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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 period ended March 31, 2006

OR

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

Commissions file number 0-7246

I. R. S. Employer Identification Number 95-2636730

PETROLEUM DEVELOPMENT CORPORATION
(A Nevada Corporation)
103 East Main Street
Bridgeport, WV 26330
Telephone: (304) 842-6256

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: 16,125,613 shares of the Company's Common Stock ($.01 par value) were outstanding as of May 31, 2006.

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 AND SUBSIDIARIES

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PART I - FINANCIAL INFORMATION

Report of Independent Registered Public Accounting Firm

The Board of Directors
Petroleum Development Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of March 31, 2006, the related condensed consolidated statements of income for the three-month periods ended March 31, 2006 and 2005, and the related condensed consolidated statements of cash flows for the three-month periods ended March 31, 2006 and 2005, and related condensed consolidated statement of stockholders' equity for the three-month period ended March 31, 2006. These condensed consolidated financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical review procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U. S. generally accepted accounting principles.

We have previously audited, in accordance with standards of Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of December 31, 2005, and the related consolidated statements of income, stockholders' equity and cash flows for the year then ended (not presented herein); and in our report dated May 24, 2006, we expressed an unqualified opinion on those consolidated financial statements. As discussed in that report, the consolidated financial statements as of December 31, 2004 and 2003, and for each of the years in the two year period ended December 31, 2004 have been restated and the report also included an explanatory paragraph referring to a change in accounting for asset retirement obligations in 2003. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2005, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

As discussed in note 11 to the condensed consolidated financial statements, the Company has restated the condensed consolidated statement of income for the three month period ended March 31, 2005.

KPMG LLP

Pittsburgh, Pennsylvania
June 30, 2006

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets
March 31, 2006 and December 31, 2005

Assets	2006	2005
	(Unaudited)	
Current assets:		
Cash and cash equivalents	$ 80,530,000	$ 90,110,100
Restricted cash	964,300	1,500,600
Accounts receivable	34,419,000	49,779,500
Accounts receivable - affiliates	2,144,700	7,233,800
Inventories	4,344,200	5,054,900
Fair value of derivatives	2,342,700	10,381,800
Other current assets	4,732,100	4,640,500
Total current assets	129,477,000	168,701,200
Properties and equipment	410,238,100	388,764,100
Less accumulated depreciation, depletion and amortization	118,187,700	111,605,900
	292,050,400	277,158,200
Other assets	1,973,000	3,225,500
Total Assets	$423,500,400	$449,084,900

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued
March 31, 2006 and December 31, 2005

Liabilities and Stockholders' Equity	2006	2005
	(Unaudited)	
Current liabilities:		
Accounts payable and accrued expense	$ 96,481,600	$ 107,762,300
Fair value of derivatives	4,869,100	18,424,400
Advances for future drilling contracts	22,033,600	49,999,400
Funds held for future distribution	23,288,400	18,346,300
Total current liabilities	146,672,700	194,532,400
Long-term debt	44,000,000	24,000,000
Other liabilities	6,119,300	7,115,500
Deferred income taxes	27,910,700	26,888,500
Asset retirement obligation	8,648,700	8,283,200
Total liabilities	233,351,400	260,819,600
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 16,057,065 and 16,281,923 shares	160,500	162,800
Additional paid-in capital	19,686,700	30,422,900
Retained earnings	170,301,800	158,504,200
Unamortized stock award	-	(824,600)
Total stockholders' equity	190,149,000	188,265,300
Total Liabilities and Stockholders' Equity	$ 423,500,400	$ 449,084,900

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Income
Three Months Ended March 31, 2006 and 2005
(Unaudited)

	2006	2005 (Restated)(2)
Revenues:		
Oil and gas well drilling operations (1)	$ 5,278,100	$ 25,366,300
Gas sales from marketing activities	41,941,500	17,522,000
Oil and gas sales	29,208,300	18,663,700
Well operations and pipeline income	2,289,900	1,927,100
Other income	390,800	6,213,800
Total revenues	79,108,600	69,692,900
Costs and expenses:		
Cost of oil and gas well drilling operations (1)	4,215,600	20,644,100
Cost of gas marketing activities	41,775,400	17,901,600
Oil and gas production and well operations cost	7,104,500	3,978,100
Exploratory dry hole costs	1,078,300	-
General and administrative expenses	3,980,200	1,617,500
Depreciation, depletion, and amortization	6,616,300	4,856,900
Total costs and expenses	64,770,300	48,998,200
Income from operations	14,338,300	20,694,700
Interest expense	179,900	147,800
Oil and gas price risk management (gain) loss, net	(4,435,100)	3,659,100
Income before income taxes	18,593,500	16,887,800
Income taxes	6,795,900	6,247,900
Net income	$ 11,797,600	$ 10,639,900
Basic earnings per common share	$ 0.73	$ 0.64
Diluted earnings per common share	$ 0.73	$ 0.64

(1) See Note 9.
(2) See Note 11.

