PETROLEUM DEVELOPMENT CORP
Form 10-Q
May 12, 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 March 31, 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 o No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,848,954 shares of the Company's Common Stock ($.01 par value) were outstanding as of May 1, 2008.

PETROLEUM DEVELOPMENT CORPORATION

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PART 1 – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

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

	March 31, 2008	December 31, 2007*
Assets		
Current assets:		
Cash and cash equivalents	$ 26,202	$ 84,751
Accounts receivable, net	60,699	60,024
Accounts receivable - affiliates	34,557	11,537
Fair value of derivatives	10,408	4,817
Other current assets	38,202	30,664
Total current assets	170,068	191,793
Properties and equipment, net	869,967	845,864
Other assets	35,432	12,822
Total assets	$ 1,075,467	$ 1,050,479
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 84,924	$ 88,502
Accounts payable - affiliates	4,401	3,828
Federal and state income taxes payable	996	901
Fair value of derivatives	57,518	6,291
Advances for future drilling contracts	40,911	68,417
Funds held for future distribution	57,223	39,823
Other accrued expenses	31,195	34,243
Total current liabilities	277,168	242,005
Long-term debt	203,000	235,000
Deferred income taxes	141,873	136,490
Other liabilities	73,141	40,699
Total liabilities	695,182	654,194
Commitments and contingencies		
Minority interest in consolidated limited liability company	743	759
Total shareholders' equity	379,542	395,526
Total liabilities and shareholders' equity	$ 1,075,467	$ 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 March 31, 2008	Three Months Ended March 31, 2007
Revenues:		
Oil and gas sales	$ 71,646	$ 34,016
Sales from natural gas marketing activities	23,325	21,987
Oil and gas well drilling operations	3,083	4,030
Well operations and pipeline income	2,352	3,298
Oil and gas price risk management loss, net	(42,310)	(5,645)
Other	3	226
Total revenues	58,099	57,912
Costs and expenses:		
Oil and gas production and well operations cost	18,132	9,035
Cost of natural gas marketing activities	22,121	21,512
Cost of oil and gas well drilling operations	78	564
Exploration expense	4,283	2,678
General and administrative expense	9,823	7,424
Depreciation, depletion and amortization	21,131	13,074
Total costs and expenses	75,568	54,287
Income (loss) from operations	(17,469)	3,625
Interest income	271	1,143
Interest expense	(4,932)	(831)
Income (loss) before income taxes	(22,130)	3,937
Provision (benefit) for income taxes	(8,202)	1,436
Net income (loss)	$ (13,928)	$ 2,501
Earnings (loss) per share		
Basic	$ (0.95)	$ 0.17
Diluted	$ (0.95)	$ 0.17
Weighted average common shares outstanding		
Basic	14,738	14,726
Diluted	14,738	14,854

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Cash flows from operating activities:		
Net income (loss)	$ (13,928)	$ 2,501
Adjustments to net income (loss) to reconcile to cash provided by (used in) operating activities:		
Deferred income taxes	(9,738)	(3,379)
Depreciation, depletion and amortization	21,131	13,074
Amortization of debt issuance costs	256	-
Accretion of asset retirement obligation	304	232
Exploratory dry hole costs	1,100	194
Expired and abandoned leases	442	53
Unrealized loss on derivative transactions	39,334	6,636
Changes in assets and liabilities	8,401	(52,532)
Other	1,487	483
Net cash provided by (used in) operating activities	$ 48,789	$ (32,738)
Cash flows from investing activities:		
Capital expenditures	(64,321)	(13,378)
Acquisitions	-	(201,488)
Decrease in restricted cash for property acquisition	-	191,452
Other	204	385
Net cash used in investing activities	(64,117)	(23,029)
Cash flows from financing activities:		
Proceeds from credit facility	42,000	70,000
Repayment of credit facility	(277,000)	(147,000)
Proceeds from senior notes	200,101	-
Payment of debt costs	(4,486)	-
Proceeds from exercise of stock options	367	152
Excess tax benefits from stock based compensation	154	-
Purchase of treasury stock	(4,357)	(135)
Net cash used in financing activities	(43,221)	(76,983)
Net decrease in cash and cash equivalents	(58,549)	(132,750)
Cash and cash equivalents, beginning of period	84,751	194,326
Cash and cash equivalents, end of period	$ 26,202	$ 61,576
Supplemental disclosure of cash flow information of cash payments for:		
Interest	$ 2,721	$ 2,205
Income taxes	2,774	24,781
Supplemental schedule of non-cash investing and financing activities:		

Change in deferred tax liability resulting from reallocation of acquisition purchase price	-	4,188
Changes in accounts payable related to the acquisitions of partnerships	-	668
Changes in accounts payable related to purchase of properties and equipment	(11,383)	17,563
Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	133	4,738
Changes in accounts payable related to debt costs	306	-

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
March 31, 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 for each of the applicable periods. 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 is 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 three months ended March 31, 2008, and the interim cash flows for the same interim period, are not necessarily indicative of the results to be expected for the full year or any other future period.

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

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

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

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. SFAS No. 159 permits entities to choose to measure, at fair value, many financial instruments and certain other items that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. As of March 31, 2008, we had not elected, nor do we intend, to measure additional financial assets and liabilities at fair value.

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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 do not expect the adoption of SFAS No. 160 to have a material effect on our financial statements and related disclosures.

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.

3. PROPERTIES AND EQUIPMENT

	March 31, 2008	December 31, 2007
	(in thousands)	
Properties and equipment, net:		

Oil and gas properties (successful efforts method of accounting)				
Proved	$	994,206	$	953,904
Unproved		41,938		41,023
Total oil and gas properties		1,036,144		994,927
Pipelines and related facilities		23,023		22,408
Transportation and other equipment		27,389		23,669
Land and buildings		13,898		11,303
Construction in progress (1)		-		2,929
		1,100,454		1,055,236
Accumulated depreciation, depletion and amortization ("DD&A")		(230,487)		(209,372)
	$	869,967	$	845,864

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

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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 in accordance with FSP No. 19-1, Accounting for Suspended Well Costs.

	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	4,483	7
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	-	-
Capitalized exploratory well costs charged to expense	(1,100)	(1)
Ending balance at March 31, 2008	$ 5,683	9

As of March 31, 2008, none of the nine suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year.

4. DERIVATIVE FINANCIAL INSTRUMENTS

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

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 March 31, 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 futures contracts and option contracts 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 and collars 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.

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We purchase puts and set collars and fixed-price swaps for our own and affiliate partnerships' production to protect against price declines in future periods while retaining some of the benefits of price increases.

With regard to our natural gas marketing activities, we enter into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to virtually eliminate our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market. We believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended, although they are currently below market due to the continual rises in energy prices.

