PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 06, 2008

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

FORM 10-Q

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

OR

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

Commission File Number: 000-07246

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o

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

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

PETROLEUM DEVELOPMENT CORPORATION

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

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

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

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

*Derived from audited 2007 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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

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

See accompanying notes to condensed consolidated financial statements.

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

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

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

See accompanying notes to condensed consolidated financial statements.

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

1. GENERAL

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

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

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

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

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

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

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

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

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

Recently Issued Accounting Standards

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

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

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

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3. PROPERTIES AND EQUIPMENT

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

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

Suspended Well Costs.

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

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

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

4. DERIVATIVE FINANCIAL INSTRUMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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6. LONG-TERM DEBT

Long-term debt consists of the following:

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

Credit facility

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

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

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

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

12% Senior Notes Due 2018

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

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

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

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

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

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

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

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

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

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

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

7. COMMITMENTS AND CONTINGENCIES

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

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

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

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

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

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

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

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

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

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

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

8. STOCK-BASED COMPENSATION

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

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

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

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

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

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

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

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

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

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Restricted Stock Awards

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

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

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

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

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

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

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

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

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

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

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

Common and Preferred stock

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

9. INCOME TAXES

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

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

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

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

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

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10. EARNINGS PER SHARE

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

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

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

11. BUSINESS SEGMENTS

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

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

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

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

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

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

NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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Overview

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

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

resents percentages in excess of 250%

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

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

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

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

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

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

			2008	
Commodity	Index	June 30,	September 30,	October 30,
Natural gas:	NYMEX	$ 12.52	$ 8.21	$ 7.29
	CIG	$ 8.86	$ 5.46	$ 4.89
Oil:	NYMEX	$ 140.15	$ 103.63	$ 72.24

The above dramatic commodity price declines from June 30, 2008, to September 30, 2008, relative to our current hedge positions, resulted in the significant unrealized derivative gains for the third quarter. If the decline in prices from September 30, 2008, to October 30, 2008, continues or remains the same at December 31, 2008, unrealized derivatives gains on our current positions will continue.

The $45.8 million in unrealized gains for the current nine month period is the fair value of the derivative positions as of September 30, 2008, less the related unrealized amounts recorded in prior periods. An unrealized gain 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.

Results of Operations

General

Total revenues for oil and natural gas sales activities for the current three and nine month periods, excluding our royalty litigation provision, $4.0 million for the nine month period, increased 123.4% and 129.1%, respectively, over the same prior year periods. This increase was driven by oil and gas production which increased for the current three and nine month periods by 31.7% and 40.8%, respectively, along with increases in oil and gas commodity prices of

69.4% and 62.6%, respectively.

We became a party to a royalty lawsuit in May 2007. During the second quarter of 2008, in addition to amounts accrued in 2007, we recorded a $4.2 million royalty litigation loss provision. On October 10, 2008, we reached a tentative settlement for $5.8 million resulting in a recapture of $0.2 million of our previous estimated loss provision in the third quarter of 2008. See Note 7 of the accompanying condensed consolidated financial statements for a discussion of the related lawsuit.

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Oil and Natural Gas Production and Sales Activity by Area

	Three Months Ended September 30, 2008	2007	Percentage Change	Nine Months Ended September 30, 2008	2007	Percentage Change
Production						
Oil (Bbls)						
Appalachian Basin	2,467	602	309.8%	5,105	3,816	33.8%
Michigan Basin	944	1,003	-5.9%	2,775	2,985	-7.0%
Rocky Mountain Region	318,722	233,130	36.7%	826,303	659,951	25.2%
Total	322,133	234,735	37.2%	834,183	666,752	25.1%
Natural gas (Mcf)						
Appalachian Basin	931,150	606,165	53.6%	2,895,499	1,891,153	53.1%
Michigan Basin	391,316	421,909	-7.3%	1,157,659	1,263,186	-8.4%
Rocky Mountain Region	6,916,539	5,284,103	30.9%	18,389,853	12,334,849	49.1%
Total	8,239,005	6,312,177	30.5%	22,443,011	15,489,188	44.9%
Natural gas equivalent (Mcfe)						
Appalachian Basin	945,952	609,777	55.1%	2,926,129	1,914,049	52.9%
Michigan Basin	396,980	427,927	-7.2%	1,174,309	1,281,096	-8.3%
Rocky Mountain Region	8,828,871	6,682,883	32.1%	23,347,671	16,294,555	43.3%
Total	10,171,803	7,720,587	31.7%	27,448,109	19,489,700	40.8%