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statement of Stockholders' Equity
Three Months ended March 31, 2006
(Unaudited)

	Common Stock Issued				Treasury	Unamortized	
	Number of Shares	Amount	Additional Paid-In-Capital	Retained Earnings	Stock at Cost	Stock Award	Total
Balance, December 31, 2005	16,281,923	$162,800	$30,422,900	$158,504,200	$ -	$ (824,600)	$188,265,300
Reclassification of unearned compensation pursuant to FAS 123R adoption			(824,600)			824,600	
Exercise of employee stock options, net of tax	8,000	100	31,000	-	-	-	31,100
Stock award	25,311	200	(200)	-	-	-	-
Amortization of stock award	-	-	207,900	-	-	-	207,900
Purchase of treasury stock	-	-	-	-	(10,152,900)	-	(10,152,900)
Treasury stock retirement	(258,169)	(2,600)	(10,150,300)	-	10,152,900	-	-
Net income	-	-	-	11,797,600	-	-	11,797,600
Balance, March 31, 2006	16,057,065	$160,500	$19,686,700	$170,301,800	$ -	$ -	$190,149,000

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows
Three Months Ended March 31, 2006 and 2005
(Unaudited)

	2006	2005
Cash flows from operating activities:		
Net income	$ 11,797,600	$ 10,639,900
Adjustments to net income to reconcile to cash provided by operating activities:		
Deferred federal income taxes	1,022,200	1,524,400
Depreciation, depletion & amortization	6,616,300	4,856,900
Accretion of asset retirement obligation	107,400	115,000
Exploratory dry hole costs	1,078,300	-
Gain from sale of assets	(2,500)	(5,163,100)
Expired and abandoned leases	17,000	9,100
Amortization of stock award	207,900	117,200
Unrealized (gain) loss on derivative transactions	(2,411,100)	4,147,500
Decrease in current assets	16,883,400	4,966,400
Decrease in other assets	5,100	13,000
(Decrease) increase in current liabilities	(33,312,300)	13,273,700
Increase (decrease) in other liabilities	868,600	(870,400)
Net cash provided by operating activities	2,877,900	33,629,600
Cash flows from investing activities:		
Capital expenditures	(23,025,300)	(20,099,500)
Proceeds from sale of leases to partnerships	708,800	195,500
Proceeds from sale of assets	2,500	6,168,200
Net cash used in investing activities	(22,314,000)	(13,735,800)
Cash flows from financing activities:		
Proceeds from debt	49,000,000	18,000,000
Retirement of debt	(29,000,000)	(21,000,000)
Payment of debt issuance costs	(22,100)	-
Proceeds from stock option exercises	31,000	-
Purchase and cancellation of treasury stock	(10,152,900)	-
Net cash provided by (used in) financing activities	9,856,000	(3,000,000)
Net (decrease) increase in cash and cash equivalents	(9,580,100)	16,893,800
Cash and cash equivalents, beginning of period	90,110,100	77,735,300
Cash and cash equivalents, end of period	$ 80,530,000	$ 94,629,100

See accompanying notes to unaudited condensed consolidated financial statements.

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 drilling 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 footnotes and other financial information included in audited financial statements were 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, 2006, 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 unaudited 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, 2005, as filed with the SEC on May 31, 2006.

As described in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, we restated our condensed consolidated statements of income for each of the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005. The restatement was to correct certain revenues and expenses to properly reflect the elimination of transactions between the Company and Company-sponsored limited partnerships. The corrections resulted in the reduction of revenues and expenses of equal amounts. The restatement had no effect on net income, earnings per share, cash flow, proved oil and gas reserves or the Company's financial position. No amounts labeled as restated have been changed subsequent to the Company filing its 2005 Annual Report on Form 10-K. See Note 11 for further disclosure.

2. Accounting Policies

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. In addition, the Company offers its drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships, and hence, different revenue recognition policies pursuant to EITF 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.*

Cost-plus drilling service arrangements were initially entered into in late 2005 with drilling activity commencing in early 2006. Although the Company acts as a principal in the transaction and takes title to products and services acquired necessary for drilling, the Company acts as an agent, with little risk of loss during the performance of the drilling activities. Consistent with the provisions of EITF 99-19, the Company's services provided under the cost-plus drilling agreements are recognized net of recovered costs.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services and accordingly has risk of loss in performing services under these arrangements. As such, the Company recognizes revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that our estimated costs exceed the estimated contract revenue. As of March 31, 2006, the Company has a loss contract reserve of $800,000, which was recorded in late 2005.

Natural gas marketing is recorded on the gross accounting method. Riley Natural Gas (RNG), our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. RNG has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the realized and unrealized portions of the RNG commodity based derivative transactions for natural gas marketing activities are included in gas sales from marketing activities or cost of gas marketing activities, as applicable.

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold by the Company under contracts with terms ranging from one month to three years. Virtually all of the Company's contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Company currently uses the "net-back" method of accounting for transportation arrangements of our natural gas sales. The Company sells gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by our customers and reflected in the wellhead price.

Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered in a stock tank, collection of revenue from the sale is reasonably assured and the sales price is determinable. The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company's crude oil production is sold to purchasers at or near the Company's wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

Well operations and pipeline income is recognized when persuasive evidence of an arrangement exists, services have been rendered, collection of revenues is reasonably assured and the sales price is fixed or determinable. The Company is paid a monthly operating fee for each well it operates for outside owners including the limited partnerships sponsored by the Company. The fee covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

Stock Based Compensation

The Company accounts for stock based compensation pursuant to SFAS 123(R) - *Share-Based Payment.* SFAS 123(R), which requires an entity to recognize at the grant date, the fair value of stock options and other equity-based compensation issued to employees in the statement of income. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in the Company's consolidated statements of income. Compensation expense attributable to granted awards are recognized using the straight-line method over the vesting period of the entire award.

The Company utilizes a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. The Company's determination of fair value of share-based payment awards on the date of grant using the model is affected by the Company's stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to the Company's expected stock price volatility over the expected term of the awards, and actual and projected employee stock option exercise behaviors. In addition, forfeitures are required to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Although the fair value of employee stock options is determined in accordance with SFAS 123(R) and SAB 107 using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company is responsible for determining the assumptions used in estimating the fair value of its share-based payment awards.