The following table summarizes our open derivative positions as of March 31, 2008.

Open Derivative Positions
As of March 31, 2008
(dollars in thousands, except average price data)

						Positions maturing in 12 months of March 31, 2008			
Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Total Fair Value	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value - Current Portion
Total positions in effect for oil and gas sales (1)									
Natural gas	Cash settled option sales	44,910,000	$ 9.06	$ 406,865	$ (15,187)	28,670,000	$ 8.71	$ 249,760	$ (9,906)
Natural gas	Cash settled option purchases	44,910,000	7.05	316,566	10,968	28,670,000	7.65	219,266	3,805
Natural gas	Cash settled futures/swaps purchases	25,970,000	7.52	195,285	(34,241)	23,900,000	7.42	177,442	(33,147)
Oil	Cash settled futures/swaps purchases	1,170,000	84.79	99,208	(14,147)	620,000	84.48	52,375	(8,766)
Oil	Cash settled option sales	730,000	102.63	74,916	(7,052)	-	-	-	-
Oil	Cash settled option purchases	730,000	70.00	51,100	2,690	-	-	-	-
					$ (56,969)				$ (48,014)
Total positions in effect for natural gas marketing activities (2)									
Natural gas		245,030	$ 6.79	$ 1,663	$ 55	245,030	$ 6.79	$ 1,663	$ 55

	Cash settled futures/swaps purchases								
Natural gas	Cash settled futures/swaps sales	4,551,300	8.65	39,391	(6,225)	3,160,800	8.63	27,275	(5,655)
Natural gas	Physical purchases	4,351,300	8.93	38,856	7,429	2,960,800	8.96	26,528	6,548
Natural gas	Physical sales	35,030	9.45	331	(44)	35,030	9.45	331	(44)
					$ 1,215				$ 904

(1) The maximum term for the derivative positions is 35 months.
(2) The maximum term for the derivative positions is 45 months.

In addition to including the gross assets and liabilities related to our share of oil and gas production, the above tables and our condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into on behalf of our affiliate partnerships as the managing general partner. Our condensed consolidated balance sheets include the fair value of derivatives and a corresponding net receivable from the partnerships of $16.5 million at March 31, 2008, and a corresponding net receivable from the partnerships of $1.5 million at December 31, 2007.

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

	March 31, 2008	December 31, 2007
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	$ 10,408	$ 4,817
Other assets - long-term asset	10,734	193
	21,142	5,010
Fair value of derivatives - current liability	57,518	6,291
Other liabilities - long-term liability	19,378	93
	76,896	6,384
Net fair value of commodity based derivatives	$ (55,754)	$ (1,374)

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

	Three Months Ended March 31,			
	2008		2007	
Statement of income line item	Realized	Unrealized	Realized	Unrealized
	(in thousands, gains/(losses))			
Oil and gas price risk management gain (loss), net (1)	$ (2,411)	$ (39,899)	$ 580	$ (6,225)
Sales from natural gas marketing activities	486	(7,638)	1,097	(3,298)
Cost of natural gas marketing activities	66	8,203	(174)	2,887

(1) Represents net realized and unrealized gains and losses 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.

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

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

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

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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 March 31, 2008:

	Level 1	Level 2	Level 3	Total
Assets:				
Commodity based derivatives	$ 55	$ -	$ 21,087	$ 21,142
Liabilities				
Commodity based derivatives	(14,011)	$ -	(62,885)	$ (76,896)
Net fair value of commodity based derivatives	$ (13,956)	$ -	$ (41,798)	$ (55,754)

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

	Derivatives (1) (in thousands)
Balance at January 1, 2008	$ (2,368)
Total realized and unrealized gains or (losses), net:	
Included in oil and gas price risk management, net	(982)
Included in sales from natural gas marketing activities	(22)
Included in cost of natural gas marketing activities	(5)
Purchases, sales, issuances and settlements, net	(38,421)
Balance at March 31, 2008	$ (41,798)
Total gains (losses) attributable to the change in unrealized gain (loss), net relating to assets still held as of March 31, 2008:	
Included in oil and gas price risk management, net	$ (1,009)
Included in sales from natural gas marketing activities	-
Included in cost of natural gas marketing activities	-
Total	$ (1,009)

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

6. LONG-TERM DEBT

Long-term debt consists of the following:

	March 31, 2008	December 31, 2007
	(in thousands)	
Credit facility	$ -	$ 235,000
12% Senior notes due 2018	203,000	-

Total long-term debt	$ 203,000	$ 235,000

Credit facility

We have a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended, dated as of November 4, 2005, with an activated commitment of $234.1 million as of March 31, 2008. The credit facility, through a series of amendments, includes commitments from: Wachovia Bank N.A.; Bank of Oklahoma; Allied Irish Banks p.l.c.; Guaranty Bank, FSB; Royal Bank of Canada; and The Royal Bank of Scotland, plc. The maximum allowable commitment under the current credit facility is $400 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. We are required to pay a commitment fee of ..25% to .375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus ..5%. ABR borrowings are assessed an additional margin spread up to ..375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%, based upon the outstanding balance under the credit facility. The credit agreement requires, among other things, the maintenance of certain working capital and tangible net worth ratios. No principal payments are required until the credit agreement expires on November 4, 2010.

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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 March 31, 2008, our credit facility was undrawn compared to $235 million as of December 31, 2007. The borrowing rate on the outstanding balance was 7.07% as of December 31, 2007. Future amounts outstanding under the credit facility will be secured by substantially all of our properties. We were in compliance with all covenants at March 31, 2008, and expect to remain in compliance throughout 2008.

12% Senior Notes Due 2018

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

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company. We were in compliance with all covenants as of March 31, 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.

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.

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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. If we fail to comply with certain obligations under the registration rights agreement, a situation that is not expected to occur, we will be required to pay liquidated damages to the holders of the notes in an amount equal to $.05 per week per $1,000 principal amount held by the holder for the first 90-day period immediately following the default. The amount of the liquidated damages increases by an additional $.05 per week per $1,000 principal amount held by the holder with respect to each subsequent 90-day period until the default has been cured, up to a maximum amount of liquidated damages of $.20 per week per $1,000 principal amount held by the holder. On April 24, 2008, we filed the related registration statement on Form S-4. As of the date of this filing, the registration statement has not yet been declared effective.

7. COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. We are a party to a pipeline expansion agreement with an unrelated third party, which is also currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to invest a minimum of $65 million to develop specified acreage in the Wattenberg Field, during a three-year period ending December 31, 2009. Such capital spending will include costs to drill new wells and the cost to recomplete existing wells in this area. Should we not meet the minimum commitment by December 31, 2009, we will be required to pay liquidated damages of $2 million, prorated based on our actual capital investment made to date. As of March 31, 2008, our total capital expenditures pursuant to the agreement were $41.7 million, resulting in a maximum potential obligation for liquidating damages of $0.7 million.