	Three Months Ended September 30, 2008	2007	Percentage Change	Nine Months Ended September 30, 2008	2007	Percentage Change
Average Sales Price (excluding derivative gains/losses)						
Oil (per Bbl)						
Appalachian Basin	$ 108.68	$ 68.19	59.4%	$ 105.93	$ 57.06	85.6%
Michigan Basin	118.92	71.90	65.4%	112.38	60.46	85.9%
Rocky Mountain Region	108.00	63.63	69.7%	104.45	55.75	87.4%
Weighed average price	108.04	63.67	69.7%	104.48	55.78	87.3%
Natural gas (per Mcf)						
Appalachian Basin	10.40	6.16	68.8%	9.99	6.76	47.8%
Michigan Basin	9.67	5.24	84.5%	9.24	6.04	53.0%
Rocky Mountain Region	7.37	4.45	65.6%	7.78	4.87	59.8%
Weighed average price	7.82	4.67	67.5%	8.13	5.20	56.3%
Natural gas equivalent (per Mcfe)						
Appalachian Basin	10.43	6.18	68.8%	10.02	6.79	47.6%
Michigan Basin	9.84	5.33	84.6%	9.38	6.10	53.8%
Rocky Mountain Region	9.68	5.74	68.6%	9.82	5.95	65.0%
Weighed average price	9.76	5.76	69.4%	9.82	6.04	62.6%

The increases in oil and gas sales revenue for the current three and nine month periods compared to the prior 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 $23.9 million and $30.9 million, respectively, to the total $54.8 million increase in oil and gas sales revenue for the current three month period compared to the prior three month period, exclusive of the royalty litigation provision. Increased volumes of natural gas and oil produced and significantly increased commodity prices contributed $78.2 million and $73.7 million, respectively, to the total $151.9 million increase in oil and gas sales revenue for the current nine month period compared to the prior year nine month period, exclusive of the royalty litigation provision. The increases in natural gas and oil volumes for the current three and nine month periods resulted from the significant increase in the number of wells drilled for our own account over the past year, and to a lesser extent, the acquisition of producing oil and gas properties.

We are currently experiencing a 10% to 15% curtailment of production volumes in the Piceance Basin due to limited compression and pipeline capacity, which is anticipated to continue through most of the fourth quarter.

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 (“Rex 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. However, a substantial portion of the new capacity created by the Rex pipeline is now under contract. The differential has widened again during the current three month period to an average below NYMEX of $4.34. For the remainder of 2008, the differential is currently estimated at $3.14. 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.

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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 83.9% of our current three 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, 37% of our oil and natural gas sales are derived from the CIG Index and other similarly priced Rocky Mountain pipelines.

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

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	Colorado Interstate Gas (CIG)	Gas	37.0%
Piceance	San Juan Basin/Southern California	Gas	13.0%
NECO	Mid Continent (Panhandle Eastern)	Gas	15.0%
Colorado/North Dakota	NYMEX	Oil	17.0%
Appalachian	NYMEX	Gas	11.0%
Michigan	Mich-Con/NYMEX	Gas	4.0%
Wattenberg	Colorado Liquids	Gas	2.0%
Other	Other	Gas	1.0%
			100.0%