3. Stock-Based Compensation

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (SFAS 123(R)) to account for stock-based employee compensation. Among other items, SFAS 123(R) eliminates the use of APB Opinion No. 25 (APB 25) and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in our financial statements on a straight-line basis over the vesting period for the entire award. Amounts are recognized in general and administrative expense and oil and gas production and well operations cost in the condensed consolidated statements of income. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated for the adoption of SFAS 123(R) under the modified prospective method.

The adoption of SFAS 123(R) required the unearned compensation recorded under APB 25 related to stock-based compensation awards as of January 1, 2006, in the amount of $824,600 to be eliminated against additional paid-in-capital.

For the three months ended March 31, 2006 and 2005, we recorded the following stock-based compensation:

	Restricted Stock		Stock Options		Total	
	2006	2005	2006	2005	2006	2005
Oil and gas production and well operations cost	$ 34,400	$ -	$ -	$ -	$ 34,400	$ -
General and administrative expenses	132,500	73,800	41,000	-	173,500	73,800
Total	$ 166,900	$ 73,800	$ 41,000	-	$ 207,900	$ 73,800

For the quarter ended March 31, 2006, the adoption of SFAS 123(R) resulted in a reduction in income before income taxes in the amount of $207,900. SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (excess tax benefits) to be classified as financing cash inflows in our statements of cash flows.

Prior to January 1, 2006, we accounted for our employee stock options using the intrinsic value method prescribed by APB 25. The adoption of SFAS 123(R) had an immaterial effect on the Company's net income and earnings per share for the quarter ended March 31, 2006. The table below provides the effect on net income and earnings per share had the Company used the fair value based method to record stock-based compensation for the three months ended March 31, 2005:

Net Income:	
As reported	$ 10,639,900
Add: Stock-based compensation expense included in reported net income, net of tax	73,800
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of tax	(97,600)
Pro forma net income	$ 10,616,100
Basic earnings per common share:	
As reported	$ 0.64
Pro forma	$ 0.64
Diluted earnings per common share:	
As reported	$ 0.64
Pro forma	$ 0.63

The fair value of options awarded is estimated using the Black-Scholes option pricing model using the assumptions noted in the following table. Expected volatility is 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 and is restricted from doing so based on its current credit facility. The Company did not grant any option awards in 2005.

	Three Months Ended March 31, 2006
Expected volatility	39.5%
Expected life (in years)	5.9
Risk-free interest rate	4.3%
Dividend yield	0%
Weighted-average grant date fair value per share	$18.92

Restricted Stock

The Company began issuing shares of restricted common stock to employees in 2004. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, ratably over four years from the date of grant for employees and three years for directors.

The following table provides a summary of restricted stock activity for the three months ended March 31, 2006:

	Restricted Shares		Weighted Average Grant-Date Fair Value
Non-vested restricted stock at December 31, 2005	38,430	$	1,256,000
Granted	25,311		1,107,000
Vested	-		-
Forfeited	-		-
Non-vested restricted stock at March 31, 2006	63,741	$	2,363,000

As of March 31, 2006, there was $1.7 million of total unrecognized compensation cost related to non-vested restricted stock. The cost is expected to be recognized over a weighted average period of four years.

Stock Options

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 following table provides information related to stock option activity for the three months ended March 31, 2006.

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Average Intrinsic Value (a)
Outstanding at December 31, 2005	73,880	$ 11.96		
Granted	20,354	43.74		
Exercised	(8,000)	3.86		
Forfeited or expired	-	-		
Outstanding March 31, 2006	86,234	$ 20.21	5.9	$ 2,168,800
Exercisable at March 31, 2006	53,220	$ 7.18	5.9	$ 2,031,900

(a) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during the quarter ended March 31, 2006, was $280,700. There were no options exercised during the quarter ended March 31, 2005.

As of March 31, 2006, there was $519,400 of total unrecognized compensation cost related to non-vested stock options. The cost is expected to be recognized over a weighted average period of 2.5 years.

4. Oil and Gas Properties

Oil and Gas Properties are reported on the successful efforts method.

5. Earnings Per Share

Computation of earnings per common and common equivalent share is as follows for the three months ended March 31, 2006 and 2005:

	2006	2005
Weighted average common shares outstanding	16,054,368	16,589,824
Dilutive effect of share-based compensation:		
Unamortized portion of restricted stock	18,125	1,906
Stock options	66,565	51,158
Weighted average common and common equivalent shares outstanding	16,139,058	16,642,888
Net income	$ 11,797,600	$ 10,639,900
Basic earnings per common share	$ 0.73	$ 0.64
Diluted earnings per common share	$ 0.73	$ 0.64

At March 31, 2006 and 2005, there were no shares outstanding that were antidilutive.

During the second quarter of 2006 through June 28, 2006, the Company awarded restricted common stock shares totaling 74,394 to certain employees and officers in accordance with its long-term equity compensation plan.

6. Suspended Well Costs

The following table provides a summary of capitalized exploratory well costs for the three months ended March 31, 2006.

	Amount	Number of Wells
Beginning balance at December 31, 2005	$ 1,918,400	2
Additions to capitalized exploratory well costs pending the determination of proved reserves	7,071,700	6
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(5,809,500)	(6)
Capitalized exploratory well costs charged to expense	-	-
Ending balance at March 31, 2006	$ 3,180,600	2

At March 31, 2006, none of the wells awaiting the determination of proved reserves have been capitalized for a period greater than three months.