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 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 March 31, 2008, no wells had been drilled pursuant to this agreement.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to our financial ability to do so. The maximum annual repurchase obligation as of March 31, 2008, was approximately $7 million. We have adequate liquidity to meet this obligation. During the first three months of 2008 and 2007, we paid $0.8 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. As of March 31, 2008, commitments for these two separate contracts expire in August 2009 and July 2010. As of March 31, 2008, we have an outstanding minimum commitment for $6 million and an outstanding maximum commitment for $22.9 million.

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

On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells operated by us in the State of Colorado (the "Droegemueller Action"). The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007, and on July 10, 2007, we filed our answer and affirmative defenses. A second similar Colorado class action suit was filed against the Company in the U.S. District Court for the District of Colorado on December 3, 2007, by Ted Amsbaugh et al. This case was consolidated with the Droegemueller Action above on January 28, 2008. On February 29, 2008, the court approved a 90 day stay in proceedings while the parties pursue mediation of the matter. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, we are unable to predict the ultimate outcome of this suit at this time. We believe that the ultimate outcome of the proceedings will not have a material adverse effect on our financial condition or results of operations.

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Litigation similar to the preceding actions has been commenced against several other companies in other jurisdictions where we conduct business. While our business model differs from that of the parties involved in such other litigation, and although the Company has not been named as a party in such other litigation, there can be no assurance that the Company will not be named as a party to such other litigation in the future.

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

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

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

Derivative Contracts. We would be 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 March 31, 2008	2007
	(in thousands)	
Total stock-based compensation expense	$ 1,792 (1)	$ 483
Income tax benefit	(691)	(186)
Net income impact	$ 1,101	$ 297

(1) Includes $1.1 million related to the separation agreement with our former president.

Stock Option Awards. We granted stock options in previous years under several 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 option awards for the three months ended March 31, 2008 and 2007.

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The following table provides a summary of our stock option award activity for the three months ended March 31, 2008:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2007	51,567	$ 33.55	6.4	$ 1.3
Exercised	(8,829)	41.51		0.2
Outstanding at March 31, 2008	42,738	31.90	5.9	1.6
Vested and expected to vest at March 31, 2008	37,512	30.39	5.6	1.5
Exercisable at March 31, 2008	29,283	26.89	5.0	1.2

Total unrecognized stock-based compensation cost related to stock options expected to vest was $0.1 million as of March 31, 2008. This cost is expected to be recognized over a weighted average period of 1.5 years. As of March 31, 2008, stock-based compensation related to stock options not expected to vest and unamortized was $0.1 million.

Restricted Stock Awards

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

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, generally over four years.

The following table sets forth the changes in non-vested time-based awards for the three months ended March 31, 2008:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2007	171,845	$ 44.38
Granted	56,497	67.51
Vested	(26,507)	50.36
Forfeited	(2,891)	41.81
Non-vested at March 31, 2008	198,944	$ 51.04

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized as of March 31, 2008, is $8.1 million. This cost is expected to be recognized over a weighted-average period of 2.8 years. As of March 31, 2008, stock-based compensation related to time-based awards not expected to vest and unamortized was $0.6 million.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years for market-based awards. 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.

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

	Three Months Ended March 31, 2008	2007
Expected term of award	3 years	3 years
Risk-free interest rate	2.4%	4.7%
Volatility	47.0%	44.0%

The following table sets forth the changes in non-vested marked-based awards for the three months ended March 31, 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 March 31, 2008	72,683	$ 43.64

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized as of March 31, 2008, is $1.3 million. This cost is expected to be recognized over a weighted-average period of 2.8 years. As of March 31, 2008, stock-based compensation related to market-based awards not expected to vest and unamortized was $1.6 million.

9. INCOME TAXES

We evaluate the estimated annual effective income tax rate on a quarterly basis based on current and forecasted business results and enacted tax laws. This estimated annual effective tax rate is updated 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, inclusive of discrete items, was 37.1% for the first quarter of 2008, relatively unchanged from 36.5% for the first quarter of 2007. Our rate differs from the combined federal and state statutory rates (net of the federal benefit), primarily due to certain business incentives such as percentage depletion and the domestic production deduction. Discrete items were not significant.

As of March 31, 2008, we had a gross liability for uncertain tax benefits of $0.9 million, of which $0.4 million, if recognized, would affect our effective tax rate. There were no significant changes to the calculation since year end 2007.

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 amount noted above, that is accrued for uncertain tax benefits in our current tax liability on our balance sheet, to be reduced during the next year.

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

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10. EARNINGS PER SHARE

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

	Three Months Ended March 31, 2008	2007
	(in thousands, except per share data)	
Weighted average common shares outstanding	14,738	14,726
Dilutive effect of share-based compensation: (1)		
Unamortized portion of restricted stock	-	63
Stock options	-	60
Non employee director deferred compensation	-	5
Weighted average common and common equivalent shares outstanding	14,738	14,854
Net income (loss)	$ (13,928)	$ 2,501
Basic earnings (loss) per common share	$ (0.95)	$ 0.17
Diluted earnings (loss) per common share	$ (0.95)	$ 0.17

(1) For the three months ended March 31, 2008, 70, 38 and 6 average common share equivalents related to unvested restricted stock, stock options and shares related to non employee director deferred compensation, respectively, were excluded from the computation of diluted net loss per share as their effect was anti-dilutive. For the three months ended March 31, 2007, there were no common share equivalents excluded from the computation of diluted net income per share.

11. BUSINESS SEGMENTS

Our operating activities can be divided into four major segments: oil and gas sales, natural gas marketing, oil and gas well drilling operations, and well operations and pipeline income. We drill natural gas wells for Company-sponsored drilling partnerships and retain an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. We own an interest in approximately 4,400 wells from which we sell our oil and gas production from our working interests in the wells. We charge Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the three months ended March 31, 2008 and 2007 is presented below.

