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, 2007

OR

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

Commission file number 000-07246

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

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

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,887,912 shares of the Company's Common Stock ($.01 par value) were outstanding as of June 15, 2007.

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

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

Large accelerated Filer ¨ Accelerated filer x Non-accelerated filer ¨

PETROLEUM DEVELOPMENT CORPORATION

INDEX

PART 1 – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

Index

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements *(unaudited)*

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

	March 31, 2007	December 31, 2006*
Assets		
Current assets:		
Cash and cash equivalents	$ 61,576	$ 194,326
Restricted cash	852	519
Accounts receivable, net	37,069	42,600
Accounts receivable - affiliates	9,668	9,235
Inventories	4,186	3,345
Fair value of derivatives	7,750	15,012
Other current assets	7,266	5,977
Total current assets	128,367	271,014
Properties and equipment, net	647,802	394,217
Restricted/designated cash	999	192,451
Other assets	2,354	26,605
Total assets	$ 779,522	$ 884,287
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 75,739	$ 67,675
Short term debt	-	20,000
Production tax liability	11,599	11,497
Other accrued expenses	5,584	9,685
Accounts payable - affiliates	4,637	7,595
Deferred gain on sale of leaseholds	25,600	8,000
Federal and state income taxes payable	10,476	28,698
Fair value of derivatives	3,192	2,545
Advances for future drilling contracts	19,040	54,772
Funds held for future distribution	42,474	31,367
Total current liabilities	198,341	241,834
Long-term debt	60,000	117,000
Deferred gain on sale of leaseholds	-	17,600
Other liabilities	23,217	19,400
Deferred income taxes	118,213	116,393
Asset retirement obligation	16,886	11,916
Total liabilities	416,657	524,143
Commitments and contingencies		

Shareholders' equity:		
Common stock, shares issued:14,890,626 in 2007 and 14,834,871 in 2006	149	148
Additional paid-in capital	698	64
Retained earnings	362,334	360,102
Treasury shares, at cost:		
4,957 in 2007 and 4,706 in 2006	(316)	(170)
Total shareholders' equity	362,865	360,144
Total liabilities and shareholders' equity	$ 779,522	$ 884,287

Derived from audited 2006 balance sheet.

See accompanying notes to condensed consolidated financial statements.

2

Index

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006 *Revised**
Revenues:		
Oil and gas sales	$ 34,016	$ 28,332
Gas sales from marketing activities	21,987	41,942
Oil and gas well drilling operations	4,030	5,278
Well operations and pipeline income	3,298	2,290
Oil and gas price risk management, net	(5,645)	4,925
Other	226	3
Total revenues	57,912	82,770
Costs and expenses:		
Oil and gas production and well operations cost	9,035	6,949
Cost of gas marketing activities	21,512	41,780
Cost of oil and gas well drilling operations	564	4,212
Exploration cost	2,678	1,208
General and administrative expense	7,424	3,719
Depreciation, depletion, and amortization	13,074	6,587
Total costs and expenses	54,287	64,455
Income from operations	3,625	18,315
Interest income	1,143	392
Interest expense	(831)	(352)
Income before income taxes	3,937	18,355
Income taxes	1,436	6,710
Net income	$ 2,501	$ 11,645
Earnings per common share:		
Basic	$ 0.17	$ 0.72
Diluted	$ 0.17	$ 0.72
Weighted average common shares outstanding:		
Basic	14,726	16,114
Diluted	14,854	16,199

*See Note 1.

See accompanying notes to condensed consolidated financial statements.

3

Index

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006 *Revised**
Cash flows from operating activities:		
Net income	$ 2,501	$ 11,645
Adjustments to net income to reconcile to cash (used in) provided by operating activities:		
Deferred income taxes	(3,379)	996
Depreciation, depletion and amortization	13,074	6,587
Accretion of asset retirement obligation	232	107
Exploratory dry hole costs	194	1,123
Expired and abandoned leases	53	17
Stock-based compensation	483	208
Unrealized loss (gain) on derivative transactions	6,636	(2,894)
Decrease in current assets	5,176	17,461
Decrease in other assets	131	2
Decrease in current liabilities	(60,935)	(33,433)
Increase in other liabilities	3,096	936
Net cash (used in) provided by operating activities	(32,738)	2,755
Cash flows from investing activities:		
Capital expenditures	(13,378)	(22,900)
Acquisitions	(144,218)	-
Acquisition of partnership interests	(57,270)	-
Decrease in restricted cash for property acquisition	191,452	-
Proceeds from sale of leases to partnerships	385	709
Net cash used in investing activities	(23,029)	(22,191)
Cash flows from financing activities:		
Proceeds from debt	70,000	49,000
Retirement of debt	(147,000)	(29,000)
Payment of debt issuance costs	-	(22)
Proceeds from exercise of stock options	152	31
Purchase of treasury stock	(135)	(10,153)
Net cash (used in) provided by financing activities	(76,983)	9,856
Net decrease in cash and cash equivalents	(132,750)	(9,580)
Cash and cash equivalents, beginning of period	194,326	90,110
Cash and cash equivalents, end of period	$ 61,576	$ 80,530

**See Note 1.*

See accompanying notes to condensed consolidated financial statements.

Index

Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
March 31, 2007
(Unaudited)

1. GENERAL

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

The accompanying 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 the opinion of management, the condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly the Company's financial position, results of operations and cash flows for the interim periods presented. The interim results of operations for the three months ended March 31, 2007, 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 the Company's audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on May 23, 2007 ("2006 Form 10-K").

Items Affecting Comparability

Reclassifications have been made to the income statement data presented for the three months ended March 31, 2006, to conform to the current year presentation and to correct the prior period presentation. These reclassifications had no impact on reported net earnings, earnings per share, shareholders' equity or total net cash flows. Oil and gas price risk management gains of $4.9 million for the three months ended March 31, 2006, have been reclassified from non-operating gains to a component of revenues. This reclassification and all other reclassifications are reflected in the revised amounts for March 31, 2006.

As described in Note 1 to the Consolidated Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 2006, during the fourth quarter of 2006, the Company adopted SEC Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. In accordance with SAB No. 108, the Company adjusted its opening financial position for 2006 by the cumulative effect of immaterial prior period misstatements. In connection with the adoption of SAB No. 108, the Company determined that certain similar errors were included in its results of operations for each of the first three quarters of 2006. The Company revised its quarterly results included in its selected quarterly data note included in its 2006 Form 10-K and revised the prior year quarterly financial statements included herein to reflect the correction of those immaterial misstatements.

The following table presents the income statement for the three months ended March 31, 2006, as previously presented in the Company's Form 10-Q for the related period, adjusted to reflect reclassifications to conform to current presentation and to correct previous presentation, and as revised to reflect the correction of prior period immaterial misstatements.

Index

	Three Months Ended March 31, 2006		
	Previously reported	Reclassified (1)	Revised (2)
	(in thousands, except per share data)		
Revenues:			
Oil and gas sales	$ 29,208	$ 29,208	$ 28,332
Gas sales from marketing activities	41,942	41,942	41,942
Oil and gas well drilling operations	5,278	5,278	5,278
Well operations and pipeline income	2,290	2,290	2,290
Oil and gas price risk management, net	-	4,435	4,925
Other	391	3	3
Total revenues	79,109	83,156	82,770
Costs and expenses			
Oil and gas production and well operations cost	7,105	7,261	6,949
Cost of gas marketing activities	41,775	41,775	41,780
Cost of oil and gas well drilling operations	4,216	4,081	4,212
Exploration costs	1,078	1,163	1,208
General and administrative expenses	3,980	3,981	3,719
Depreciation, depletion and amortization	6,616	6,616	6,587
Total costs and expenses	64,770	64,877	64,455
Income from operations	14,339	18,279	18,315
Interest income	-	388	392
Interest expense	(180)	(73)	(352)
Oil and gas price risk management, net	4,435	-	-
Income before income taxes	18,594	18,594	18,355
Income taxes	6,796	6,796	6,710
Net Income	$ 11,798	$ 11,798	$ 11,645
Basic earnings per common share	$ 0.73	$ 0.73	$ 0.72
Diluted earnings per share	$ 0.73	$ 0.73	$ 0.72

(1) As previously reported in the corresponding Form 10-Q, reclassified to conform to current year presentation.
(2) Reflects the impact of certain immaterial errors on the quarterly results previously reported in 2006.