7. Business Segments

The Company's operating activities is 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, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 2,800 wells from which it derives oil and gas working interests. 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, 2006 and 2005, is as follows (in thousands):

	2006	2005
REVENUES		(Restated)(4)
Drilling and Development	$ 5,278	$ 25,366
Natural Gas Marketing	42,107	17,582
Oil and Gas Sales	29,208	18,664
Well Operations and Pipeline Income	2,290	1,927
Unallocated amounts (1)(2)	226	6,153
Total	$ 79,109	$ 69,692

	2006	2005
SEGMENT INCOME (LOSS) BEFORE INCOME TAXES		(Restated)(4)
Drilling and Development	$ 1,063	$ 4,722
Natural Gas Marketing	329	(321)
Oil and Gas Sales (3)	20,809	7,019
Well Operations and Pipeline Income	419	1,230
Unallocated amounts (2)		
General and Administrative expenses	(3,980)	(1,618)
Interest expense	(180)	(148)
Other (1)	134	6,004
Total	$ 18,594	$ 16,888

	March 31, 2006	December 31, 2005
SEGMENT ASSETS		
Drilling and Development	$ 83,940	$ 89,030
Natural Gas Marketing	28,128	56,518
Oil & Gas Sales	270,899	256,621
Well Operations and Pipeline Income	26,715	31,407
Unallocated amounts (2)		
Cash	347	3,383
Other	13,471	12,126
Total	$ 423,500	$ 449,085

(1) Includes interest on investments and partnership management fees, and during the three months ended March 31, 2005, includes a lease sale with a gain of $5.2 million.
(2) Items which are not allocated in assessing segment performance.
(3) Includes $1,078 in exploratory dry hole costs for the three months ended March 31, 2006.
(4) See Note 11 for further discussion.

8. Commitments and Contingencies

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas and oil sales to a few customers. The Company sells natural gas to various public utilities, natural gas marketers, industrial and commercial customers.

The Company is exposed to 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. Such nonperformance is not anticipated. There were no counterparty default losses in first quarter 2006 or the year 2005.

Substantially all of the Company's drilling programs contain a repurchase provision where investors may request the Company to repurchase 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 month’s cash distributions), only if investors request the Company to repurchase such units, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by investors, is currently approximately $10.8 million. The Company believes it has adequate liquidity to meet this obligation should it arise. During 2005 and the first three months of 2006, the Company paid $351,700 and $105,900, respectively, under this provision for the repurchase of partnership units.

The Company's drilling programs formed since 1996 contain a performance supplement that requires the Company to remit a payment equal to one-half of its share of net revenue from the partnership to the investing partners if certain levels of performance are not met. During the three months ended March 31, 2006 and 2005, the Company paid partnerships a total of $195,700 and $124,200, respectively in accordance with the provision. As of March 31, 2006, based upon current oil and gas reserve reports of the partnerships with this provision, the maximum amount of this contingency is $4.5 million.

As managing general partner of 75 partnerships, the Company is liable 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 drilling rigs, the Company made commitments to the drilling contractors which call for a minimum commitment of $24,000 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 $55,400 daily for a specified amount of time for daily use of the drilling rigs. As of March 31, 2006, commitments for these three separate contracts expire in May 2008, July 2009 and May 2010. As of March 31, 2006, the Company has an outstanding minimum commitment for $22.2 million, and an outstanding maximum commitment for $58.2 million.

From time to time the Company is a party to various legal proceedings in the ordinary course of business. The Company is not currently a party to any litigation that it believes would have a materially adverse effect on the Company's business, financial condition, results of operations, or liquidity.

9. Drilling Revenues and Costs of Oil and Gas Drilling Operations

As described in Note 2, the Company changed the type of drilling arrangement it has with its sponsored partnerships. The Company switched, effective with the last partnership of 2005, which started drilling in first quarter 2006, from a footage-based contract to a cost-plus contract. The elimination of risk of loss with the new cost-plus contracts does not allow the Company to record revenue for the total contract price of the arrangement but only the gross profit from the contract. The new cost-plus contract impacted first quarter 2006 by reducing drilling revenues and drilling costs by $17.5 million.

10. Common Stock Buyback Program

On January 13, 2006, the Company publicly announced that its Board of Directors authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. The following activity has occurred since inception of the plan on January 13, 2006, until June 28, 2006.

Month of Purchase	January 2006
Average Price Paid per Share	$39.33
Broker/Dealer	McDonald Investments
Number of Shares Purchased	258,169
Remaining Number of Shares Subject to Purchase	1,369,331

11. 2005 Restatement

As described in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, we restated our condensed consolidated statements of income for each of the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005. The restatement was to correct certain revenues and expenses to properly reflect the elimination of transactions between the Company and Company-sponsored limited partnerships. The corrections resulted in the reduction of revenues and expenses of equal amounts. The restatement had no effect on net income, earnings per share, cash flow, proved oil and gas reserves or the Company's financial position. No amounts labeled as restated have been changed subsequent to the Company filing its 2005 Annual Report on Form 10-K.

The following table sets forth the effect of the restatement on the affected line items within the Company's previously reported condensed consolidated statement of income for the quarter ended March 31, 2005 (unaudited, in thousands).