	Three Months Ended March 31, 2008	2007
	(in thousands)	
Revenues:		
Oil and gas sales (1)	$ 29,336	$ 28,371
Natural gas marketing	23,325	21,987
Oil and gas well drilling operations	3,083	4,030
Well operations and pipeline income	2,352	3,298
Unallocated amounts	3	226
Total	$ 58,099	$ 57,912

Segment income (loss) before income taxes:		
Oil and gas sales (1)(2)	$ (11,994)	$ 5,839
Natural gas marketing	1,332	679
Oil and gas well drilling operations	3,005	3,467
Well operations and pipeline income (3)	592	1,234
Unallocated amounts (4)	(15,065)	(7,282)
Total	$ (22,130)	$ 3,937

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(1) Includes oil and gas price risk management loss, net of $42.3 million and $5.6 million for the three months ended March 31, 2008 and 2007, respectively.
(2) Includes $4.3 million and $2.7 million in exploration costs and $20.3 million and $12.4 million of DD&A expense for the three months ended March 31, 2008 and 2007, respectively.
(3) Includes $0.4 million and $0.5 million of DD&A expense for the three months ended March 31, 2008 and 2007, respectively.
(4) Includes general and administrative expense, interest income, interest expense, and DD&A expense of $0.5 million and $0.2 million for the three months ended March 31, 2008 and 2007, respectively.

	March 31, 2008	December 31, 2007
	(in thousands)	
Segment assets:		
Oil & gas sales	$ 882,469	$ 862,237
Natural gas marketing	39,543	40,269
Oil and gas well drilling operations	8,233	4,959
Well operations and pipeline income	54,814	26,156
Unallocated amounts	90,408	116,858
Total	$ 1,075,467	$ 1,050,479

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

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This current 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, and the operating hazards attendant 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.

Management Overview

Net loss for the three months ended March 31, 2008, was $13.9 million compared to net income of $2.5 million for the same prior year period. The primary reason for the loss during the first quarter of 2008 compared to 2007 was due to the unrealized losses on derivatives of $39.9 million compared to $6.2 million for the same prior year period. Rapid increases during the first quarter of 2008 to record high oil prices and sharp increases in natural gas prices from

December 31, 2007, to March 31, 2008, along with our increased use of derivative contracts and specifically more fixed price swaps caused the increase in realized and unrealized losses in oil and gas price risk management loss, net. See Oil and Gas Price Risk Management Loss, Net discussion below for a detailed discussion of realized and unrealized losses on oil and gas derivative activity. The major offsetting factors, which somewhat mitigated the non-cash unrealized derivative loss, were the effect on oil and gas sales due to significantly increased production and commodity prices realized during the period.

Our total oil and natural gas production increased by 3.1 Bcfe or approximately 59% during the quarter ended March 31, 2008, compared to the quarter ended March 31, 2007. During this same time period, the average sales price per Mcfe increased by approximately 32% from $6.38 per Mcfe during the quarter ended March 31, 2007, to $8.45 per Mcfe during the quarter ended March 31, 2008. See our oil and gas production table below under Oil and Gas Sales.

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Total revenues for the three months ended March 31, 2008, were $58.1 million compared to $57.9 million for the same prior year period. The two offsetting items for the quarter ended March 31, 2008, compared with 2007 were oil and gas sales and oil and gas price risk management loss, net. Our total oil and gas sales increased from $34 million for the three months ended March 31, 2007, to $71.6 million for the three months ended March 31, 2008, an increase of $37.6 million or 111%. The increase was driven by an increase in production of 59% and an increase in realized oil and natural gas prices of 32%.

The $37.6 million increase in oil and gas sales was almost entirely offset by an increase in oil and gas price risk management loss, net of $36.7 million for the three months ended March 31, 2008, compared with the prior year first quarter. Of the $42.3 million oil and gas price risk management loss for the first quarter of 2008, $39.9 million resulted from non-cash unrealized losses resulting from significant increases in oil and gas commodity prices from December 31, 2007, to March 31, 2008, on open derivative positions.

Costs and expenses for the three months ended March 31, 2008, were $75.6 million compared to $54.3 million for the same prior year period, an increase of $21.3 million or 39.2%. The increase was primarily the result of increases in oil and gas production and well operations cost, general and administrative expense and depreciation, depletion and amortization.

The 59% or 3.1 Bcfe increase in production for the first quarter of 2008 compared to the same prior year period was the primary contributor to the increases in oil and gas production and well operations cost and depreciation, depletion and amortization. The increase in general and administrative expense is primarily due to expenses associated with the separation agreement executed with our former president upon his resignation.

While we benefit significantly from the rising energy prices in our oil and gas sales, the rising energy prices bring about inflationary factors that affect our costs and expenses. The increase in energy prices has affected demand for drilling and completion services, land acquisitions, and the cost of experienced industry personnel. The cost of steel used for tubular goods and surface equipment has increased dramatically over the past several years and represents approximately 20% to 30% of the total cost of a new well. We expect this inflationary trend to continue as energy prices rise. We consume great quantities of fuel in the use of drilling rigs, service rigs, vehicles used for hauling materials, such as surface casing, tubular goods and water, as well as, vehicles used for well tending and general operations.

See the following discussion of results of operations describing in more detail the components of revenues and expenses and, where significant, providing an analysis of changes year over year and the cause or underlying reason for such change.

Results of Operations

Revenues

Oil and Gas Sales

	Three Months Ended March 31,		Change	
	2008	2007	Amount	Percent
	(dollars in thousands)			
Oil and gas sales	$ 71,646	$ 34,016	$ 37,630	110.6%

Oil and gas sales from our producing properties for the three months ended March 31, 2008, were $71.6 million compared to $34.0 million for the same prior year period, an increase of $37.6 million or approximately 111%. The increase was due to increased volumes of natural gas and oil along with increased average sales prices of natural gas and oil.

Increased volumes of oil and natural gas produced contributed $25.1 million to oil and gas sales revenue for the current quarter and significantly increased commodity prices contributed the remaining $12.5 million increase in oil and gas sales revenue, for a total increase in oil and natural gas sales revenue of $37.6 million for the first quarter of 2008 compared to the same prior year period. The volume of natural gas sold for the three months ended March 31, 2008, was 6.9 Bcf at an average sales price of $7.33 per Mcf compared to 4.1 Bcf at an average sales price of $6.05 per Mcf for the three months ended March 31, 2007. Oil sales were 255,500 barrels at an average sales price of $81.14 per barrel for the three months ended March 31, 2008, compared to 199,500 barrels at an average sales price of $45.06 per barrel for the three months ended March 31, 2007. The increase in oil and natural gas volumes resulted from acquisitions of producing oil and gas properties and a significant increase in the number of wells drilled for our own account over the past year.