Lifting Costs. Lifting costs per Mcfe, excluding production taxes which fluctuate with oil and natural gas prices, were \$0.94 and \$1.07 per Mcfe for the current three and nine month periods, respectively, up 9.3% and 20.2%, respectively, from the prior three and nine month periods. Production taxes for the current three and nine month periods were \$0.70 per Mcfe and \$0.68 per Mcfe, respectively, compared to \$0.40 per Mcfe and \$0.42 per Mcfe for the prior three and nine month periods. The increase in production taxes for the current three and nine month periods is the result of increased average sales prices realized. Lifting costs per Mcfe, excluding production taxes, decreased from \$1.13 for the first two quarters of 2008 to \$0.94 Mcfe for the third quarter of 2008. As production volumes increase when we add new wells, we can expect to see modest decreases in lifting costs as we work on improving and stabilizing our lifting costs. In our Rocky Mountain Region, we traditionally experience higher lifting costs due to severe winter conditions for costs such as snow removal from well and access roads, along with other weather related problems.

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.

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Oil and Gas Price Risk Management, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Oil and gas price risk management:				
Realized gain (loss)				
Oil	$ (4,157)	$ (54)	$ (9,857)	$ (159)
Natural gas	1,405	2,545	(10,660)	3,257
Total realized gain (loss)	(2,752)	2,491	(20,517)	3,098
Unrealized gain	172,154	3,854	45,811	1,344
Oil and gas price risk management gain, net	$ 169,402	$ 6,345	$ 25,294	$ 4,442

The $172.2 million and $45.8 million in unrealized gains for the current three and nine month period, respectively, are the fair values of the derivative positions as of September 30, 2008, less the related unrealized amounts recorded in prior periods. The significant declines in oil and natural gas prices from June 2008 to September 2008, was the reason for the current three and nine month unrealized gains. The price of both oil and natural gas has continued to decline since September 30, 2008, and if the prices remain at current levels or continue to decline, we expect to experience additional unrealized derivative gains for the fourth quarter of 2008.

Oil and gas price risk management gain, 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 gain, 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 September 30, 2008, we averaged natural gas volumes sold of 2.7 Bcf per month and oil sales of 107,400 barrels per month.

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The following table sets forth our derivative positions in effect as of October 31, 2008, on our share of production by area.

Commodity/ Index/ Area	Month Set	Month	Floors Net Monthly Quantity (Gas -MMbtu Oil -Bbls)	Floors Price	Ceilings Net Monthly Quantity (Gas -MMbtu Oil -Bbls)	Ceilings Price	Swaps (Fixed Prices) Net Monthly Quantity (Gas-MMbtu Oil -Bbls)	Swaps (Fixed Prices) Price
Natural Gas - Piceance Basin	(CIG)							
	Feb-08	Oct-08	-	$ -	-	$ -	489,793	$ 7.05
	Jan-08	Oct-08	-	-	-	-	411,426	6.54
	Apr-08	Nov 08 - Mar 09	-	-	-	-	363,000	7.76
	Jun-08	Nov 08 - Mar 09	-	-	-	-	216,526	8.52
	Feb-08	Nov 08 - Mar 09	-	-	-	-	216,526	8.18
	Jan-08	Apr 09 - Oct 09	355,827	5.75	355,827	8.75	-	-
	Mar-08	Apr 09 - Oct 09	349,584	5.75	349,584	9.05	-	-
	Jul-08	Nov 09 - Mar 10	-	-	-	-	292,250	9.20
	Jul-08	Nov 09 - Mar 10	415,645	7.50	415,645	11.40	-	-
Wattenberg Field								
	Feb-08	Oct-08	-	-	-	-	380,641	7.05
	Jan-08	Oct-08	-	-	-	-	247,614	6.54
	Apr-08	Nov 08 - Mar 09	-	-	-	-	268,392	7.76
	Jun-08	Nov 08 - Mar 09	-	-	-	-	149,504	8.52
	Feb-08	Nov 08 - Mar 09	-	-	-	-	149,504	8.18
	Jan-08	Apr 09 - Oct 09	266,683	5.75	266,683	8.75	-	-
	Mar-08	Apr 09 - Oct 09	241,530	5.75	241,530	9.05	-	-
	Jul-08	Nov 09 - Mar 10	-	-	-	-	212,191	9.20
	Jul-08	Nov 09 - Mar 10	305,554	7.50	305,554	11.40	-	-
Natural Gas - Panhandle Eastern Pipeline ("PEPL")								
NECO								
	Feb-08	Oct-08	-	-	-	-	180,000	7.45
	Jan-08	Oct-08	-	-	-	-	120,000	6.80
	Apr-08	Nov 08 - Mar 09	-	-	-	-	110,000	8.09
	Jun-08	Nov 08 - Mar 09	-	-	-	-	80,000	9.00
	Feb-08	Nov 08 - Mar 09	-	-	-	-	80,000	8.44
	Jan-08	Apr 09 - Oct 09	110,000	6.00	110,000	9.70	-	-
	Mar-08	Apr 09 - Oct 09	130,000	6.25	130,000	11.75	-	-
	Jul-08	Nov 09 - Mar 10	-	-	-	-	120,000	10.91
	Jul-08	Nov 09 - Mar 10	170,000	9.00	170,000	14.00	-	-
Natural Gas - NYMEX								
Appalachian and Michigan Basins								
	Feb-08	Oct-08	-	-	-	-	147,684	8.33
	Feb-08	Oct-08	-	-	-	-	147,684	8.58