The reclassifications and revisions discussed above have no impact on the balance sheets presented herein, nor do they result in changes to the net increase (decrease) in cash and cash equivalents previously presented in the Form 10-Q for the three months ended March 31, 2006. However, certain line items within cash flows from operating activities and one line item within cash flow from investing activities for the three months ended March 31, 2006, have been adjusted herein to reflect the impact of the income statement revisions. Revised line items are as follows:

Index

	Three Months Ended March 31, 2006	
	Previously Presented	Revised (1)
Certain statement of cash flow line items:	*(in thousands)*	
Net income	$ 11,798	$ 11,645
Deferred income taxes	1,022	996
Depreciation, depletion & amortization	6,616	6,587
Exploratory dry hole cost	1,078	1,123
Unrealized gain on derivative transactions	(2,411)	(2,894)
Decrease in current assets	16,883	17,461
Decrease in other current liabilities	(33,312)	(33,433)
Increase in other liabilities	869	936
Net cash provided by operating activities	2,878	2,755
Capital expenditures	(23,025)	(22,900)
Net cash used in investing activities	(22,314)	(22,191)

(1) Reflects the impact of certain immaterial errors on the quarterly results previously reported in 2006.

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

In June 2006, the Financial Accounting Standards Board ("FASB") issued Emerging Issues Task Force ("EITF") No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. EITF 06-3 addresses the income statement presentation of any tax collected from customers and remitted to a government authority and concludes that the presentation of taxes on either a gross basis or a net basis is an accounting policy decision that should be disclosed pursuant to Accounting Principles Board ("APB") No. 22, *Disclosures of Accounting Policies*. For taxes that are reported on a gross basis (included in revenues and costs), EITF 06-3 requires disclosure of the amounts of those taxes in interim and annual financial statements, if those amounts are significant. EITF 06-3 became effective for interim and annual reporting periods beginning after December 15, 2006. The adoption of the standard, effective January 1, 2007, did not have a significant impact on the consolidated financial statements. The Company's existing accounting policy is to present taxes within the scope of EITF 06-3 on a net basis.

In July 2006, the FASB issued FASB Interpretation (“FIN”) No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109*, which prescribes a comprehensive model for accounting for uncertainty in tax positions. FIN No. 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service ("IRS"), based on the technical merits of the position. The provisions of FIN No. 48 are effective for the Company on January 1, 2007. The cumulative effect of applying the provisions of FIN No. 48 has been accounted for as an adjustment to retained earnings in the first quarter of 2007. The adoption of FIN No. 48 resulted in a $0.3 million cumulative effect adjustment. See Note 5 for further discussion.

Recently Issued Accounting Standards

In September 2006, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 157, *Accounting for Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value within generally accepted accounting principles and expands required disclosure about fair value measurements. SFAS No. 157 does not expand the use of fair value in any new circumstances. The provisions of SFAS No. 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect the new standard to have any material impact on its consolidated financial statements when adopted in 2008.

Index

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. The Company is evaluating the impact of adopting SFAS No. 159 in its consolidated financial statements when it is adopted in 2008.

3. ACQUISITIONS

Acquisition of Internal Revenue Code Section 1031 – Like-Kind Exchange Properties

During the first quarter of 2007, the Company completed its acquisitions of suitable like-kind properties in accordance with the like-kind exchange ("LKE") agreement it entered into in connection with its sale of undeveloped leaseholds located in Grand Valley Field, Garfield County, Colorado in July 2006. The Company acquired for cash qualifying oil and gas properties totaling $189.5 million, including costs of acquisition, as described below.

EXCO Properties. On January 5, 2007, the Company completed its purchase of producing properties and remaining undeveloped drilling locations and acreage in the Wattenberg Field area of the DJ Basin, Colorado from EXCO Resources Inc., an unaffiliated party. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 oil and gas wells (approximating 25.5 Bcfe proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. The Company will operate the assets and holds a majority working interest in the properties.

Company-Sponsored Partnerships. On January 10, 2007, the Company completed the purchase of the remaining working interests in 44 Company-sponsored partnerships. The transaction resulted in an increase in the Company's ownership in 718 gross wells (423 net wells) that are currently operated by the Company. The wells are located primarily in the Appalachian Basin and Michigan.

The following table presents the preliminary purchase price for each of the acquisitions described above:

	EXCO	Partnerships
	(in thousands)	
Cash consideration paid	$ 128,672	$ 57,776
Plus: direct costs of acquisition	1,625	1,664
Less: acquisition cost adjustments	(119)	(2,170)
Total preliminary acquisition cost	$ 130,178	$ 57,270

Index

The following table presents, as of the respective date of acquisition, the preliminary allocations of the purchase prices based on preliminary estimates of fair value:

	EXCO	Partnerships
	(in thousands)	
Current assets acquired	$ 91	$ -
Proved oil and gas properties	117,392	47,354
Unproved oil and gas properties	14,956	13,410
Asset retirement obligation	(747)	(3,494)
Other liabilities assumed	(1,514)	-
Preliminary acquisition cost	$ 130,178	$ 57,270

The assessment of fair value of proved oil and gas properties acquired was based primarily on projections of expected discounted future cash flows of acquired oil and gas reserves. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable reserves were reduced by additional risk-weighting factors in that valuation. The purchase price allocations are preliminary, subject to fair value appraisals and evaluations of the assets acquired. The amounts are subject to change as additional information becomes available and is assessed by the Company.

Other. In January 2007, the Company acquired from unaffiliated parties other like-kind undeveloped leaseholds in Erath County, Texas for $2.1 million, including costs of acquisition. Acreage in this area is prospective for development of gas and oil reserves in the Barnett Shale.

Other Acquisitions

Unioil. On December 6, 2006, the Company completed a cash tender offer and purchased approximately 95.5% or 9,112,750 shares of the outstanding common stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The acquisition of more than 90% of the outstanding shares of common stock allowed the Company to effect a short-form merger of Unioil and a wholly owned subsidiary of the Company, resulting in the acquisition of the remaining 428,719 shares of Unioil. Each share of Unioil common stock not tendered through the offer was converted into the right to receive $1.91 in cash, the same consideration paid for shares in the tender offer. The Company paid $18.6 million, including $0.4 million of direct acquisition costs, for 100% of Unioil’s outstanding common stock.

The assessment of the fair values of oil and gas properties acquired was based primarily on projections of expected future net cash flows, discounted to present value. The preliminary acquisition cost allocation included $6.8 million in goodwill, which was re-allocated to properties and equipment in the first quarter of 2007 as part of the Company's ongoing process of finalizing the allocation of the preliminary purchase price. As a result of this reclass, the deferred tax liabilities increased and thus increased property and equipment. This increase was approximately $4.2 million. The purchase price allocation is preliminarily subject to finalizing fair value appraisals and completing evaluations of proved and unproved oil and gas properties. These amounts are subject to change as additional information becomes available and is assessed by the Company.

The results of Unioil's operations have been included in the consolidated financial statements from the date of acquisition, December 6, 2006. The pro forma effect of the inclusion of the results of Unioil's operations in the Company's consolidated statement of income for the three months ended March 31, 2006, was not material.

Other. On February 22, 2007, the Company acquired, from an unaffiliated party, 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $12 million, which was allocated to oil and gas properties.

Index

Pro Forma Financial Information

The results of operations for all of the above acquisitions have been included in the condensed consolidated financial statements from the date of acquisition. The pro forma effect of the inclusion of the results of operations for all of the above acquisitions, individually and in the aggregate, in the Company's condensed consolidated statement of income for the three months ended March 31, 2007, was not material.

The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the three months ended March 31, 2006, assuming the acquisitions of the EXCO properties and Company-sponsored partnerships had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase price to the acquired net assets. The pro forma effect of the inclusion of the results of operations for all of the other acquisitions described above, individually and in the aggregate, was not material.

	Three Months Ended March 31, 2006 *(in thousands, except per share data)*
Total revenues	$ 90,707
Net income	14,032
Earnings per common share:	
Basic	$ 0.87
Diluted	$ 0.87

The pro forma results of operations are not necessarily indicative of what the Company's results of operations would have been had the EXCO properties and Company-sponsored partnerships been acquired at the beginning of the period indicated, nor does it purport to represent results of operations for any future periods.

4. DESIGNATED CASH

In July 2006, the Company established a trust in the amount of $300 million with a qualified intermediary in conjunction with its sale of undeveloped leaseholds and corresponding LKE agreement. As of December 31, 2006, $300 million remained in the trust, with $109 million reflected in cash and cash equivalents as a current asset in the condensed consolidated balance sheet and the remaining $191.5 million reflected as designated cash – property acquisitions, a non-current asset. The $191.5 million represents the amounts paid in January 2007 for the acquisition of oil and gas properties qualifying for LKE treatment and is included in oil and gas properties at March 31, 2007.