Condensed Consolidated Statements of Income Data:	Three Months Ended March 31, 2005 As previously reported	As restated
Revenues:		
Oil and gas well drilling operations	$ 32,351	$ 25,366
Well operations and pipeline income	2,112	1,927
Total revenues	76,863	69,693
Costs and expenses:		
Cost of oil and gas well drilling operations	$ 27,629	$ 20,644
Oil and gas production and well operations costs	4,163	3,978
Total costs and expenses	56,168	48,998
Income from operations	$ 20,695	$ 20,695

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

Management Overview

As described in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, we restated our condensed consolidated statements of income for each of the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005. The restatement was to correct certain revenues and expenses to properly reflect the elimination of transactions between the Company and Company sponsored limited partnerships. The corrections resulted in the reduction of revenues and expenses of equal amounts. The restatement had no effect on net income, earnings per share, cash flow, proved oil and gas reserves or the Company's financial position. No amounts labeled as restated have been changed subsequent to the Company filing its 2005 Annual Report on Form 10-K. See Note 11 to Condensed Consolidated Financial Statements.

The Company recorded strong revenues, income and cash flow for the first three months of 2006 and 2005. High oil and natural gas prices in combination with record Company production were the largest contributors to both income and cash flow. The high energy prices increased the Company's revenues both for sales of Company-owned production and for gas purchased and sold by RNG, our natural gas marketing subsidiary. Management also believes that high energy prices make the Company's partnership investment programs more attractive to investors.

Profitability in the first three months of 2006 was increased by gains in the Petroleum Development Corporation's derivative transactions in the amount of $4.4 million as recorded in the "Oil and gas price risk management" line item in the income statement. The gains included both realized and unrealized gains. Realized gains are cash gains incurred at the maturity of derivatives positions which amounted to $1.4 million during the three months ended March 31, 2006. Unrealized gains, which amounted to $3.0 million during the three months ended March 31, 2006, reflect possible gains on derivative positions maturing in future periods, and may increase or decrease depending on the level of gas and oil prices at the date the derivatives mature or on the date they are closed, whichever occurs first.

The increased profitability, continued positive cash flow from operations and borrowings allowed the Company to continue to invest in capital projects. The majority of capital investment was for oil and gas drilling and development activities.

Results of Operations

Three Months Ended March 31, 2006, Compared with March 31, 2005

Revenues

Total revenues for the three months ended March 31, 2006, were $79.1 million compared to a restated $69.7 million for the three months ended March 31, 2005, an increase of approximately $9.4 million or 13.5 percent. The increase was primarily the result of increased oil and gas sales from both gas marketing activities and the Company's share of production, offset in part by a decline in drilling revenues. See Note 9 to the condensed consolidated financial statements for the impact the new cost-plus drilling arrangements and related accounting had on our operating revenues for first quarter 2006.

Costs and Expenses

Costs and expenses for the three months ended March 31, 2006, were $64.8 million compared to a restated $49.0 million for the three months ended March 31, 2005, an increase of approximately $15.8 million or 32.2 percent. The increase was primarily the result of increased cost of gas marketing activities, oil and gas production and well operations costs, exploratory dry hole costs, general and administrative expenses, and depreciation, depletion and amortization, offset in part by a decrease in well drilling costs. See Note 9 to the condensed consolidated financial statements for the impact the new cost-plus drilling arrangements and related accounting had on our cost of oil and gas well drilling operations for first quarter 2006.

Drilling Operations

During first quarter 2006, the Company, in addition to its footage-based drilling arrangements, began recognizing revenues for its cost-plus service arrangements with its partnerships. The cost-plus drilling arrangements became effective with the private program partnership funded by the Company on December 30, 2005. Total oil and gas well drilling operations for the three months ended March 31, 2006, was $5.3 million, net of $17.5 million of costs related to drilling arrangements accounted for on the cost-plus basis, compared to a restated $25.4 million for the same period in 2005, a decrease of $20.1 million or 79.1 percent. See Note 9 to the condensed consolidated financial statements.

The new cost-plus contract impacted first quarter 2006 by reducing drilling revenues and drilling costs by $17.5 million, as outlined in the table below (in millions):

	Three months ended March 31,			
	2006			2005
	Drilling Service Revenue	Direct Reimbursed Cost	Reimbursement from Partnerships	Drilling Service Revenue
Oil and gas well drilling	$ 5.3	$ 17.5	$ 22.8	$ 25.4
Total revenues	$ 79.1	$ 17.5	$ 96.6	$ 69.7
Cost of oil and gas well drilling	$ 4.2	$ 17.5	$ 21.7	$ 20.6
Total costs and expenses	$ 64.8	$ 17.5	$ 82.3	$ 49.0
Income from operations	$ 14.3	$ -	$ 14.3	$ 20.7

The cost of oil and gas well drilling operations for the three months ended March 31, 2006, was $4.2 million compared to a restated $20.6 million for the three months ended March 31, 2005, a decrease of $16.4 million. The decrease in costs is primarily attributable to the Company's revenue recognition accounting for its new cost-plus drilling arrangements, which reduced drilling costs by $17.5 million for the quarter ended March 31, 2006. See Note 9 to the condensed consolidated financial statements.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's marketing subsidiary for the three months ended March 31, 2006, were $41.9 million compared to $17.5 million for the three months ended March 31, 2005, an increase of approximately $24.4 million or 139 percent. The increase was the result of higher volumes sold and unrealized gains on derivative transactions of $8.7 million for the three months ended March 31, 2006, compared to an unrealized loss of $6.8 million for the three months ended March 31, 2005.