	Jun-08	Nov 08 - Mar 09	-	-	-	-	147,392	10.43
	Feb-08	Nov 08 - Mar 09	86,701	8.40	86,701	13.05	-	-
	Feb-08	Nov 08 - Mar 09	-	-	-	-	86,701	9.62
	Jan-08	Apr 09 - Oct 09	150,869	6.75	150,869	12.45	-	-
	Mar-08	Apr 09 - Oct 09	150,869	7.50	150,869	13.25	-	-
	May-08	Apr 09 - Mar 12	-	-	-	-	52,221	9.89
	Jul-08	Nov 09 - Mar 10	283,225	10.00	283,225	17.15	-	-
	Feb-08	Oct 08 - Feb 11	-	-	-	-	90,000	8.62
Oil - NYMEX								
Wattenberg Field								
	Oct-07	Oct 08 - Dec 08	-	-	-	-	35,841	84.20
	May-08	Oct 08 - Dec 08	-	-	-	-	26,880	108.05
	Jan-08	Jan 09 - Dec 09	-	-	-	-	21,713	84.90
	Jan-08	Jan 09 - Dec 09	-	-	-	-	21,713	85.40
	May-08	Jan 09 - Dec 09	-	-	-	-	8,685	117.35
	May-08	Jan 10 - Dec 10	-	-	-	-	22,070	92.74
	May-08	Jan 10 - Dec 10	-	-	-	-	22,070	93.17

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Natural Gas Marketing Activities

The increase in sales from natural gas marketing activities in the current three and nine month periods is primarily due to an increase in prices and volumes sold. The increase in cost of natural gas marketing activities in the current three and nine month periods is primarily due to an increase in prices, volumes purchased for resale, and increased unrealized gains on derivative transactions.

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 increase in exploration expense for the three months ended September 30, 2008 compared to the same prior three month period was due to an increase in impaired leasehold acreage of approximately $2.9 million and exploratory dry hole costs of $3.6 million, offset in part by a decrease in geological and geophysical costs of $1.5 million. The increase in exploration expense for the nine months ended September 30, 2008 compared to the same prior nine month period was due to an increase in exploratory dry hole costs of $3.6 million and higher exploration department overhead, offset in part by lower geological and geophysical costs of approximately $1.8 million and expired and impairment acreage costs.

General and Administrative Expense.