5. INCOME TAXES

Effective January 1, 2007, the Company adopted FIN No. 48, which clarifies the accounting for uncertainty in income taxes recognized in an entity’s financial statements in accordance with FASB Statement 109, *Accounting for Income Taxes*, by prescribing the minimum recognition threshold and measurement attribute a tax position taken or expected to be taken on a tax return is required to meet before being recognized in the financial statements. The Company recorded a $0.3 million reduction in retained earnings at January 1, 2007, to recognize the cumulative effect of the adoption of FIN No. 48. This amount represents the total amount of interest on unrecognized tax benefits as of the date of adoption. As of January 1, 2007, unrecognized tax benefits amounted to $1 million and are included in income taxes payable in the condensed consolidated balance sheet. No amount of this balance relates to a position which, if recognized, would impact the Company's effective tax rate. The Company does not expect that any unrecognized tax benefits will significantly increase or decrease in the next 12 months.

Index

The Company will, as a matter of accounting policy, recognize interest and penalties related to unrecognized tax benefits, if any, in income tax expense in the condensed consolidated statements of income. During the three months ended March 31, 2007, there was no material change to the amount of interest on unrecognized tax benefits. Accruals for interest totaled $0.3 million at March 31, 2007, which are included in income taxes payable in the condensed consolidated balance sheet. There are no accruals for penalties at January 1, 2007 or during the quarter ended March 31, 2007.

The Company's federal income tax returns are closed through the tax year 2002 and there are no outstanding tax controversies with any taxing authorities regarding these prior tax years. The IRS is currently examining the Company's 2003 and 2004 tax years and is substantially done with their examination although a final report of adjustments has not been received.

State and other income tax returns are generally subject to examination for a period of three to five years after the filing of the respective returns. The state impact of any amended federal returns, whether or not pursuant to IRS examination changes or pursuant to Company voluntary changes, remains subject to examination by various states for a period of up to one year after formal notification of such amendments to the states. The Company currently has no state income tax returns in the process of examination or administrative appeal.

The Company filed its 2004 state income tax returns on June 5, 2007, so the statute of limitations for examination and adjustment did not begin until the late filing date. The Company is currently delinquent in its 2005 federal and state income tax filings and plans to file these returns as soon as possible. Accordingly, the normal federal and state statute of limitations for this tax year will not begin until the return filing dates.

6. EARNINGS PER SHARE

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

	Three Months Ended March 31,	
	2007	2006
	(in thousands, except per share data)	
Weighted average common shares outstanding	14,726	16,114
Dilutive effect of share-based compensation:		
Unamortized portion of restricted stock	63	18
Stock options	60	67
Non employee director deferred compensation	5	-
Weighted average common and common equivalent shares outstanding	14,854	16,199
Net income	$ 2,501	$ 11,645
Basic earnings per common share	$ 0.17	$ 0.72
Diluted earnings per common share	$ 0.17	$ 0.72

Options with an exercise price exceeding the average price of the underlying securities are not considered to be dilutive, or anti-dilutive, and are not included in the calculation of the denominator for diluted earnings per share. There were no common share equivalents attributable to anti-dilutive options for the three months ended March 31, 2007 or 2006.

Index

7. STOCK-BASED COMPENSATION

The Company maintains a long-term equity compensation plan for officers and certain key employees of the Company. In accordance with the plan, awards may be issued in the form of stock options, stock appreciation rights, restricted stock or performance shares. Total stock-based compensation cost recognized in the consolidated statements of income, and the related tax benefit was $0.5 million and $0.2 million for the three months ended March 31, 2007, and $0.2 million and $0.1 million for the three months ended March 31, 2006.

Stock Option Awards. The Company 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. The Company did not grant any stock option awards for the three months ended March 31, 2007. The weighted average fair value per share of the options granted during the three months ended March 31, 2006, as computed using the Black-Scholes pricing model was $18.92. The weighted average assumptions used to estimate these fair values were as follows:

	Three Months Ended March 31, 2006
Expected Volatility	39.5%
Expected term (in years)	5.9
Risk-free interest rate	4.3%

Expected volatilities are based on the Company's historical volatility. The expected life of an award is estimated using historical exercise behavior data. The risk-free interest rate is based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the expected life of the award. The Company does not expect to pay dividends, nor does it expect to declare dividends in the foreseeable future.

The following table provides a summary of the Company's stock option award activity for the three months ended March 31, 2007:

	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, 2006	89,567	$ 21.36	5.6	$ 2.0
Exercised	(30,000)	5.06	-	1.3
Outstanding at March 31, 2007	59,567	29.56	6.4	1.4
Vested and expected to vest at March 31, 2007	55,808	28.53	6.3	1.4
Exercisable at March 31, 2007	32,529	18.93	4.6	1.1

Total unrecognized stock-based compensation cost related to stock options was $0.4 million as of March 31, 2007. This cost is expected to be recognized over a weighted average period of 2.5 years.

Index

Restricted and Performance Share Awards. During the three months ended March 31, 2007, the Company awarded 29,041 restricted shares with a weighted average grant date fair value of $50.90 per share and 31,972 performance vesting shares of restricted stock with a weighted average grant date fair value of $36.07 per share. The fair value of the restricted awards is amortized over the vesting period, ratably over four years from the date of grant. The restricted shares, which are subject to performance vesting, vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. The weighted average grant date fair value of each performance share was computed using the Monte Carlo pricing model and the following weighted average assumptions:

Expected term of award	3 years
Risk-free interest rate	4.7%
Volatility	44.0%

The following table provides a summary of the Company's restricted and performance share awards activity for the three months ended March 31, 2007:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2006	131,730	$ 39.87
Granted	61,013	43.13
Vested	(6,328)	44.95
Forfeited	(620)	41.04
Non-vested at March 31, 2007	185,795	40.76

The total compensation cost related to non-vested and expected to vest awards not yet recognized as of March 31, 2007, is $5.2 million. The cost is expected to be recognized over a weighted-average period of 3 years.

8. PROPERTIES AND EQUIPMENT

	March 31, 2007	December 31, 2006
	(in thousands)	
Properties and Equipment:		
Oil and gas properties (successful efforts method of accounting)	$ 762,809	$ 500,506
Pipelines	13,461	12,673
Transportation and other equipment	9,062	7,870
Land and buildings	10,904	11,620
Construction in progress	7,893	4,801
	804,129	537,470
Less accumulated depreciation, depletion and amortization	156,327	143,253
	$ 647,802	$ 394,217

Index

Suspended Well Costs.

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in oil and gas properties in the accompanying balance sheets in accordance with FASB Staff Position No. 19-1, *Accounting for Suspended Well Costs*.

	Amount *(in thousands)*	Number of Wells
Beginning balance at December 31, 2006	$ 765	1
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,166	3
Capitalized exploratory well costs charged to expense	(765)	(1)
Ending balance at March 31, 2007	$ 1,166	3

As of March 31, 2007, none of the three wells awaiting the determination of proved reserves has been capitalized for a period greater than one year.

9. ASSET RETIREMENT OBLIGATION

Changes in carrying amounts of the asset retirement obligations associated with the Company's working interest in oil and gas properties are as follows:

	Amount *(in thousands)*
Beginning balance at December 31, 2006	$ 11,966
Obligations assumed with development activities and acquisitions	4,738
Accretion expense	232
Revisions to estimated cash flows	-
Ending balance at March 31, 2007	$ 16,936

10. LONG-TERM DEBT

The Company has a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. Effective May 25, 2007, the Company's current borrowing base, based upon current oil and gas reserves, was increased from $100 million to $135 million, which is fully activated. The Company is required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at the discretion of the Company. 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 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. No principal payments are required until the credit agreement expires on November 4, 2010.

On December 19, 2006, the Company executed pursuant to its credit facility an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.80% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January 2007.

Index

As of March 31, 2007, the outstanding balance under the facility, including the overline note, was $60 million compared to $117 million, excluding the overline note discussed above, as of December 31, 2006. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. At March 31, 2007, an outstanding balance of $60 million was subject to a prime interest rate of 8.25%. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves and the maintenance of certain working capital and tangible net worth ratios. At March 31, 2007, the Company was not in compliance with its current ratio covenant. As of the filing of this quarterly report, the Company was not in compliance with the requirement to timely file its March 31, 2007, Form 10-Q. The Company has received a waiver from the banks for the current ratio covenant violation at March 31, 2007, and was granted a waiver related to the delay in the delivery of its March 31, 2007, interim condensed consolidated financial statement until June 30, 2007.

11. SUPPLEMENTAL CASH FLOW DISCLOSURE

	Three Months Ended March 31,	
	2007	2006
	(in thousands)	
Cash paid for:		
Interest	$ 2,205	$ 200
Income taxes	24,781	8,250
Non-cash investing activities:		
Change in deferred tax liability resulting from reallocation of acquisition purchase price	4,188	-
Changes in accounts payable related to purchases of property and equipment	17,563	-

12. COMMITMENTS AND CONTINGENCIES

The Company would be exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's derivative instruments or the counterparties to the Company's gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2006 or the first quarter of 2007.