The costs of gas marketing activities for the three months ended March 31, 2006, were $41.8 million compared to $17.9 million for the three months ended March 31, 2005, an increase of $23.9 million or 134 percent. The increase was due to higher average volumes of natural gas purchased for resale and significantly higher average purchase prices and unrealized losses on derivative transactions of $9.3 million for the three months ended March 31, 2006, compared to an unrealized gain of $6.1 million for the three months ended March 31, 2005. Income before income taxes for the Company's natural gas marketing subsidiary increased from a loss of $321,000 for the three months ended March 31, 2005, to a profit of $329,000 for the three months ended March 31, 2006. Based on the nature of RNG's gas marketing activities, derivatives did not have a significant impact on its net margins from marketing activities during either period.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended March 31, 2006, were $29.2 million compared to $18.7 million for the three months ended March 31, 2005, an increase of $10.5 million or 56.1 percent. The increase was due to increased volumes sold at significantly higher average sales prices of oil and natural gas. The volume of natural gas sold for the three months ended March 31, 2006, was 2.9 Bcf at an average sales price of $7.24 per Mcf compared to 2.7 Bcf at an average sales price of $5.27 per Mcf for the three months ended March 31, 2005. Oil sales were 127,700 barrels at an average sales price of $63.55 per barrel for the three months ended March 31, 2006, compared to 100,900 barrels at an average sales price of $44.19 per barrel for the three months ended March 31, 2005. The increase in oil and natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, wells drilled in our Northeast Colorado (NECO) area of operation, and the investment in oil and gas properties we own in our drilling program partnerships.

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, 2006			Three Months Ended March 31, 2005		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	489	408,425	411,359	1,099	451,052	457,646
Michigan Basin	1,089	356,292	362,826	982	412,548	418,440
Rocky Mountains	126,135	2,147,963	2,904,773	98,815	1,832,635	2,425,525
Total	127,713	2,912,680	3,678,958	100,896	2,696,235	3,301,611
Average Sales Price	$63.55	$7.24	$7.94	$44.19	$5.27	$5.65

*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 our ability to market our production effectively. In recent years, natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on our financial results. Natural gas prices in the Rocky Mountain Region continue to trail prices which we receive for our Appalachian and Michigan gas. The Company's management believes the lower prices in the Rocky Mountain Region, including Colorado, reflect the higher costs to move gas to major market areas compared to Michigan and the Appalachian Basin resulting in a lower price compared to the eastern areas. In May 2003, a pipeline expansion project was completed, leading to improved natural gas prices in the region which reduced the local surplus. There is currently a substantial amount of drilling activity in the Rockies, and if future additions to the pipeline system are not made in a timely fashion it is possible that pipeline constraints could create a local oversupply situation in the future which could mean lower natural gas prices. Like most other producers in the area we rely on major interstate pipeline companies to construct these facilities, so their timing and construction is not within our control.

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2007, we have in place a series of floors and ceilings on a portion of our natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. During the three months ended March 31, 2006, the Company averaged natural gas volumes sold of 970,900 Mcf per month and oil sales of 42,600 barrels per month. The positions in effect as of June 28, 2006, on the Company's share of production by area are shown in the following table.

		Floors		Ceilings	
Month Set	Contract Term	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin)					
Mar-05	Apr 2006 – Oct 2006	42,000	$4.50	21,000	$7.25
Jul-05	Apr 2006 – Oct 2006	27,500	5.50	13,750	7.63
Jul-05	Nov 2006 – Mar 2007	27,500	6.00	13,750	8.40
Feb-06	Nov 2006 – Mar 2007	60,000	6.50	–	–
Feb-06	Apr 2007 – Oct 2007	44,000	5.50	–	–

		Floors		Ceilings	
Month Set	Contract Term	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
NYMEX Based Derivatives - (Appalachian and Michigan Basins)					
Mar-05	Apr 2006 – Oct 2006	78,000	$5.50	39,000	$7.40
Jul-05	Apr 2006 – Oct 2006	61,000	6.25	30,000	8.98
Jul-05	Nov 2006 – Mar 2007	68,000	7.00	34,000	9.27
Feb-06	Nov 2006 – Mar 2007	34,000	8.00	–	–
Feb-06	Nov 2006 – Mar 2007	34,000	8.50	34,000	13.73
Feb-06	Apr 2007 – Oct 2007	34,000	7.00	–	–
Feb-06	Apr 2007 – Oct 2007	34,000	7.50	34,000	10.83
Panhandle Based Derivatives (NECO)					
Mar-05	Apr 2006 – Oct 2006	150,000	$5.00	75,000	$8.62
Jul-05	Nov 2006 – Mar 2007	150,000	6.50	75,000	8.56
Feb-06	Apr 2007 – Oct 2007	60,000	6.00	–	–
Feb-06	Apr 2007 – Oct 2007	60,000	6.50	60,000	9.80

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, 2006, were $7.1 million compared to a restated $4.0 million for the three months ended March 31, 2005, an increase of approximately $3.1 million or 77.5 percent. The increase was due to increased production costs and severance and property taxes on the increased volumes and significantly higher sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting cost increased from $1.03 to $1.53 per Mcfe due to increased severance and property taxes on the significantly increased oil and gas prices along with additional well workovers and production enhancement work performed.

Exploratory Dry Hole Costs

In first quarter 2006, the Company identified one exploratory dry hole in the Red Desert Basin in Wyoming and recognized the related dry hole costs of $829,700 in the same period. Additional second quarter 2006 dry hole costs for this well are estimated to be $300,000. The Company previously identified and reported six exploratory dry holes in 2005. Additional costs for these dry holes were incurred in first quarter 2006 in the amount of $248,600. The Company does not expect to recognize any material additional cost related to these dry wells in future periods.