The increase in general and administrative expense for both the current three and nine month periods compared to the same prior year periods is primarily due to a separation agreement with our former president in the amount of $3.2 million in the first quarter of 2008, and an agreement with our former chief executive officer in the amount of $1.1 million in the current three month period. While our general and administrative costs, including $4.3 million related to the above events, increased during these periods, on a per Mcfe basis, our general and administrative expense decreased from $0.97 per Mcfe for the prior year three month period to $0.80 per Mcfe for the current three month period and from $1.12 per Mcfe for the prior year nine month period to $0.99 per Mcfe for the current nine 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 September 30,			Nine Months Ended September 30,		
	2008	2007	Percent Change	2008	2007	Percent Change
			(per Mcfe)			
	$ 1.57	$ 1.27	23.6%	$ 1.52	$ 1.27	19.7%

Appalachian Basin (1)						
Michigan Basin	1.31	1.28	2.3%	1.31	1.27	3.1%
Rocky Mountain Region:						
Wattenberg Field (2)	3.37	3.06	10.1%	3.38	2.98	13.4%
Piceance Basin (3)	2.33	2.49	-6.4%	2.01	2.57	-21.8%
NECO	1.40	1.57	-10.8%	1.34	1.54	-13.0%
Weighted Average	2.56	2.50	2.4%	2.42	2.48	-2.4%

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(1) The increase in DD&A rates for the Appalachian Basin for both the three and nine month periods compared to the same prior year periods are higher due to the higher market price of a recent acquisition, the fourth quarter 2007 acquisition of 752 wells in southwestern Pennsylvania.

(2) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its oil production, currently more than offsets this cost difference. The Wattenberg Field contributed 95.3% and 94.5% of our oil production for the current three and nine month periods, respectively, and 88.5% and 89.6% for the prior year three and nine month periods.

(3) The decrease in DD&A rates for the Piceance Basin for both the current three and nine month periods compared to the same prior year periods is the result of higher year-end 2007 oil and gas reserves, due primarily to the increase in year-end prices.

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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 is net of capitalized interest. Capitalized interest for the current three and nine month periods were $0.5 million and $1.9 million, and for the prior year three and nine month periods were $1.0 million and $2.3 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 nine month periods was 35.7% and 37.1%, respectively, compared to 40.8% and 37.7% for the prior three and nine month periods, respectively. The decreased rate for the nine month period is primarily due to a 0.5% reduction in our effective state tax rate because of the current year benefit of our implemented state tax planning strategies. Our nine month effective tax rate, after the effect of discrete items, is 34%. This reduced rate reflects second and third quarter discrete benefits of, $1.4 million for each period, related principally 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 million in the current nine month period.

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 September 30, 2008, we had a $300 million syndicated revolving bank credit facility, of which borrowings under this facility were $122 million. 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 and reallocated the credit facility among the banks. 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.

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 and our bank credit facility capacity, 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 the next year.

At this point, we do not believe our liquidity has been materially affected by the recent events in the global financial markets and we do not expect our liquidity to be materially impacted in the near future. We will continue to monitor our liquidity and the credit markets. Additionally, we will continue to monitor events and circumstances surrounding each of our twelve lenders in our bank credit facility. To date we have experienced no disruptions in our ability to access the bank credit facility. However, we cannot predict with any certainty the impact to us of any further disruption in the credit environment. We are in the process of soliciting our bank syndicate and additional banks to increase our revolving bank credit facility Borrowing Base and related bank commitments by $75 million to $375 million. While we can make no assurances as to the success of this initiative, we remain encouraged by its progress to date. We expect to finalize this transaction in mid November 2008.

Capital Expenditures

We establish and periodically revise a capital budget for each calendar year based on development opportunities, expected cash flow from operations and market conditions. Our 2008 capital expenditure budget was previously established at $319 million. However, with the recent significant decline in commodity prices and market conditions, we expect our 2008 capital expenditures to approximate $305 million, below our $319 million budget, and will likely decrease our expected capital budget for 2009. 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.