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Oil and Gas Production. Our oil and natural gas production by area of operations along with average sales price (excluding derivative gains/losses) is presented below:

	Three Months Ended March 31,								
	2008			2007			Change		
	Oil (Bbls)	Natural Gas (Mcf)	Natural Gas Equivalent (Mcfe)	Oil (Bbls)	Natural Gas (Mcf)	Natural Gas Equivalent (Mcfe)	Oil	Natural Gas	Total
Production									
Appalachian Basin	1,096	967,620	974,196	1,374	609,397	617,641	-20%	59%	58%
Michigan Basin	823	379,437	384,375	815	420,887	425,777	1%	-10%	-10%
Rocky Mountain Region	253,533	5,599,765	7,120,963	197,350	3,105,669	4,289,769	28%	80%	66%
Total	255,452	6,946,822	8,479,534	199,539	4,135,953	5,333,187	28%	68%	59%

	Three Months Ended March 31,								
	2008			2007			Change		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total	Oil	Natural Gas	Total
	(dollars in thousands, except average price)								
Sales									
Appalachian Basin	$ 97	$ 8,138	$ 8,235	$ 69	$ 4,052	$ 4,121	41%	101%	100%
Michigan Basin	79	2,895	2,974	40	2,568	2,608	98%	13%	14%
Rocky Mountain Region	20,551	39,886	60,437	8,882	18,408	27,290	131%	117%	121%
Total	$ 20,727	$ 50,919	$ 71,646	$ 8,991	$ 25,028	$ 34,019	131%	103%	111%
Average Sales Price									
(Oil - per Bbl, Natural Gas - per Mcf, Total - per Mcfe)									
Appalachian Basin	$ 88.71	$ 8.41	$ 8.45	$ 50.59	$ 6.65	$ 6.67	75%	26%	27%
Michigan Basin	96.03	7.63	7.74	49.02	6.10	6.12	96%	25%	26%
Rocky Mountain Region	81.08	7.13	8.49	45.02	5.92	6.36	80%	20%	33%
Total	$ 81.14	$ 7.33	$ 8.45	$ 45.06	$ 6.05	$ 6.38	80%	21%	32%

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

Oil and 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 and other markets as shown in the graph below. The expansion in January 2008 of the Rockies Express pipeline, a major interstate pipeline constructed and operated by a non-affiliated entity, is the primary reason for the narrowing of the NYMEX/Colorado Interstate Gas ("CIG") gap from November 2007 and forward. Once the third phase of the expansion of the Rockies Express is completed in 2009, the pipeline capacity is expected to increase by 64% to 1.8 Bcf/per day of natural gas from the region. Like most producers in the region, we rely on major interstate pipeline companies to construct these facilities to increase pipeline capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is also driven strongly by supply and demand relationships. In the Rocky Mountain Region in 2007, and the first quarter of 2008, the oil prices we received were below the NYMEX oil market due to supply competition from Rocky Mountain and Canadian oil that has driven down market prices. Beginning in the middle of the second quarter of 2008, through the end of 2010, we have contracted the majority of our oil sales at a price with a smaller spread below NYMEX.

Rocky Mountain Region Pricing. 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. 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.

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The graph below identifies the actual NYMEX and CIG natural gas prices by month from January 2006 through April 2008 and the forward curve for natural gas prices from May 2008 through November 2009 as of April 21, 2008. The forecasted prices in the graph have been derived from the sources indicated and represent, in our opinion, a reasonable view of the possible movement of the CIG and NYMEX natural gas prices over the next nineteen months. However, because the prices given in the graph represent forecasts of future matters and are subject to future events which we cannot predict, we can give no assurance that these forecasted prices will be as they are presented in the graph. An investor should therefore not rely on these forecasted prices in making an investment decision regarding our stock.

*Source: Derived from various sources including FutureSource, Inside Federal Energy Regulatory Commission's ("FERC") Gas Market Report and ClearPort Trading.

While the above graph shows a large differential between 2007 NYMEX and CIG pricing, the gap began narrowing in November 2007 and has continued to narrow. As of April 21, 2008, the negative price differential between NYMEX and CIG for 2008 has narrowed to $1.93 from $3.38 average for the fourth quarter of 2007. Although 80.6% of our first quarter 2008 natural gas production came from the Rocky Mountain Region, 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 quarter ended March 31, 2008. The pricing basis is the index that most closely relates to the contract under which the oil and natural gas is sold. As it indicates, 40% of our natural gas sales are derived from the CIG Index and other similarly priced Rocky Mountain pipelines.

Energy Market Exposure
For the Three Months Ended March 31, 2008

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	Rocky Mountain (CIG, et. al.)	Gas	40.0%
NECO	Mid Continent (Panhandle Eastern)	Gas	26.0%
Colorado/North Dakota	NYMEX	Oil	16.0%
Appalachian	NYMEX	Gas	11.0%
Michigan	Mich-Con/NYMEX	Gas	5.0%
Wattenberg	Colorado Liquids	Gas	2.0%
			100.0%

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Natural Gas Marketing Activities

	Three Months Ended March 31, 2008	2007	Change Amount	Percent
	(dollars in thousands)			
Sales from natural gas marketing activities	23,325	21,987	1,338	6.1%

The increase in sales from natural gas marketing activities in 2008 is primarily due to an increase in prices and volumes sold, partially offset by a $4.3 million increase in unrealized losses on derivative transactions from a $3.3 million loss in 2007 to a $7.6 million loss in 2008.

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.

Oil and Gas Price Risk Management Loss, Net

	Three Months Ended March 31, 2008	2007	Change Amount	Percent
	(dollars in thousands)			
Oil and gas price risk management:				
Realized gain (loss):				
Oil	$ (1,306)	$ (52)	$ (1,254)	*
Natural gas	(1,105)	632	(1,737)	*
Total realized gain (loss)	(2,411)	580	(2,991)	*
Unrealized loss	(39,899)	(6,225)	(33,674)	*
Oil and gas price risk management loss, net	$ (42,310)	$ (5,645)	$ (36,665)	*

*Represents percentages in excess of 250%.

The rapid increases during the first quarter of 2008 to record high oil prices and sharp increases in natural gas prices from December 31, 2007, to March 31, 2008, along with our increased use of derivative contracts and specifically more fixed price swaps caused the increase in realized and unrealized losses in oil and gas price risk management loss, net. The $39.9 million in unrealized losses for the three months ended March 31, 2008, is the fair value of the derivative positions as of March 31, 2008, less the fair value as of December 31, 2007, and includes all open positions as of March 31, 2008, for the entire period from April 2008 until the expiration of the last position, which is February 2011. The unrealized loss is a non-cash item in the first quarter of 2008 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.

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

Oil and Gas Derivative Activities. Because of uncertainty surrounding oil and natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through February 2011, 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 March 31, 2008, we averaged natural gas volumes sold of 2.3 Bcf per month and oil sales of 85,000 barrels per month.

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The following table sets forth our derivative positions in effect as of May 12, 2008, on our share of production by area.