Well Operations and Pipeline Income

Well operations and pipeline income for the three months ended March 31, 2006, was $2.3 million compared to a restated $1.9 million for the three months ended March 31, 2005, an increase of approximately $400,000 or 21.1 percent. 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.

Other Income

Other income for the three months ended March 31, 2006, was $390,800 compared to $6.2 million for the three months ended March 31, 2005, a decrease of $5.8 million. The decrease is a result of a sale in January 2005 of a portion of one of our undeveloped leases in Garfield County, Colorado, which we sold for a pre-tax profit of $5.2 million. In addition, the 2005 period included $599,100 in management fees collected from the funding of our 2005-A drilling partnership.

General and Administrative Expenses

General and administrative expenses for the three months ended March 31, 2006, increased to $4.0 million compared to $1.6 million for the three months ended March 31, 2005, an increase of approximately $2.4 million or 150.0 percent. The increase was primarily due to increased costs of complying with the various provisions of Sarbanes-Oxley, in particular Section 404 (Internal Controls), the cost of the Company's financial statement restatements and increased payroll and payroll related expenses.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended March 31, 2006, increased to $6.6 million from approximately $4.9 million for the three months ended March 31, 2005, an increase of approximately $1.7 million or 34.7 percent. The increase was due to the increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest expense for the three months ended March 31, 2006, was $180,000 compared to $148,000 for the three months ended March 31, 2005, an increase of $32,000 or 21.6 percent. Such increase is due to rising interest rates and higher average outstanding balances of our credit facility. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of interest expense. The average outstanding debt balance for the three months ended March 31, 2006, was $2.7 million compared to $867,000 for the three months ended March 31, 2005.

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

Oil and gas price risk management (gain) loss, net for the three months ended March 31, 2006, was a gain of $4.4 million compared to a $3.7 million loss for the three months ended March 31, 2005, an increase of $8.1 million. For the three months ended March 31, 2006, the Company recorded unrealized gains of $3.0 million and realized gains of $1.4 million compared to the three months ended March 31, 2005, which is comprised of unrealized losses of $3.5 million and realized losses of $200,500. The Company's strategy in its derivative policy is to provide protection on declining oil and natural gas prices. The Company has experienced a declining oil and natural gas pricing environment in 2006. This trend resulted in the Company recognizing gains in its derivative transactions in 2006. In a rising oil and natural gas pricing environment the Company would in theory record losses in its derivative transaction activities. Oil and gas price risk management (gain) loss, net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production. This line item does not include commodity based derivative transactions related to transactions from our gas marketing activities of RNG.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes declined from approximately 37 percent to 36.6 percent. Such decline is due to certain one time income tax expenses during 2005.

Net Income and Earnings Per Share

Net income for the three months ended March 31, 2006, was $11.8 million compared to a net income of $10.6 million for the three months ended March 31, 2005, an increase of approximately $1.2 million or 11.3 percent.

Basic and diluted earnings per common share for the three months ended March 31, 2006, were $0.73 per share compared to $0.64 per share for the three months ended March 31, 2005, an increase of $0.09 per share or 14.1 percent. The increase is the result of increased net income as well as a decrease in the number of common shares outstanding.

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 operating cash flow accruing to 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 2006 prices for natural gas decreased slightly from the last part of 2005 but were still close to or above record levels, and future expectations as reflected in the New York Mercantile Exchange (NYMEX) futures market are for continuing high price levels for the remainder of 2006 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.

Natural gas prices throughout the country are generally closely related allowing for differences in the quality and energy content of the gas, the location and distance to market, and other factors. However, it is not uncommon for prices in a particular area to vary from historical relationships. This may occur when a local condition restricts the marketability of the natural gas. For example limits on pipeline delivery capacity for natural gas can result in lower than normal prices for wells that use the system to deliver gas to market. This situation occurred in 2002 to 2003 in the Rocky Mountains, when the productive capacity of wells in the region exceeded the amount of gas that could be used by local markets or shipped out of the area. In order to access the available capacity, producers were forced to sell their gas at lower than normal prices with the alternative being to shut wells in. Since that time, additional pipeline capacity has been added, and further additions are planned in the future, so prices have returned to the historical relationship to other producing regions. 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 were near or above record levels for most of 2005 and continue through the first quarter of 2006. 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 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 2007, we have in place a series of floors and ceilings on part of our natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor, the counterparty pays us. See the section titled "Oil and Gas Derivative Activities" as discussed in our result 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.

Drilling Programs

In December, 2005, the Company commenced sales and funded its third 2005 partnership, a private limited partnership, Rockies Region Private Limited Partnership with subscriptions of approximately $36 million. Drilling operations commenced in the first quarter of 2006. This is the first partnership under the "cost plus" arrangement (see note 9). Although the Company offered and funded a drilling program in the first quarter of 2005, the Company has not yet done so in 2006, resulting in a decreased cash flow from operations for the quarter ended March 31, 2006. The next drilling program is planned for the third quarter of 2006.

The Company invests, as its equity contribution to each drilling partnership, a sum equal to approximately 32% of the aggregate subscriptions received for that particular drilling partnership. 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. The Company posts daily, during the subscription period of a partnership, the amount of subscriptions that have been sold in the partnership at its website, www.petd.com under the heading of "Drilling Program."

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% repurchase obligation, if requested by the investors, is currently approximately $10.8 million. The Company has adequate liquidity to meet this obligation. During the first three months of 2006, the Company paid $105,900 under this provision for the repurchase of partnership units.