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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 nine months ended September 30, 2008, excluding the impact of the $4 million royalty litigation provision, were 129.1% higher than the nine months ended September 30, 2007, resulting from a 62.6% increase in average oil and natural gas prices and a 40.8% 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 have oil fixed-price swaps that we estimate will largely offset price changes for approximately 53% of our expected oil production at an average price of $94 per Bbl and fixed price swaps on 66% of our expected natural gas production at an average price of $7.94 per Mcf for the remainder of 2008, thereby reducing the risk of significant declines for a substantial portion of our 2008 cash flow. The remaining 47% 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 October 31, 2008, are detailed above in Results of Operations – Oil and Gas Price Risk Management, Net: Oil and Gas Derivative Activities.

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 nine months ended September 30, 2008, was $55 million, largely related to cash used in drilling activities.

On August 15, 2008, we paid our first 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 nine months ended September 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 September 30,				Nine Months Ended September 30,			
	2008		2007		2008		2007	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development								
Productive (1)	87.0	84.9	93.0	78.8	270.0	226.4	250.0	210.3
Dry	2.0	2.0	1.0	1.0	7.0	7.0	8.0	7.4
Total development	89.0	86.9	94.0	79.8	277.0	233.4	258.0	217.7
Exploratory								
Productive (1)	-	-	-	-	5.0	5.0	1.0	0.2
Dry	1.0	1.0	1.0	1.0	9.0	8.8	5.0	2.5
Pending determination	6.0	5.8	-	-	7.0	6.8	-	-
Total exploratory	7.0	6.8	1.0	1.0	21.0	20.6	6.0	2.7

Total Drilling Activity	96.0	93.7	95.0	80.8	298.0	254.0	264.0	220.4

(1) Of the total productive wells as of September 30, 2008, 89 drilled in 2008 and 17 drilled in 2007, were waiting to be fractured and/or for gas pipeline connection.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2008		2007		2008		2007	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region:								
Wattenberg	36.0	36.0	41.0	29.4	116.0	91.3	109.0	79.5
Piceance	18.0	18.0	11.0	8.5	50.0	42.4	41.0	36.6
NECO	21.0	19.6	39.0	38.9	88.0	78.2	106.0	97.9
North Dakota	1.0	0.3	-	-	2.0	0.5	2.0	0.6
Total Rocky Mountain Region	76.0	73.9	91.0	76.8	256.0	212.4	258.0	214.6
Appalachian Basin	18.0	18.0	4.0	4.0	36.0	36.0	4.0	4.0
Michigan	1.0	0.8	-	-	2.0	1.6	2.0	1.8
New York	-	-	-	-	1.0	1.0	-	-
Fort Worth Basin	1.0	1.0	-	-	3.0	3.0	-	-
Total	96.0	93.7	95.0	80.8	298.0	254.0	264.0	220.4

Contractual Obligations and Contingent Commitments

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

		Payments due by period			
Contractual Obligations and Contingent Commitments (1)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-Term Debt (2)	$ 322,294	$ -	$ 122,000	$ -	$ 200,294
Interest on long-term debt(2)	240,664	30,227	55,141	48,720	106,576
Operating leases	4,628	2,298	1,884	399	47
Asset retirement obligations	22,421	50	100	100	22,171
Rig commitments (3)	19,438	12,442	6,996	-	-
Drilling Commitments(4)	62,545	-	60,395	-	2,150
Derivative agreements (5)	25,250	13,840	11,400	10	-
Other liabilities (6)	8,527	245	720	720	6,842
Total	$ 705,767	$ 59,102	$ 258,636	$ 49,949	$ 338,080

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(1) Table does not include maximum annual repurchase obligation of $12.9 million as of September 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 $228.4 million payable to the holders of our 12% senior notes and $12.3 million related to our outstanding balance of $122 million on our credit facility as of September

30, 2008, based on an imputed interest rate of 4.8%.

(3) Drilling rig commitments in the above table reflects our maximum obligation and does 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) Primarily represents our capital expenditure commitment related to 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 $5.2 million at September 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 receivable from the partnerships of $6.2 million as of September 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.

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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.

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 September 30, 2008, is $89.9 million with an average interest rate of 1.6%.

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 September 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.