In connection with the Company’s sale of undeveloped leaseholds in July 2006, the Company, pursuant to the purchase and sale agreement, is obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per un-drilled well for a total contingent obligation of $25.6 million, which is reflected as a deferred gain on sale of leaseholds in the accompanying condensed consolidated balance sheets. On May 31, 2007, the Company entered into a letter agreement amending the original purchase and sale agreement. The letter agreement relieves the Company of its obligation, in its entirety, to either drill 16 wells or pay liquidated damages. See Note 16.

Pursuant to the above letter agreement, the Company is obligated to drill six wells on specifically identified acreage. These wells will be drilled on the unaffiliated party's leasehold for its benefit and at its cost. In addition, the unaffiliated party will return 160 acres of leasehold property acquired from the Company pursuant to the purchase and sale agreement.

The Company is party to an exploration agreement with an unaffiliated party. The agreement requires the Company to drill a minimum of 25 wells through June 30, 2007. For each well the Company fails to drill prior to June 30, 2007, the Company will be required to pay liquidated damages equal to $125,000 per un-drilled well, for a maximum contingency of $3.1 million. During June 2007, the Company determined it would not be able to fulfill its obligation after drilling three wells. The Company was not able to renegotiate the agreement and will pay the liquidated damages. The Company will record the liquidated damages of $2.75 million and an impairment of the $1.1 million carrying value of the cost of the acreage to exploration expense in the second quarter of 2007.

Substantially all of the Company's drilling programs contain a repurchase provision where investing partners may request that the Company purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is 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 the Company's financial ability to do so. The maximum annual potential repurchase obligation as of March 31, 2007, was approximately $6.5 million. The Company has adequate liquidity to meet this potential obligation. During 2006 and the first quarter of 2007, the Company paid $0.8 million and $0.3 million, respectively, under this provision for the repurchase of partnership units.

Index

As managing general partner of 32 partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes the casualty insurance coverage carried by the Company and its subcontractors is adequate to meet this potential liability.

In order to secure the services for two drilling rigs, the Company made commitments to the drilling contractors, which call for a minimum commitment of $9,000 daily for a specified amount of time if the Company ceases to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $34,400 daily for a specified amount of time for daily use of the drilling rigs. As of March 31, 2007, commitments for these two separate contracts expire in July 2009 and May 2010. As of March 31, 2007, the Company has an outstanding minimum commitment for $8.6 million and an outstanding maximum commitment for $33 million.

13. LEGAL PROCEEDINGS

From time to time the Company is a party to various legal proceedings in the ordinary course of business. While it is not possible to determine with any degree of certainty the ultimate outcome of the following legal proceeding, the Company believes that it has meritorious defenses with respect to the claims asserted against it and intends to vigorously defend its position. An adverse outcome in this case or any similar case could have a material adverse effect, individually and collectively, on the Company’s financial position, liquidity and results of operations.

Royalty Payments. 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 the Company underpaid royalties on gas produced from wells operated by the Company 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 made by the Company to the plaintiff pursuant to leases. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, the Company is unable to predict the ultimate outcome of this suit at this time.

Litigation similar to the Droegemueller Action has recently been commenced against several other companies in jurisdictions where the Company conducts business. While the Company's 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.

Other. The Company is involved in various other legal proceedings that it considers normal to its business. While it is not feasible to predict the ultimate outcome of such other proceedings, the Company believes that the ultimate outcome of such other proceedings will not have a material adverse effect on its financial position, liquidity or results of operations.

14. BUSINESS SEGMENTS

The Company's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations and pipeline income. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas ("RNG"), engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 3,100 wells from which it sells its oil and gas production from its working interests in the wells. The Company charges 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, 2007 and 2006, is presented below.

16

Index

	Three Months Ended March 31,			
	2007		2006	
	(in thousands)			
Revenues:				
Oil and gas sales (1)	$	28,371	$	33,257
Natural gas marketing		21,987		41,942
Drilling and development		4,030		5,278
Well operations and pipeline income		3,298		2,290
Unallocated amounts		226		3
Total	$	57,912	$	82,770
Segment income (loss) before income taxes:				
Oil and gas sales (2)	$	5,839	$	20,477
Natural gas marketing		679		324
Drilling and development		3,467		1,067
Well operations and pipeline income		1,234		419
Unallocated amounts (3)		(7,282)		(3,932)
Total	$	3,937	$	18,355

	March 31, 2007		December 31, 2006	
	(in thousands)			
Segment assets:				
Drilling and development (4)	$	49,429	$	87,746
Natural gas marketing		35,761		39,899
Oil & gas sales		632,061		394,952
Well operations and pipeline income		30,543		28,895
Unallocated amounts (5)		31,728		332,795
Total	$	779,522	$	884,287

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(1) Includes oil and gas price risk management, net.

(2) Includes $2.7 million and $1.2 million in exploration costs and $12.4 million and $6.1 million of DD&A for the three months ended March 31, 2007 and 2006, respectively.

(3) Includes general and administrative expense, interest income, interest expense, and DD&A expense of $0.2 million and $0.1 million for the three months ended March 31, 2007 and 2006, respectively.

(4) The December 31, 2006, amount includes cash of $50.7 million for partnership drilling activities, which was substantially utilized by March 31, 2007.

(5) *Includes primarily unallocated cash. The December 31, 2006, amount includes designated cash of $191.5 million, which was utilized in LKE property transactions during the first quarter of 2007 and included in the oil and gas sales segment as of March 31, 2007.*

15. DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes commodity based derivative instruments to manage a portion of its exposure to price risk from its oil and natural gas sales and marketing activities. Company policy prohibits the use of oil and natural gas future and option contracts for speculative purposes. These instruments consist of New York Mercantile Exchange ("NYMEX") traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for Northeast Colorado ("NECO") production and Colorado Interstate Gas Index ("CIG") based contracts for other Colorado production. The Company purchases puts and participating collars for its own and affiliate partnerships production to protect against possible price instability in future periods while retaining much of the benefits of price increases. In the case of RNG, these derivative instruments have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the derivative relates and the cost of gas supplies purchased for marketing activities. As a result, while these derivatives are structured to reduce the Company's exposure to changes in price associated with the derivative commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the derivative commodity. RNG also enters into fixed-price physical purchase and sale agreements that are derivative contracts.

Index

The following tables summarize the open derivative option and purchase and sales contracts for RNG and the Company as of March 31, 2007.

Riley Natural Gas
Open Derivative Positions
(Dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of March 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	167,100	$ 7.86	$ 1,314	$ (47)
Natural Gas	Cash Settled Futures/Swaps Sales	2,710,200	8.30	22,502	(208)
Natural Gas	Cash Settled Option Purchases	180,000	5.50	990	8
Natural Gas	Cash Settled Option Sales	90,000	10.10	909	(34)
Natural Gas	Physical Purchases	2,713,200	8.37	22,703	696
Natural Gas	Physical Sales	34,096	9.79	334	49
Positions maturing in 12 months following March 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	167,100	$ 7.86	$ 1,314	$ (47)
Natural Gas	Cash Settled Futures/Swaps Sales	2,229,200	8.27	18,430	(119)
Natural Gas	Cash Settled Option Purchases	180,000	5.50	990	8
Natural Gas	Cash Settled Option Sales	90,000	10.10	909	(34)
Natural Gas	Physical Purchases	2,232,200	8.35	18,627	799
Natural Gas	Physical Sales	34,096	9.79	334	49

The maximum term for the derivative contracts listed above is 22 months.

Petroleum Development Corporation
Open Derivative Positions
(Dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of March 31, 2007					
Natural Gas	Cash Settled Option Sales	7,040,000	$ 10.64	$ 74,902	$ (3,538)
Natural Gas	Cash Settled Option Purchases	22,460,000	5.36	120,388	7,484
Oil	Cash Settled Option Purchases	210,000	50.00	10,500	28

Positions maturing in 12 months following March 31, 2007								
Natural Gas	Cash Settled Option Sales	5,220,000	$	10.70	$	55,845	$	(2,683)
Natural Gas	Cash Settled Option Purchases	20,640,000		5.29		109,188		6,558
Oil	Cash Settled Option Purchases	210,000		50.00		10,500		28

The maximum term for the derivative contracts listed above is 19 months.