				Floors		Ceilings		Swaps (Fixed Prices)	
Commodity/ Index/ Area	Month Set	Month	Gross Monthly Quantity Gas -MMbtu Oil -Bbls	Net Monthly Quantity Gas -MMbtu Oil -Bbls	Floor Price	Net Monthly Quantity Gas -MMbtu Oil -Bbls	Ceiling Price	Net Monthly Quantity Gas-MMbtu Oil -Bbls	Price
Natural Gas - Colorado Interstate Gas (CIG) Based Derivatives									
Piceance Basin									
	Feb-08	Apr 08 - Oct 08	750,000	-	$ -	-	$ -	454,650	$ 7.05
	Jan-08	Apr 08 - Oct 08	630,000	-	-	-	-	381,906	6.54
	Apr-08	Nov 08 - Mar 09	570,000	-	-	-	-	345,534	7.76
	Feb-08	Nov 08 - Mar 09	340,000	206,108	7.00	206,108	9.70	-	-
	Feb-08	Nov 08 - Mar 09	340,000	-	-	-	-	206,108	8.18
	Jan-08	Apr 09 - Oct 09	570,000	345,534	5.75	345,534	8.75	-	-
	Mar-08	Apr 09 - Oct 09	560,000	339,472	5.75	339,472	9.05	-	-
Wattenberg Field									
	Feb-08	Apr 08 - Oct 08	450,000	-	-	-	-	321,480	7.05
	Jan-08	Apr 08 - Oct 08	290,000	-	-	-	-	211,460	6.54
	Apr-08	Nov 08 - Mar 09	320,000	-	-	-	-	241,460	7.76
	Feb-08	Nov 08 - Mar 09	180,000	133,590	7.00	133,590	9.70	-	-
	Feb-08	Nov 08 - Mar 09	180,000	-	-	-	-	133,590	8.18
	Jan-08	Apr 09 - Oct 09	320,000	241,460	5.75	241,460	8.75	-	-
	Mar-08	Apr 09 - Oct 09	290,000	218,600	5.75	218,600	9.05	-	-
Natural Gas - Panhandle Based Derivatives									
NECO									
	Feb-08	Apr 08 - Oct 08	180,000	-	-	-	-	180,000	7.45
	Jan-08	Apr 08 - Oct 08	120,000	-	-	-	-	120,000	6.80
	Apr-08	Nov 08 - Mar 09	110,000	-	-	-	-	110,000	8.09
	Feb-08	Nov 08 - Mar 09	80,000	80,000	7.25	80,000	10.05	-	-
	Feb-08	Nov 08 - Mar 09	80,000	-	-	-	-	80,000	8.44
	Jan-08	Apr 09 - Oct 09	110,000	110,000	6.00	110,000	9.70	-	-
	Mar-08	Apr 09 - Oct 09	130,000	130,000	6.25	130,000	11.75	-	-
Natural Gas - NYMEX Based Derivatives									
Appalachian and Michigan Basins									
	Feb-08	Apr 08 - Oct 08	170,000	-	-	-	-	124,763	8.33
	Feb-08	Apr 08 - Oct 08	170,000	-	-	-	-	124,763	8.58
	Mar-08	Nov 08 - Mar 09	170,000	124,763	9.00	124,763	11.32	-	-
	Feb-08	Nov 08 - Mar 09	100,000	73,390	8.40	73,390	13.05	-	-
	Feb-08	Nov 08 - Mar 09	100,000	-	-	-	-	73,390	9.62
	Jan-08	Apr 09 - Oct 09	170,000	124,763	6.75	124,763	12.45	-	-

Mar-08	Apr 09 - Oct 09	170,000	124,763	7.50	124,763	13.25	-	-
Feb-08	Mar 08 - Feb 11	90,000	-	-	-	-	90,000	8.62
May-08	Apr 09 - Mar 12	60,000	-	-	-	-	44,034	9.89
Oil - NYMEX Based								
Wattenberg Field								
Oct-07	Apr 08 - Dec 08	48,667	-	-	-	-	31,741	84.20
May-08	Jun 08 - Dec 08	36,686	-	-	-	-	23,927	108.05
Jan-08	Jan 09 - Dec 09	30,417	-	-	-	-	19,838	84.90
Jan-08	Jan 09 - Dec 09	30,417	-	-	-	-	19,838	85.40
May-08	Jan 10 - Dec 10	12,167	-	-	-	-	7,935	117.35
May-08	Jan 10 - Dec 10	30,417	-	-	-	-	19,838	92.74
May-08	Jan 10 - Dec 10	30,417	-	-	-	-	19,838	93.17

We use oil and natural gas commodity derivative instruments to manage price risk for ourselves as well as our sponsored drilling partnerships. We set these instruments for ourselves and the partnerships jointly by area of operation. As volumes produced change, the mix between PDC and the partnerships will change. The gross volumes in the above table reflect the total volumes hedged for ourselves and the partnerships jointly by area of operation. The above table reflects such revisions necessary to present our positions in effect as of March 31, 2008.

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Costs and Expenses

Oil and Gas Production and Well Operations Cost

Oil and gas production and well operations costs for the three months ended March 31, 2008 and 2007, are presented below.

	Three Months Ended March 31, 2008	2007	Change Amount	Percent
	(dollars in thousands, except per Mcfe)			
Oil and gas production and well operations cost	$ 18,132	$ 9,035	$ 9,097	100.7%
Per Mcfe	$ 2.14	$ 1.69	$ 0.45	26.6%

The increase in oil and gas production and well operations cost for the year was primarily attributable to the 59% increase in production volumes and the increased number of wells and pipeline systems we operate. Lifting costs per Mcfe increased approximately 50% from $1.15 per Mcfe in the first quarter of 2007 to $1.72 per Mcfe in 2008. Included in our lifting costs are production taxes which are based upon the sales prices of the oil and natural gas sold. Since the average prices per Mcfe increased from $6.38 in the first quarter of 2007 to $8.45 for the first quarter of 2008, $.15 per Mcfe of the $.57 per Mcfe increase in lifting costs is due to the production taxes on higher oil and gas sales.

In addition to increased production, the increase in costs is also attributable to increased 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 the lifting cost of our production, 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.

Natural Gas Marketing Activities

Cost of natural gas marketing activities for the three months ended March 31, 2008 and 2007, is presented below.

	Three Months Ended March 31, 2008	2007	Change Amount	Percent
	(dollars in thousands)			
Cost of natural gas marketing activities	$ 22,121	$ 21,512	$ 609	2.8%

The increase in the cost of natural gas marketing activities in 2008 was primarily due to an increase in prices and volumes purchased for resale, primarily offset with a $5.3 million increase in unrealized gains on derivative transactions, from a $2.9 million gain in 2007 to an $8.2 million gain in 2008.

Exploration Expense

Exploration expense for the three months ended March 31, 2008 and 2007, is presented below.

