant permitting delays and increased costs could result from any final regulations.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs

April 1-30, 2008	153	$ 75.23	153	-
May 1-31, 2008 (1)	3,869	73.55	-	
June 1-30, 2008 (1)	379	68.38	-	
	4,401		153	

(1) Represents shares purchased to satisfy the tax withholding pursuant to stock based compensation plans.

On October 16, 2006, our Board of Directors approved a share purchase program authorizing us to purchase up to 10% of our then outstanding common stock (1,477,109 shares) through April 2008. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that we deemed appropriate. Shares were purchased at fair market value based on the closing price on the date of purchase and were purchased primarily to satisfy the statutory minimum tax withholding requirement for restricted stock that vested and options exercised in 2008. As the share purchase program expired on April 30, 2008, the total shares purchased pursuant to this program were 76,283 shares at an average price of $65.73, which includes 68,943 shares purchased from executives at an average price of $67.22. All shares have been subsequently retired. The authorization for the purchase of the remaining 1,400,826 shares effectively expired on April 30, 2008.

Index

Items 3. – Defaults Upon Senior Securities

None.

Item 4. – Submission of Matters to a Vote of Security Holders

The following provides a summary of votes cast for the proposals on which our shareholders voted at our annual meeting of shareholders held on June 23, 2008, in Morgantown, West Virginia.

(1) To elect directors:

Nominee	For	Withheld
Joseph E. Casabona	12,801,648	866,640
Richard W. McCullough	12,434,529	1,233,759
Larry F. Mazza	13,459,300	208,988
David C. Parke	6,914,276	6,754,012
Jeffrey C. Swoveland	6,952,765	6,715,523

The following director terms continued after the annual meeting of shareholders.

Director	Term Expiring
Kimberly Luff Wakim	2009
Anthony J. Crisafio	2009
Steven R. Williams	2009
Vincent F. D'Annunzio	2010

(2) To amend and restate the Company’s Articles of Incorporation to: (1) increase the number of authorized shares of common stock, par value $0.01, of the Company from 50,000,000 shares to 100,000,000 shares, and (2) authorize 50,000,000 shares of preferred stock, par value $0.01, of the Company, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by the Company’s Board of Directors from time to time:

For	Against	Abstain
7,851,423	3,984,566	17,522

(3) To amend and restate the Company’s 2005 Non-Employee Director Restricted Stock Plan to, as material, increase the number of shares authorized under the plan from 40,000 to 100,000 and change the vesting provisions:

For	Against	Abstain
10,868,505	975,575	9,431

(4) To ratify the selection of PricewaterhouseCoopers LLP as independent registered public accounting firm for the Company for the year ending December 31, 2008:

For	Against	Abstain
13,115,752	546,365	6,170

Item 5. – Other Information

None.

Index

Item 6. – Exhibits

Exhibit No.	Description
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.

Index

SIGNATURES

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

Petroleum Development Corporation
(Registrant)

Date:	August 8, 2008	/s/ Richard W. McCullough Richard W. McCullough Chief Executive Officer, President and Chief Financial Officer (principal executive officer and principal financial officer)
		/s/ Darwin L. Stump Darwin L. Stump Chief Accounting Officer (principal accounting officer)