In addition to including the gross assets and liabilities related to the Company's share of oil and gas production, the above tables and the accompanying condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The accompanying condensed consolidated balance sheets include the fair value of derivatives and a corresponding net receivable from the partnerships of $2.1 million as of March 31, 2007, and a net payable to the partnerships of $7.5 million as of December 31, 2006. In addition to the short-term fair value of derivatives shown in the accompanying condensed consolidated balance sheet there are long-term assets and long-term liabilities which total to a net long-term liability of approximately $0.1 million as of March 31, 2007, and a net long-term asset of approximately $0.9 million as of December 31, 2006, respectively, related to the fair value of derivatives included in the accompanying condensed consolidated balance sheets.

Index

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of March 31, 2007, and December 31, 2006, restricted cash in the amount of $0.9 million and $0.5 million was on deposit.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults during the three months ended March 31, 2007 and 2006.

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

	March 31, 2007	December 31, 2006
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	$ 7,750	$ 15,012
Other assets - long-term asset	926	1,146
	8,676	16,158
Fair value of derivatives - current liability	3,192	2,545
Other liabilities - long-term liability	1,046	-
	4,238	2,545
Net fair value of commodity based derviatives	$ 4,438	$ 13,613

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,			
	2007		2006	
Statement of Income Line Item	Realized gains/(losses)	Unrealized gains/(losses)	Realized gains/(losses)	Unrealized gains/(losses)
	(in millions)			
Oil and gas price risk management gain (loss), net	$ 0.6	$ (6.2)	$ 1.4	$ 3.5 (1)
Gas sales from marketing activities	1.1	(3.3)	0.1	8.7
Cost of gas marketing activities	(0.2)	2.9	(0.6)	(9.3)

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(1) *Revised, see Note 1.*

16. SUBSEQUENT EVENTS

In July 2006, the Company and an unaffiliated party entered into a purchase and sale agreement regarding the sale of the Company's undeveloped leasehold located in the Grand Valley Field, Garfield County, Colorado ("PSA"), as filed with the SEC as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 2006. On May 31, 2007, the Company and the unaffiliated party entered into a letter agreement amending the PSA. The letter agreement relieves the Company of its obligation, in its entirety, to either drill 16 wells on specifically identified acreage over the next three years, at the Company's cost and the Company's benefit, or pay liquidated damages of $1.6 million per un-drilled well. As a result, the Company will recognize the related, remaining deferred gain on sale of leaseholds of $25.6 million as a gain on the sale of leaseholds in the second quarter of 2007.

Pursuant to the letter agreement, the Company is obligated to drill six wells on specifically identified acreage. These wells will be drilled on unaffiliated party's leasehold for its benefit and at its cost. In addition, the unaffiliated party will return 160 acres of leasehold property acquired from the Company pursuant to the PSA.

Index

The Company is party to an exploration agreement with an unaffiliated party. The agreement requires the Company to drill a minimum of 25 wells through June 30, 2007. For each well the Company fails to drill prior to June 30, 2007, the Company will be required to pay liquidated damages equal to $125,000 per un-drilled well, for a maximum contingency of $3.1 million. During June 2007, the Company determined it would not be able to fulfill its obligation after drilling three wells. The Company was not able to renegotiate the agreement and will pay the liquidated damages. The Company will record the liquidated damages of $2.75 million and an impairment of the $1.1 million carrying value of the cost of the acreage to exploration expense in the second quarter of 2007.

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

Management Overview

Net income for the three months ended March 31, 2007, was $2.5 million compared to $11.6 million for the same prior year period. The principal reason for the decline in profitability is the wide swing in oil and gas price risk management, which decreased a total of $10.5 million from a gain of $4.9 million for the three months ended March 31, 2006, to a loss of $5.6 million for the three months ended March 31, 2007. In both periods the majority of the gains or losses were unrealized. See Oil and Gas Price Risk Management discussion below for a detailed discussion of realized and unrealized gains and losses on oil and gas derivative activity.

The Company's total oil and natural gas production increased by 1.6 Bcfe or approximately 43% during the quarter ended March 31, 2007, as compared to the quarter ended March 31, 2006, from 3.7 Bcfe to 5.3 Bcfe. During this same time period, the average sales price per Mcfe decreased by approximately 17.1% from $7.70 per Mcfe during the quarter ended March 31, 2006, to $6.38 per Mcfe during the quarter ended March 31, 2007. See the table below under Oil and Gas Production. Notwithstanding the substantial increase in the Company's production on a quarter-by-quarter basis, the decrease in the average sales prices of the commodities had a significant negative impact upon the Company's operating results.

Results of Operations

Three Months Ended March 31, 2007, Compared to Three Months Ended March 31, 2006

Revenues

Total revenues for the three months ended March 31, 2007, were $57.9 million compared to $82.8 million for the same prior year period, a decrease of $24.9 million or 30.1%. The decrease was primarily the result of decreases in gas sales from marketing activities and oil and gas price risk management as discussed above, offset in part by an increase in the oil and gas sales.

Costs and Expenses

Costs and expenses for the three months ended March 31, 2007, were $54.3 million compared to $64.5 million for the same prior year period, a decrease of $10.2 million or 15.8%. The decrease was primarily the result of decreases in cost of oil and gas well drilling operations and cost of gas marketing activities offset in part by increases in exploration costs, general and administrative expenses and depreciation, depletion and amortization.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended March 31, 2007, were $34.0 million compared to $28.3 million for the same prior year period, an increase of $5.7 million or 20.1%. The increase was primarily due to increased volumes of natural gas and oil partially offset by lower average sales prices of natural gas and oil.

Index

The increased volume of natural gas and oil contributed $10.6 million to oil and gas sales, while the decline in prices reduced oil and gas sales by $4.9 million for a net increase of $5.7 million for the first quarter of 2007 compared to the same prior year period. The volume of natural gas sold for the three months ended March 31, 2007, was 4.1 Bcf at an average sales price of $6.05 per Mcf compared to 2.9 Bcf at an average sales price of $7.17 per Mcf for the three months ended March 31, 2006. Oil sales were 199,500 barrels at an average sales price of $45.06 per barrel for the three months ended March 31, 2007, compared to 127,700 barrels at an average sales price of $58.28 per barrel for the three months ended March 31, 2006. The majority of the increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily the first quarter acquisitions and the significant increased number of wells drilled for the Company's own account over the past year.

Oil and Gas Production

The Company's 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, 2007			Three Months Ended March 31, 2006		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	1,374	609,397	617,641	489	408,425	411,359
Michigan Basin	815	420,887	425,777	1,089	356,292	362,826
Rocky Mountains	197,350	3,105,669	4,289,769	126,135	2,147,963	2,904,773
Total	199,539	4,135,953	5,333,187	127,713	2,912,680	3,678,958
Average Sales Price	$ 45.06	$ 6.05	$ 6.38	$ 58.28	$ 7.17	$ 7.70

**One barrel of oil is equal to the energy equivalent of six Mcf of natural gas.*

Financial results depend upon many factors, particularly the price of natural gas and the Company’s ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company’s financial results. Natural gas and oil 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 can entail a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction which will help to maintain a balance between supply and demand. However, there may be times in which there may be oversupply situations for short or longer terms, which may affect the amount of gas or oil that the Company can sell, and the price at which it sells gas or oil. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, so their timing is not within its control. See Natural Gas Pricing and Pipeline Capacity in Liquidity and Capital Resources.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas ("RNG"), the Company's gas marketing subsidiary, for the three months ended March 31, 2007, were $22 million compared to $41.9 million for the same prior year period, a decrease of $19.9 million or 47.5%. The decrease was due to significantly lower average price of natural gas sold and unrealized losses on derivative transactions, which were $3.3 million for the three months ended March 31, 2007, partially offset by higher volumes compared to unrealized gains of $8.7 million for the three months ended March 31, 2006. The costs of gas marketing activities for the three months ended March 31, 2007, were $21.5 million compared to $41.8 million for the three months ended March 31, 2006, a decrease of $20.3 million or 48.6%. The decrease was due to significantly lower prices and unrealized gains on derivative transactions, which were $2.9 million for the three months ended March 31, 2007, partially offset by higher volumes of natural gas purchased compared to unrealized losses on derivative transactions of $9.3 million for the three months ended March 31, 2006. Income before income taxes for the Company's natural gas marketing subsidiary increased from a profit of $0.3 million for the three months ended March 31, 2006, to a $0.7 million profit for the three months ended March 31, 2007.