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- 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.

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. We have evaluated the credit risk of our receivables from our counterparties using credit default swap values for each counterparty with the outstanding hedge positions for the appropriate time period to calculate the maximum exposure. We have evaluated the maximum exposure and determined that it is immaterial.

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

	Nine Months Ended September 30, 2008	Year Ended December 31, 2007
Average Index Closing Prices:		
Oil (per Barrel)		
NYMEX	$ 112.39	$ 69.79
Natural Gas (per MMbtu)		
NYMEX	9.73	6.89
CIG	7.09	3.97
Average Sales Price:		
Oil	104.48	60.65
Natural Gas	8.13	5.33

Based on a sensitivity analysis as of September 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 $39.4 million and a 10% decrease in oil and natural gas prices would have resulted in a decrease in unrealized losses of $43.2 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 September 30, 2008.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to 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.

Our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries related to our gas marketing group. We monitor their credit worthiness through credit reports and rating agency reports.

Our commodity-based derivative contracts expose us to the credit risk of non-performance by the counterparty to the contracts. These contracts consist of fixed price swaps and collars. We use two investment grade financial institutions as our counterparties to our derivative contracts, who are also our major lenders in our credit facility arrangement. We have evaluated the credit risk of our receivables from our counterparties using credit default swap values for each counterparty with the outstanding hedge positions for the appropriate time period to calculate the maximum exposure. We have evaluated the maximum exposure and determined that it is immaterial.

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The recent disruption in the credit market has had a significant adverse impact on a number of financial institutions. We monitor the credit worthiness of our financial institutions. However, our procedures and the credit agencies ratings and reports cannot guarantee performance in these uncertain times.

Disclosure of Limitations

Because the information above included only those exposures that exist at September 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.

Evaluation of Disclosure Controls and Procedures

As of September 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 September 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 nine months ended September 30, 2008, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

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 third quarter 2008:

We improved controls over certain key financial statement spreadsheets that support all significant balance sheet and income statement accounts. Specifically, we enhanced the spreadsheet policy to provide additional clarification and guidance with regard to risk assessment and enforced controls over: 1) the security and integrity of the data used in the various spreadsheets, 2) access to the spreadsheets, 3) changes to spreadsheet functionality and the related approval process and documentation and 4) increased managements review of the spreadsheets.

In addition to accredited derivative training attended by key personnel, we created and documented a desktop procedure to: 1) ensure the completeness and accuracy of our derivative activities and 2) supplement our key controls previously existing in the process. Further, the desktop procedure provides for a more robust review of the derivative process. This procedure will continue to be enhanced throughout the fourth quarter of 2008.

In addition to the above changes, during the first quarter of 2008, we implemented the general ledger, accounts receivable, cash receipts, revenue, financial reporting, and joint interest billing modules as part of our new broader financial system. We had planned to implement a partnership distribution module in 2008, however, we currently do not expect this module to be in place until 2009. The new financial system will enhance operating efficiencies and provide more effective management of our business operations and processes. We believe the phased-in implementation approach we are taking reduces the risks associated with the new financial system implementation. We have taken the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps include documenting all new business process changes related to the new financial system; testing all new business processes on the new financial system; and conducting training related to the new business processes and to the new financial system software. We expect the implementation of the new financial system will strengthen the overall systems of internal controls due to enhanced automation and integration of related processes. We continue to modify the design and documentation of internal control processes and procedures related to the new financial system to supplement and complement existing internal controls over financial reporting. The system changes were developed 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.

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Remediation of Material Weaknesses in Internal Control

We, with oversight from the Audit Committee of our Board of Directors, have been addressing the material weaknesses disclosed in our 2007 Form 10-K and Item 4 of our subsequently filed Forms 10-Q. We believe, through the implementation of the above changes in internal controls over financial reporting, we will be able to remediate these known material weaknesses as of December 31, 2008. However, these control weaknesses will not be considered remediated until the changes in internal controls over financial reporting are operating effectively for a sufficient period of time and we have concluded, through testing, that these controls are operating effectively.