	Three Months Ended March 31,		Change	
	2008	2007	Amount	Percent
	(dollars in thousands)			
Exploration expense	$ 4,283	$ 2,678	$ 1,605	59.9%

The increase in exploration expense is primarily due to an increase in staffing costs, including the use of consultants, along with additional seismic work and an increase in lease expense.

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General and Administrative Expense

General and administrative expense for the three months ended March 31, 2008 and 2007, is presented below.

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	Change Amount	Change Percent
	(dollars in thousands, except per Mcfe)			
General and administrative expense	$ 9,823	$ 7,424	$ 2,399	32.3%
Per Mcfe	$ 1.16	$ 1.39	$ (0.23)	-16.5%

The increase in general and administrative expense for the three months ended March 31, 2008, was the result of expenses related to a separation agreement for our former president in the amount of $3.2 million during the first quarter of 2008. Although general and administrative expense increased $2.4 million from 2007 to 2008, the rate per Mcfe declined from $1.39 per Mcfe to $1.16 per Mcfe.

Depreciation, Depletion, and Amortization

DD&A for the three months ended March 31, 2008 and 2007, is presented below.

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	Change Amount	Change Percent
	(dollars in thousands, except per Mcfe)			
Depreciation, depletion and amortization	$ 21,131	$ 13,074	$ 8,057	61.6%
Per Mcfe	$ 2.49	$ 2.45	$ 0.04	1.6%

The 59% higher production volumes realized in 2008 resulted in an $8.1 million increase in DD&A expense in the quarter ended March 31, 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 March 31, 2008	Three Months Ended March 31, 2007
	(per Mcfe)	
Appalachian Basin	$ 1.47	$ 1.27
Michigan Basin	1.30	1.26
Rocky Mountain Region:		
Wattenberg Field (1)	3.37	2.90
Piceance Basin	1.81	2.21
NECO	1.29	1.40

(1) This field contains 93.9% and 87.5% of our oil production for the quarters ended March 31, 2008 and 2007, respectively.

The weighted average DD&A rate for oil and gas properties increased to $2.33 per Mcfe for the three months ended March 31, 2008 from $2.32 per Mcfe for the same period in 2007. Although the overall DD&A rate increased only by $.01 per Mcfe from the first quarter of 2007 to the first quarter of 2008, the upward revision in our reserve report at December 31, 2007, due to higher commodity pricing, partially offset by increased operation costs, lowered our DD&A rate per Mcfe at about the same proportion that the higher cost of well drilling, completion and equipping of new wells increased the DD&A rate. As reflected in the above table of field DD&A rates, this overall increase of $.01 per Mcfe varied greatly among our major fields depending on whether the increase in reserves out weighted the increase in costs. DD&A expense for non-oil and gas properties, which are not included in the above table, increased to $1.4 million in 2008 from $0.7 million in 2007, and consist primarily of the Garden Gulch Road, a new integrated oil and gas financial reporting system and equipment acquired in our October 2007 acquisition.

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Non-operating Income/Expense

Non-operating income and expense for the three months ended March 31, 2008 and 2007, are presented below.

	Three Months Ended March 31,		Change	
	2008	2007	Amount	Percent
	(dollars in thousands)			
Non-operating income (expense):				
Interest income	$ 271	$ 1,143	$ (872)	-76.3%
Interest expense	$ (4,932)	$ (831)	$ (4,101)	493.5%

The decrease in interest income for the quarter is a result of lower cash balances earning interest at lower rates compared to the same period last year, primarily due to the $353.6 million in cash proceeds from the sale of undeveloped leaseholds in July 2006; the proceeds were earning interest until reinvested in oil and gas properties in mid January 2007. The increase in interest expense in 2008 was due to significantly higher average outstanding balances of our credit facility and the 12% senior notes, offset by capitalized construction period interest of $0.6 million in 2008 and $0.5 million in 2007. We utilize our daily cash balances to reduce the line of credit borrowings, lowering the cost of interest.

Provision for Income Taxes

The effective income tax rate for the current quarter was 37.1%, relatively unchanged from 36.5% in the same prior year quarter.

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. We have a $234.1 million syndicated revolving bank facility which matures on November 4, 2010. On February 8, 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018 for net proceeds received of approximately $196 million, which we used to repay our bank credit facility.

As of March 31, 2008, we have access to all of the $234.1 million facility as it was undrawn. Additionally, we believe that our continued drilling activities will allow us, through our permitted borrowing base redeterminations, to increase the borrowing capacity of the credit facility as additional properties are developed. Based on near-term cash flow projections, the discretionary nature of our capital budget, our bank credit facility capacity and the demonstrated ability to raise capital in bank, private and public markets, we believe that we have sufficient liquidity and capital resources to conduct our business and operations as well as remain compliant with our debt covenants throughout 2008.

Capital Expenditures

We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Our 2008 capital expenditure budget was initially approved at $255 million: $194 million for drilling and development; $50 million for exploratory drilling, land acquisitions and seismic activities; and $11 million for other capital expenditures. With higher than anticipated oil and natural gas prices and resulting increases in cash flows from operations, our Board of Directors has approved an increase in our capital expenditure budget of $40 million for a total of $295 million. The entire $40 million increase was designated for additional development drilling in our Grand Valley field of our Rocky Mountain Region. 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 annual 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 three months ended March 31, 2008, were 111% higher than the three months ended March 31, 2007, resulting from a 32% increase in average oil and natural gas prices and a 59% increase in oil and natural gas production. While a decline in oil and natural gas prices would affect the amount of cash flow that would be generated from operations, we had oil fixed-price swaps, as of May 12, 2008, that we estimate will largely offset price changes for approximately 70% of our expected oil production and fixed price swaps and collars on 69% of our expected natural gas production for the remainder of 2008, thereby reducing the risk of significant declines for a substantial portion of our 2008 cash flow. The remaining 30% and 31% of estimated 2008 oil and natural gas production, respectively, is 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 May 12, 2008, are detailed above in Results of Operations – Oil and Gas Price Risk Management Loss, 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 three months ended March 31, 2008, was $57 million, largely related to cash used in drilling activities.