Index

Drilling Operations

In the first quarter of 2006, the Company, in addition to its remaining footage-based drilling arrangements, began recognizing revenues for its cost-plus drilling arrangements with its partnerships. The cost-plus drilling arrangements began with the private program partnership funded by the Company in late December 2005 and continued in the 2006 partnership funded on September 1, 2006, which started drilling operations in the third quarter of 2006 and continued through the first quarter of 2007. The Company's services provided under the cost-plus drilling arrangements are reported net of recovered costs and reflected as revenue in oil and gas well drilling operations. Revenue from oil and gas well drilling operations for the three months ended March 31, 2007, was $4 million compared to $5.3 million for the same prior year period, a decrease of $1.3 million. The decrease was due to the Company's change in type of drilling contract. The three months ended March 31, 2007, included $2 million of revenue from footage-based contracts.

Cost of oil and gas well drilling operations decreased $3.6 million to $0.6 million for the three months ended March 31, 2007, from $4.2 million in the same prior year period. The decrease was due to the Company's revenue reporting for its cost-plus drilling arrangements as described above.

The completion of the remaining footage-based arrangements, which incurred losses during 2006, improved the profitability of the drilling operations from a gross profit of $1.1 million for the three months ended March 31, 2006, to $3.4 million for the three months ended March 31, 2007.

Well Operations and Pipeline Income

Well operations and pipeline income for the three months ended March 31, 2007, was $3.3 million compared to $2.3 million for the same prior year period, an increase of $1 million. The increase was due to an increase in the number of wells and pipeline systems operated by the Company for our drilling program partnerships as well as third parties.

Oil and Gas Price Risk Management, Net

For the three months ended March 31, 2007, the Company recorded an oil and gas price risk management loss of $5.6 million compared to a gain of $4.9 million for the same period last year, representing a decrease of $10.5 million. For the three months ended March 31, 2007, the Company recorded unrealized losses of $6.2 million and realized gains of $0.6 million compared to unrealized gains of $3.5 million and realized gains of $1.4 million for the same prior year period. The change is a result of a significant decline from record December 31, 2005, pricing to March 31, 2006, in both the Colorado Interstate Gas Index ("CIG") and New York Mercantile Exchange ("NYMEX") markets which increased the value of the Company's floors and resulted in the gains during the first quarter of last year. The CIG pricing increase from December 31, 2006, to March 31, 2007, along with the increased derivative positions and increased production in Colorado resulted in the majority of the unrealized losses recorded in the quarter. These losses were partially offset by gains as a result of decreases in NYMEX pricing for the Company's Appalachian and Michigan Basin properties. Oil and gas price risk management, net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production (this line does not include commodity based derivative transactions related to transactions from marketing activities).

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas and oil prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2008, we have in place a series of floors and ceilings on a portion of our natural gas and oil 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, 2007, the Company averaged natural gas volumes sold of 1.4 Bcf per month and oil sales of 67,000 barrels per month. The positions in effect as of June 29, 2007, on the Company's share of production by area are shown in the following table.

Index

		Floors		Ceilings	
Month Set	Contract Term	Monthly Quantity Gas-Mmbtu Oil-Barrels	Contract Price	Monthly Quantity Gas-Mmbtu Oil-Barrels	Contract Price
Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin)					
Feb-06	May 2007 - Oct 2007	44,000	$ 5.50	-	$ -
Sep-06	May 2007 - Oct 2007	194,500	4.50	-	-
Dec-06	Nov 2007 - Mar 2008	100,000	5.25	-	-
Jan-07	Nov 2007 - Mar 2008	100,000	5.25	100,000	9.80
May-07	Apr 2008 - Oct 2008	197,250	5.50	197,250	10.35
NYMEX Based Derivatives - (Appalachian and Michigan Basins)					
Feb-06	May 2007 - Oct 2007	85,000	7.00	-	-
Feb-06	May 2007 - Oct 2007	85,000	7.50	34,000	10.83
Sep-06	May 2007 - Oct 2007	85,000	6.25	-	-
Jan-07	May 2007 - Oct 2007	85,000	5.25	-	-
Dec-06	Nov 2007 - Mar 2008	144,500	7.00	-	-
Jan-07	Nov 2007 - Mar 2008	144,500	7.00	153,000	13.70
Jan-07	Apr 2008 - Oct 2008	144,500	6.50	153,000	10.80
May-07	Apr 2008 - Oct 2008	120,000	7.00	120,000	13.00
Panhandle Based Derivatives (NECO)					
Feb-06	May 2007 - Oct 2007	60,000	6.00	-	-
Feb-06	May 2007 - Oct 2007	60,000	6.50	60,000	9.80
Jan-07	May 2007 - Oct 2007	90,000	4.50	-	-
Dec-06	Nov 2007 - Mar 2008	70,000	5.75	-	-
Jan-07	Nov 2007 - Mar 2008	90,000	6.00	90,000	11.25
Jan-07	Apr 2008 - Oct 2008	90,000	5.50	90,000	9.85

Jun-07	Apr 2008 - Oct 2008	90,000	6.00	90,000	11.25
DJ Basin					
Jan-07	May 2007 - Oct 2007	161,000	4.00	-	-
Jan-07	Nov 2007 - Mar 2008	90,000	5.25	90,000	9.80
May 2007	Apr 2008 - Oct 2008	216,000	5.50	216,000	10.35
DJ Basin EXCO Property Acquistion					
Jan-07	May 2007 - Oct 2007	60,000	4.00	-	-
Jan-07	Nov 2007 - Mar 2008	30,000	5.25	30,000	9.80
May-07	Apr 2008 - Oct 2008	90,000	5.50	90,000	10.35
Oil - NYMEX Based (Wattenberg/ND)					
Sep-06	May 2007 - Oct 2007	12,350	50.00	-	-

Other Revenues

Other revenues for the three months ended March 31, 2007, were $0.2 million with an immaterial amount for the same prior year period.

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the three months ended March 31, 2007, were $9 million compared to $6.9 million for the three months ended March 31, 2006, an increase of $2.1 million or 30.4%. The increase was primarily attributable to the 45% increase in production volumes and the increased number of wells and pipeline systems operated by the Company as well as costs associated with the Company's purchase of interests in 44 older partnerships. Lifting cost per Mcfe declined from $1.39 to $1.15 per Mcfe, which was primarily due to decreased property and severance taxes on lower sales prices of oil and natural gas.

Index

Exploration Cost

For the three months ended March 31, 2007, exploration costs increased to $2.7 million from $1.2 million for the same prior year period. Exploration costs for the three months ended March 31, 2007, include exploratory dry hole costs of $1.2 million, exploratory department costs of $0.8 million and geological and geophysical costs of $0.5 million.

General and Administrative Expenses

General and administrative expenses for the three months ended March 31, 2007, were $7.4 million compared to $3.7 million for the same prior year period, an increase of $3.7 million. The increase was due to the Company’s increased audit costs, the restatement of the Company sponsored partnerships’ financial statements, increased costs of complying with the various provisions of Sarbanes-Oxley, in particular Section 404 - Internal Controls, accounting assistance from third party consultants and increased payroll and payroll related costs. The Company expects these higher compliance costs to continue throughout 2007.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended March 31, 2007, increased to $13.1 million from $6.6 million for the same prior year period, an increase of $6.5 million. The increase was due to the 45% increase in production, significant investments, totaling $235.9– million, in oil and gas properties by the Company in the first three months of this year, and increased per unit cost of depreciation, depletion and amortization as a result of rising costs of acquisitions and the drilling and equipping of wells.

Interest Income

For the three months ended March 31, 2007, interest income increased to $1.1 million from $0.4 million for the same prior year period. The increase was due to interest earned on the investment of cash proceeds from the sale of undeveloped leaseholds.

Interest Expense

Interest expense for the three months ended March 31, 2007, was $0.8 million compared to $0.4 million for the same prior year period. The increase in interest paid was due to higher average outstanding balances of our credit facility, offset by capitalized construction period interest in both periods. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes was 36.5% which is substantially similar to last year’s rate.

Subsequent Events

In July 2006, the Company and an unaffiliated party entered into a purchase and sale agreement regarding the sale of the Company's undeveloped leasehold located in the Grand Valley Field, Garfield County, Colorado ("PSA"), as filed with the Securities and Exchange Commission ("SEC") as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 2006. On May 31, 2007, the Company and the unaffiliated party entered into a letter agreement amending the PSA. The letter agreement relieves the Company of its obligation, in its entirety, to either drill 16 wells on specifically identified acreage over the next three years, at the Company's cost and the Company's benefit, or pay liquidated damages of $1.6 million per un-drilled well. As a result, the Company will recognize the related, remaining deferred gain on sale of leaseholds of $25.6 million as a gain on the sale of leaseholds in the second quarter of 2007.

Pursuant to the letter agreement, the Company is obligated to drill six wells on specifically identified acreage. These wells will be drilled on unaffiliated party's leasehold for its benefit and at its cost. In addition, the unaffiliated party will return 160 acres of leasehold property acquired from the Company pursuant to the PSA.