Until we have concluded that we have remediated these known material weaknesses in internal control over financial reporting, we have performed additional analysis and procedures in order to ensure that the accompanying condensed consolidated financial statements contained in this Form 10-Q were prepared in accordance with generally accepted accounting principles in the United States.

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 our 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 and the subsequent additional risk factor:

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.

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Recent disruptions in the global financial markets and the likely related economic downturn may further decrease the demand for oil and gas and the prices of oil and gas.

During the third quarter of 2008 and to date, prices for oil and gas decreased significantly. The well-publicized global financial market disruptions and the related economic downturn may additionally decrease demand for oil and gas and therefore lower oil and gas prices. If there is such an additional reduction in demand, the production of gas in particular may be in oversupply. We operate in a highly competitive industry, and certain competitors may have lower operating costs in such an environment. Furthermore, as a result of these disruptions in the financial markets, it is possible that in future years we would not be able to borrow sufficient funds to sustain or increase capital expenditures relative to anticipated 2008 and 2009 expenditures, should we wish to make expenditures at those levels. Such market conditions may also make it more difficult or impossible for us to finance acquisitions, through either equity or debt; acquisitions have historically been a major source of growth for us. We may also have difficulty finding partners to develop new drilling prospects and to build the pipeline systems needed to transport our gas. Any of the above factors could adversely affect our operating results.

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
July 1 - 31, 2008	10,073	$ 67.44	-	-
August 1-31, 2008	-	-	-	-
September 1-30, 2008	3,591	45.38	-	-
	13,664	61.65	-	-

Shares were purchased at fair market value based on the closing price on the date of purchase. Shares purchased were primarily to satisfy the statutory minimum tax withholding requirement related to our stock based compensation plans. We purchased 9,364 shares from members of our Board of Directors at a cost of $0.6 million (average price $67.65), all of which reflect shares withheld upon vesting of restricted stock to satisfy statutory minimum tax withholding obligations. Further, pursuant to the terms of our stock based compensation plans, we purchased 3,226 shares in a cashless exercise from our former chief executive officer at a cost of $0.1 million (average price $44.37). All shares purchased have been subsequently retired.

Items 3, 4 and 5 have been omitted as there is nothing to report.

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Item 6. Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1	Second Amended and Restated Certificate of Incorporation of Petroleum Development Corporation.	8-K	000-07246	3.1	07/23/2008	
4.1	Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and The Bank of New York.	8-K	000-07246	4.1	02/12/2008	
4.2	First Supplemental Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and the Bank of New York, incorporated by reference to Exhibit 4.2 to Form 8-K filed on February 12, 2008.	8-K	000-07246	4.2	02/12/2008	
4.3	Form of 12% Senior Note due 2018.	8-K	000-07246	4.2	02/12/2008	
10.1	Purchase Agreement dated as of February 1, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	02/07/2008	
10.2	Registration Rights Agreement dated as of February 8, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	02/12/2008	
10.3	Agreement with Steven R. Williams, Chairman of the Board of Directors.					X
10.4	Third Amendment to Amended and Restated Credit Agreement dated as of July 15, 2008, by and among Petroleum Development Corporation, certain of its subsidiaries, JP Morgan Chase Bank, N.A., BNP Paribas and various other banks.	8-K	000-07246	10.1	07/21/2008	
10.5	Fourth Amendment to Amended and Restated Credit Agreement dated as of July 18, 2008, by and among the Company, certain of its subsidiaries, JP	8-K	000-07246	10.2	07/21/2008	

	Morgan Chase Bank, N.A., BNP Paribas and various other banks.					
10.6	2005 Non-Employee Director Restricted Stock Plan Deferred Compensation Plan, amended and restated as of March 8, 2008.					X
10.7	2008 Long-Term Incentive Program (as amended for 2008).	8-K	000-07246	10.1	3/13/2008	
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.					X
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.					X
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.					X

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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: November 6, 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)