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

Drilling Activity

The following table summarizes our development and exploratory drilling activity for the first three months ended March 31, 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 March 31,			
	2008		2007	
	Gross	Net	Gross	Net
Development				
Productive (1)	92.0	58.8	54.0	38.4
Dry	-	-	2.0	1.4
Total development	92.0	58.8	56.0	39.8
Exploratory				
Productive (1)	-	-	-	-
Dry	2.0	2.0	2.0	0.7
Pending determination	7.0	7.0	3.0	1.0
Total exploratory	9.0	9.0	5.0	1.7
Total Drilling Activity	101.0	67.8	61.0	41.5

(1) As of March 31, 2008, a total of 161 productive wells, 84 drilled in 2008 and 77 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 March 31,			
	2008		2007	
	Gross	Net	Gross	Net
Rocky Mountain Region:				
Wattenberg	45.0	21.7	30.0	13.8
Piceance	21.0	13.4	16.0	14.1
NECO	29.0	26.6	13.0	13.0
North Dakota	-	-	2.0	0.6
Total Rocky Mountain Region	95.0	61.8	61.0	41.5
Appalachian Basin	4.0	4.0	-	-
New York	1.0	1.0	-	-
Fort Worth Basin	1.0	1.0	-	-
Total	101.0	67.8	61.0	41.5

Drilling Programs

In August 2007, we completed the offering of our sponsored drilling partnership, Rockies Region 2007 Limited Partnership, and received subscriptions of approximately $90 million. We contributed $38.7 million for our general partner capital contribution. On December 28, 2007, the drilling partnership prepaid 2008 drilling costs of $54 million, in accordance with the partnership agreement, to secure intangible drilling cost tax deductions for the investing partners. This payment is included in advances for future drilling contracts on our accompanying condensed consolidated balance sheets. In early January 2008, we used this advance to pay down our credit facility. As of March 31, 2008, we have drilled for the Partnership a total of 100 wells, with completion and equipping operations to continue through the third quarter of 2008. The balance of the partnership's prepayment remaining at March 31, 2008, was $39.9 million. In January 2008, we announced that we do not plan to sponsor a new drilling partnership in 2008.

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of March 31, 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)	$ 203,000	$ -	$ -	$ -	$ 203,000
Interest on long-term debt(2)	240,797	24,360	48,720	48,720	118,997
Operating leases	4,921	2,194	1,993	682	52
Asset retirement obligations	21,213	50	100	100	20,963
Rig commitments (3)	22,925	10,605	12,320	-	-
Drilling Commiments(4)	3,217	-	717	-	2,500
Derivative agreements (5)	76,895	57,518	19,351	26	-

Other liabilities (6)	8,383	245	720	720	6,698
Total	$ 581,351	$ 94,972	$ 83,921	$ 50,248	$ 352,210

(1) Table does not include maximum annual repurchase obligation of $7 million as of March 31, 2008, see Note 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements.

(2) Amounts presented consist only of amounts due related to our 12% senior notes and does not include any amounts due under our credit facility as it was undrawn as of March 31, 2008. Interest on long-term debt, therefore, represents only amounts payable to holders of our 12% senior notes due 2018.

(3) Drilling rig commitments in the above table do not include future adjustments to daily rates as provided for in the agreements as such increases are not predictable and are only included in the above obligation table upon notification to us by the contractor of an increase in the rate.

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(4) Amounts represent our maximum obligation for potential liquidating damages if we do not comply with certain drilling and development agreements. See Note 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements. These amounts do not include advances for future drilling contracts totaling $40.9 million at March 31, 2008.

(5) Amount represents gross liability related to fair value of derivatives and related costs. Includes fair value of derivatives for natural gas marketing activities, Petroleum Development Corporation's share of oil and natural gas production and derivatives contracts we entered into on behalf of our affiliate partnerships as the managing general partner. We have a related net receivable from the partnerships of $18.4 million as of March 31, 2008.

(6) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

Commitments and Contingencies

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

Recent Accounting Standards

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

Critical Accounting Polices and Estimates

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

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 Disclosure 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 March 31, 2008, is $53.3 million with an average interest rate of 1.99%.

In February 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018, which we utilized to pay down our variable rate credit facility. The fixed-price debt transaction reduced our current sensitivity to interest rate fluctuations as we did not have any borrowings outstanding under our credit facility at March 31, 2008.

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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.

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 March 31, 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 futures contracts and option contracts for Appalachian and Michigan production, (ii) Panhandle-based contracts for NECO production, (iii) CIG-based contracts for other Colorado production and (iv) NYMEX-based swaps and collars for our Colorado oil production.

- For swap instruments, we receive a fixed price for the derivative contract and pay a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price is between the call and the put strike price, no payments are due from either party.

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 highly effective in achieving the risk management objectives for which they were intended.

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

	Three Months Ended March 31, 2008	Year Ended December 31, 2007
Average Index Closing Prices		
Oil (per Barrel)		

NYMEX	$ 93.69	$ 69.79
Natural Gas (per MMbtu)		
NYMEX	8.03	6.89
CIG	6.96	3.97
Average Sales Price		
Oil	81.14	60.65
Natural Gas	7.33	5.33

Based on a sensitivity analysis as of March 31, 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 $46.3 million and a 10% decrease in oil and natural gas prices would have resulted in a decrease in unrealized losses of $49.8 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 March 31, 2008.

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Credit Risk

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

Disclosure of Limitations

Because the information above included only those exposures that exist at March 31, 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 March 31, 2008, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the 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 the Chief Financial Officer concluded that as a result of the material weaknesses cited above, our disclosure controls and procedures were not effective as of March 31, 2008. Because of these material weaknesses, we performed additional procedures to ensure that our accompanying condensed consolidated financial statements as of and for the three months ended March 31, 2008, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

During the first quarter of 2008, we made the following changes in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect our internal controls over financial reporting:

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

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

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

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

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

(c) 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
January 1-31, 2008	225	$	59.98	225	1,464,864
February 1-29, 2008	52,712		68.12	52,712	1,412,152
March 1-31, 2008	11,173		67.33	11,173	1,400,979
	64,110		67.95	64,110	1,400,979

On October 16, 2006, our Board of Directors approved a share purchase program authorizing us to purchase up to 10% of our then outstanding common stock (1,477,109 shares) through April 2008. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that we deemed appropriate. Shares were purchased at fair market value based on the closing price on the date of purchase. For the three months ended March 31, 2008, 64,110 common shares were purchased at a cost of $4.4 million ($67.95 average price paid per share), including 13,756 shares from our executive officers at a cost of $0.9 million ($68.19 price paid per share). Shares purchased pursuant to the plan were primarily to satisfy the statutory minimum tax withholding requirement for restricted stock that vested and options exercised in 2008. All shares were subsequently retired. On February 8, 2008, pursuant to a separation agreement, we purchased 50,000 shares of our common stock from our former president pursuant to his separation agreement, at a cost of $3.4 million, or $67.92 per share. As the share purchase program expired on April 30, 2008, the remaining 1,400,979 shares authorized for purchase at March 31, 2008, have effectively expired.

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

Item 6. Exhibits

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

32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.

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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: May 12, 2008

/s/ Steven R. Williams
Steven R. Williams
Chief Executive Officer

Date: May 12, 2008

/s/ Richard W. McCullough
Richard W. McCullough
President and Chief Financial Officer