Index

The Company is party to an exploration agreement with an unaffiliated party. The agreement requires the Company to drill a minimum of 25 wells through June 30, 2007. For each well the Company fails to drill prior to June 30, 2007, the Company will be required to pay liquidated damages equal to $125,000 per un-drilled well, for a maximum contingency of $3.1 million. During June 2007, the Company determined it would not be able to fulfill its obligation after drilling three wells. The Company was not able to renegotiate the agreement and will pay the liquidating damages. The Company will record the liquidated damages of $2.75 million and an impairment of the $1.1 million carrying value of the cost of the acreage to exploration expense in the second quarter of 2007.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations and use of the Company's credit facility. Operating cash flow is generated by sales of natural gas and oil from the Company's well interests, natural gas marketing, profits from well drilling and operating activities from the Company's drilling programs and others, and natural gas gathering and transportation. Cash payments from Company-sponsored partnerships are used to drill and complete wells for the partnerships, with positive operating cash flow being recognized by the Company to the extent revenues exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities. Such credit arrangements were adequate to meet all cash and liquidity requirements.

Natural Gas Pricing and Pipeline Capacity

The Company sells natural gas under contracts that are priced based on spot prices or price indexes that reflect current market prices for the commodity. As a result, variations in the market are reflected in the revenue we receive. The price of natural gas has varied substantially over short periods of time in the past, and there is every reason to expect a continuation of that variability in the future. During the first three months of 2007, prices for natural gas decreased from the last part of 2006 but were still close to record levels, and future expectations as reflected in NYMEX futures market are for continuing high price levels for the remainder of 2007 and beyond. Strong domestic and international demand for energy and inadequate short term supplies are believed to be key causes of the strong prices. High prices could encourage the development of new energy sources and reduced consumption as users find more efficient ways to use energy or substitute other energy forms. High energy prices could also slow global economic growth, further reducing demand. As a result, the energy price outlook could change rapidly from current expectations. Reduced natural gas prices would reduce the profitability and cash flow from the Company's gas production operations.

Financial results depend upon many factors, particularly the price of natural gas and the Company’s ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company’s financial results. Natural gas and oil 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 can entail a local oversupply situation from time to time. Such a situation currently exists in the Rocky Mountain region, with productive capacity exceeding the local market and pipeline capacity to more distant markets. The result, beginning in the second quarter of 2007, has been a decrease in the price of Rocky Mountain natural gas compared to the NYMEX price and other markets. The Company expects this situation to continue until cold weather returns and/or new pipeline capacity for moving gas from the region is placed in service. In particular, the Rockies Express pipeline, scheduled to go into service in January 2008, would move 1.8 Bcf/day of gas from the region, which is expected to improve the pricing to other markets. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, so their timing is not within its control. Thus, future delivery constraints could result in lower than anticipated prices or production in any of the Company's producing areas.

Oil Pricing

Oil prices have been near or at record levels for most of the last few years and continued into 2007. The Company's oil prices are largely determined by oil prices in the world market. Global supply and demand and geopolitical factors are the key determinants of oil prices. The rapid growth of energy use in developing countries, most notably China, is driving a rapid increase in worldwide oil consumption. Higher prices could result in reduced consumption and/or increasing supplies that could moderate the current high price levels. Over the past several years, oil has been an increasing part of the Company's production mix. As a result, higher oil prices have contributed to the Company's increased revenue from oil and gas sales more than in the past, and the Company would suffer a greater impact if oil prices were to decrease. Oil sales accounted for 26.4% of the Company’s oil and gas sales during the first quarter of 2007.

Index

Oil and Gas Derivative Activities

Because of the uncertainty surrounding natural gas and oil prices, we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2008, we have in place a series of floors and ceilings on part of our natural gas and oil 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. See the section titled "Oil and Gas Derivative Activities" as discussed in our three-month results of operations for a more detailed analysis of the Company's current derivative positions.

The Company uses derivative investments to protect prices for its partners' share of production as well as its own production. Actual wellhead prices will vary based on local contract conditions, gathering and other costs and factors. The Company records the fair value of its partners' share of outstanding derivatives and the partners corresponding obligation or benefit in accounts receivable or other liabilities as appropriate.

The Company's derivative transactions do not currently qualify for hedge accounting under Statement of Financial Accounting Standard No. 133. Therefore, the Company records its derivative gains and losses, both realized and unrealized, through oil and gas price risk management for its share of production. The Company is required to mark-to-market its derivative positions at the end of each period and record the adjustment to the consolidated statement of income under oil and gas price risk management. This may and does cause wide variability in profits from period to period.

During the three months ended March 31, 2006, the Company recognized oil and gas price risk management gains of $4.9 million compared to losses for the three months ended March 31, 2007, of $5.6 million.

Drilling Programs

In September 2006, the Company funded a drilling partnership, Rockies Region 2006 Limited Partnership, with subscriptions of approximately $90 million. Upon closing, the Company, the managing general partner, contributed in cash a total of $38.9 million for its contribution to the total capital of the partnership. After payment of sales commissions and associated expenses, including a management fee of $1.3 million to the Company, the partnership had a total of approximately $118.0 million available for future drilling. Drilling operations commenced in September 2006, and will continue into the second quarter of 2007. All of the 2006 partnership's 97 wells have been drilled as of March 31, 2007, and completion and equipping operations will continue through the second quarter of 2007.

The Company plans another partnership, Rockies Region 2007 Limited Partnership, with a maximum amount of subscriptions of $110 million to be funded, with drilling to commence in the third quarter of 2007 and continuing through the first and second quarters of 2008.

The Company invests, as its equity contribution to each drilling partnership, a sum equal to approximately 43% of the aggregate subscriptions received in the current drilling partnership being offered. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

Substantially all of the Company's drilling programs contain a repurchase provision allowing investors to request that the Company repurchase their partnership units. This repurchase provision is in effect any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is 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 investors request that the Company repurchase the units and subject to the Company's financial ability to do so. The maximum annual 10% contingent repurchase obligation, if requested by the investors, is currently approximately $6.5 million. The Company has adequate liquidity to meet this obligation. During the first three months of 2007, the Company paid $0.3 million under this provision for the repurchase of partnership units.

Index

Drilling Activity

During the three months ended March 31, 2007, the Company and its drilling fund partnership drilled a total of 56 developmental wells as detailed by field below. Wells labeled as program wells were drilled for the benefit of the Company and its drilling fund partnership in which the Company has approximately a 37% working interest, while wells labeled as non-program were drilled for the benefit of the Company.

	Development Wells		
	Successful	Dry	Total
Program			
Wattenburg	19	1	20
Piceance	3	-	3
	22	1	23
Non Program			
Wattenburg	7	-	7
Piceance	13	-	13
NECO	12	1	13
	32	1	33
Total			
Wattenburg	26	1	27
Piceance	16	-	16
NECO	12	1	13
	54	2	56

Additionally, during the three months ended March 31, 2007, the Company drilled for the benefit of the Company and its drilling fund partnership, five exploratory wells. Two of these wells were drilled on the Company's North Dakota Nesson acreage and three wells were drilled on the Colorado Wattenburg acreage. Of the five exploratory wells, two were determined to be dry, one in each field.

Oil and Gas Properties

Costs incurred by the Company in oil and gas property acquisition, exploration and development for the three months ended March 31, 2007, are presented below:

	Amounts *(in thousands)*
Acquisition of properties:	
Unproved properties	$ 18,685
Proved properties	197,558
Development costs	15,876
Exploration costs	3,792
Total costs incurred	$ 235,911

Common Stock Buyback Program

On October 16, 2006, the Board of Directors of the Company approved a stock purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at time and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. For the three months ended March 31, 2007, the Company purchased 2,666 shares at a cost of $137,123 ($51.43 average price per share). In May 2007, the Company purchased 3,663 shares at a cost of $183,406 ($50.07 average price per share).

Index

Working Capital

The Company's working capital as of March 31, 2007, is negative $70.0 million. The Company manages its working capital needs by only drawing from its credit facility of $200 million as liabilities come due and cash is required. At March 31, 2007, the Company had an activated line of credit with an additional borrowing capacity of $40 million. As of March 31, 2007, the Company has adequate liquidity with the credit facility to meet both its working capital requirements and plans for continued investment in oil and gas well drilling.

Long-Term Debt

The Company has a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. Effective May 25, 2007, the Company's current borrowing base, based upon current oil and gas reserves, was increased from $100 million to $135 million, which is fully activated. The Company is required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at the discretion of the Company. 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 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. No principal payments are required until the credit agreement expires on November 4, 2010.

On December 19, 2006, the Company executed pursuant to its credit facility an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.80% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January 2007.

As of March 31, 2007, the outstanding balance under the facility, including the overline note, was $60 million compared to $117 million, excluding the overline note discussed above, as of December 31, 2006. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. At March 31, 2007, an outstanding balance of $60 million was subject to a prime interest rate of 8.25%. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves and the maintenance of certain working capital and tangible net worth ratios. At March 31, 2007, the Company was not in compliance with its current ratio covenant. As of the filing of this quarterly report, the Company was not in compliance with the requirement to timely file its March 31, 2007, Form 10-Q. The Company has received a waiver from the banks for the current ratio covenant violation at March 31, 2007, and was granted a waiver related to the delay in the delivery of its March 31, 2007, interim condensed consolidated financial statement until June 30, 2007.

Index

Contractual Obligations and Contingent Commitments

The following table represents the contractual obligations of the Company as of March 31, 2007.

		Payments due by period			
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Debt	$ 60,000	$ -	$ -	$ 60,000	$ -
Operating Leases	2,000	508	978	514	-
Asset Retirement Obligations	16,936	50	200	200	16,486
Drilling Rig Commitments	32,958	12,556	19,925	477	-
Derivative Agreements (1)	4,240	3,192	1,048	-	-
Other Liabilities	7,694	120	2,211	120	5,243
Total	$ 123,828	$ 16,426	$ 24,362	$ 61,311	$ 21,729

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(1) Amount represents gross liability related to fair value of derivatives. Includes fair value of derivatives for RNG, Petroleum Development Corporation's share of oil and gas production and derivatives contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The Company has a net receivable from the partnerships of $1.4 million as of March 31, 2007.

Long-term debt in the above table does not include interest because interest rates are variable and principal balances fluctuate significantly from period to period. The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and cost efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

Commitments and Contingencies

As managing general partner of 32 partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes its and its subcontractors' casualty insurance coverage is adequate to meet this potential liability.

Recent Accounting Pronouncements

See Note 2, *Recent Accounting Standards*, to the Condensed Consolidated Financial Statements.

Disclosure Regarding Forward Looking Statements

This 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 the Company's estimate of the sufficiency of its existing capital sources, its 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, its ability to sell its produced natural gas and oil and the prices it receives for its production, its 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 gas business. In particular, careful consideration should be given to cautionary statements made in this Form 10-Q, the Company's Annual Report on Form 10-K for the year ended December 31, 2006, and the Company's other SEC filings and public disclosures. The Company undertakes no duty to update or revise these forward-looking statements.

Index

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents, designated cash and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, short-term certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of March 31, 2007, is $74 million with an average interest rate of 4.07%. As of March 31, 2007, the Company had long-term debt of $60 million subject to a prime interest rate of 8.25%.

Commodity Price Risk

The Company utilizes commodity based derivative instruments to manage a portion of its exposure to price risk from its oil and natural gas sales and marketing activities. Company policy prohibits the use of oil and natural gas future and option contracts for speculative purposes. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for NECO production and CIG-based contracts for other Colorado production. The Company purchases puts and participating collars for its own and affiliate partnerships production to protect against possible price instability in future periods while retaining much of the benefits of price increases. In the case of RNG, these derivative instruments have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the derivative relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these derivatives are structured to reduce the Company's exposure to changes in price associated with the derivative commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the derivative commodity. RNG also enters into fixed-price physical purchase and sale agreements that are derivative contracts.

The net fair value of the commodity based derivatives was $4.4 million and $13.6 million at March 31, 2007 and December 31, 2006, respectively. The Company recognized in the statement of income an unrealized loss on commodity based derivatives of $6.6 million for the three months ended March 31, 2007, and unrealized gains of $2.9 million for the three months ended March 31, 2006.

See Note 15, Derivative Financial Instruments, to the condensed consolidated financial statements, for a summary of the open derivative option and purchase and sales contracts for RNG and the Company as of March 31, 2007.

In addition to including the gross assets and liabilities related to the Company's share of oil and gas production, the summary of open derivative positions presented in Note 15 to the condensed consolidated financial statements and the accompanying consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The accompanying consolidated balance sheets include the fair value of derivatives and a corresponding net receivable from the partnerships of $2.1 million as of March 31, 2007, and a net payable to the partnerships of $7.5 million as of December 31, 2006. In addition to the short-term fair value of derivatives shown in the accompanying consolidated balance sheet there are long-term assets and long-term liabilities which total to a net long-term liability of approximately $0.1 million as of March 31, 2007, and a net long-term asset of approximately $0.9 million as of December 31, 2006, respectively, related to the fair value of derivatives included in the accompanying consolidated balance sheets.

The average CIG closing price for natural gas per Mmbtu for the three months ended March 31, 2007, and for the year 2006, was $5.58 and $7.21, respectively. The average NYMEX closing price for natural gas per Mmbtu for the three months ended March 31, 2007, and for the year 2006, was $6.77 and $7.23, respectively. The average NYMEX closing price for oil per bbl for the three months ended March 31, 2007, and for the year 2006, was $57.81 and $64.73, respectively. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

Index

Item 4. Controls and Procedures

Material Weaknesses Previously Disclosed

As discussed in our 2006 Annual Report on Form 10-K, we did not maintain effective controls as of December 31, 2006, over (1) timely reconciliation, review and adjustment of significant balance sheet and income statement accounts, (2) proper accounting for the identification of certain derivative contracts to adequately determine the derivative's fair value, and (3) proper accounting for oil and gas properties for capitalization of costs and that the calculations of depreciation and depletion were performed accurately.

Evaluation of Disclosure Controls and Procedures

As of March 31, 2007, the Company carried out an evaluation under the supervision and with the participation of Management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in Securities Exchange Act of 1934, 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 the Company files or submits under the Exchange Act is 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 CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, the CEO and the CFO concluded that as a result of the material weaknesses cited above, our disclosure controls and procedures were not effective as of March 31, 2007. Because of these material weaknesses, the Company performed additional procedures to ensure that our financial statements as of and for the quarter ended March 31, 2007, 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 2007 and through the filing of this Form 10-Q, the Company implemented the following changes in internal control over financial reporting:

- Reinforced reconciliation procedures to ensure the timely reconciliation, review and adjustments to significant balance sheet and income statement accounts;
- Progressed in the development of more extensive policies and procedures concerning the controls over financial reporting for derivatives;
- Provided additional training regarding derivatives for key management personnel;
- Developed a review process to ensure proper accounting for oil and gas properties, specifically the capitalization of costs and calculation of depreciation and depletion.

The Company continues to evaluate the ongoing effectiveness and sustainability of the changes the Company has 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

From time to time the Company is a party to various legal proceeding in the ordinary course of business. While it is not possible to determine with any degree of certainty the ultimate outcome of the following legal proceedings, the Company believes that it has meritorious defenses with respect to the claims asserted against it and intends to vigorously defend its position. An adverse outcome in this case or any similar case could have a material adverse effect, individually and collectively, on the Company's financial position and results of operations.

Index

Royalty Payments. 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 the Company underpaid royalties on gas produced from wells operated by the Company 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 made by the Company to the plaintiff pursuant to leases. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, the Company is unable to predict the ultimate outcome of this suit at this time.

Litigation similar to the Droegemueller Action has recently been commenced against several other companies in jurisdictions where the Company conducts business. While the Company's 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.

Other. The Company is involved in various other legal proceedings that it considers normal to its business. While it is not feasible to predict the ultimate outcome of such other proceedings, the Company believes that the ultimate outcome of such other proceedings will not have a material adverse effect on its financial position or results of operations.

Item 1A. Risk Factors

The Company faces many risks. Factors that could materially adversely affect the Company’s business, financial condition, operating results or liquidity and the trading price of common stock are described under “Risks Related to the Oil and Natural Gas Industry and the Company” in Item 1A of our annual report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on May 23, 2007. This information should be considered carefully, together with other information in this report and other reports and materials the Company file with the SEC. There have been no material changes from the risk factors previously disclosed in the Company’s 2006 Form 10-K.

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, 2007	2,666	$ 51.43	2,666	1,474,443
Total	2,666	51.43	2,666	1,474,443

32

Index

On October 16, 2006, the Board of Directors of the Company approved a stock purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at time and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. For the three months ended March 31, 2007, the Company purchased 2,666 shares at a cost of $137,123 ($51.43 average price per share). In May 2007, the Company purchased 3,663 shares at a cost of $183,406 ($50.07 average price per share).

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

Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description
31.1	Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer.
31.2	Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer.
32	Title 18 U.S.C. Section 1350 (Section 906 of Sarbanes-Oxley Act of 2002) Certifications by Chief Executive Officer and Chief Financial Officer of Petroleum Development Corporation.

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: June 29, 2007

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

Date: June 29, 2007

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