Drilling Activity

During the three months ended March 31, 2006, the Company and its drilling fund partnerships drilled a total of 47 wells with one developmental dry hole. The Company drilled 37 successful wells and one dry hole in Wattenberg Field in the Denver-Julesburg Basin and eight successful wells in the Piceance Basin in western Colorado. An exploratory dry hole was drilled in the Red Desert Basin in Wyoming. The Company plans to conduct its 2006 partnership and its own drilling activities in these three areas.

Additionally, the Company drilled several development wells outside of the drilling fund partnerships. The Company participated in a well on its northeast Colorado property which was drilled by a joint venture partner. The Company drilled two Piceance Basin wells and one well in Michigan for its own account. The Company drilled one exploratory well on its North Dakota Bakken acreage as well as participated in two exploratory wells on its North Dakota Nesson acreage.

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, 2006, are presented below:

Acquisition of properties:	
Unproved properties	$ 5,302,400
Proved properties	105,900
Development costs	8,120,100
Exploration costs	8,150,000
Total costs incurred	$21,678,400

Common Stock Buyback Program

On January 13, 2006, the Company publicly announced that its Board of Directors has authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. The following activity has occurred since inception of the plan on January 13, 2006, until June 28, 2006.

Month of Purchase	January 2006
Average Price Paid per Share	$39.33
Broker/Dealer	McDonald Investments
Number of Shares Purchased	258,169
Remaining Number of Shares Subject to Purchase	1,369,331

Working Capital

Although the Company's working capital as of March 31, 2006, is a negative $17.2 million, this amount includes a net current liability of $2.5 million related to the fair value of derivatives. The amount may or may not be realized depending on the change in the fair value of derivatives upon settlement, and if realized, will be funded with proceeds from future oil and gas sales. 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, 2006, 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 over the next year.

Long-Term Debt

The Company has a credit facility with J. P. Morgan Chase Bank, NA (formerly Bank One, NA) and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. The current borrowing base, based upon current oil and gas reserves, is $125 million of which the Company has activated $80 million of the facility. The Company is required to pay a commitment fee of 0.25 to 0.375 percent per annum on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on November 4, 2010. There were no significant changes to the credit facility during the quarter ended March 31, 2006.

As of March 31, 2006, the outstanding balance was $44 million compared to $24 million as of December 31, 2005. The increase of approximately $20 was related to capital expenditures of approximately $23 million in the first quarter of 2006. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of specified working capital and tangible net worth ratios along with a restriction on the payment of dividends. At March 31, 2006, the outstanding balance was subject to a prime rate of 7.75%. As of the filing of this Form 10-Q, the Company is in compliance with all covenants in the credit agreement, except for timely filing of this March 31, 2006, Form 10-Q. The Company has received bank waivers to extend the due date of the March 31, 2006, condensed consolidated financial statements until June 30, 2006.

Contractual Obligations and Contingent Commitments

Contractual obligations and contingent commitments and due dates are as follows (in thousands):

	Payments due by period				
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 44,000	$ -	$ -	$ 44,000	$ -
Operating Leases	1,323	322	587	392	22
Asset Retirement Obligations	8,699	50	100	100	8,449
Drilling Rig Commitment	58,241	20,221	31,922	6,098	-
Derivative Agreements (1)	6,630	4,869	1,761	-	-
Partnership Performance Supplement (2)	4,516	964	3,100	410	42
Other Liabilities	3,526	40	250	250	2,986
Total	$ 126,935	$ 26,466	$ 37,720	$ 51,250	$ 11,499

(1) Amount represents gross liability related to fair value of derivatives. Includes fair value of derivatives for Riley Natural Gas, 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 corresponding receivable from the partnerships of $1.6 million as of March 31, 2006.

(2) Represents maximum amount the Company would be required to pay to investing partners if certain levels of partnership performance are not met as of March 31, 2006 (see Note 8).

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 75 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.

Factors That May Affect Future Results and Financial Conditions

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under "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, 2005, as filed with the Securities and Exchange Commission on May 31, 2006. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to our business operations and the understanding of our results of operations. This is not a comprehensive list of all of our accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by accounting principles generally accepted in the United States, with no need for management's judgment in their application. There are also areas in which management's judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and may require the application of significant judgment by our management; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, our management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on our historical experience, our observation of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see "Note 1 - Summary of significant accounting policies" in our annual financial statements and related notes on Form 10-K. Our critical accounting policies and estimates are as follows:

Principles of Consolidation

The accompanying condensed consolidated financial statements include the accounts of Petroleum Development Corporation (PDC) and its wholly owned subsidiaries, Riley Natural Gas and PDC Securities Incorporated. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in interests in oil and gas limited partnerships under the proportionate consolidation method. Under this method, the Company's financial statements include its pro rata share of assets, liabilities and revenues and expenses respectively of the Company sponsored limited partnerships in which it participates. The Company's proportionate share of all significant transactions between the Company and the Company-sponsored limited partnerships are eliminated.

Revenue Recognition

The Company's drilling segment recognizes revenue from drilling contracts with its sponsored drilling programs using the percentage of completion method. These contracts range in term from three to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision for the drilling and completion process and uses subcontractors to perform drilling and completion services. Revenues are recognized under the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed periodically during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that our estimated costs exceed the estimated contract revenue. As of March 31, 2006, the Company has a loss contract reserve of $800,000, which was recorded in late 2005.

The Company offers its drilling services under two types of contractual arrangements, cost-plus fee or footage-based drilling contracts, which result in differing risk and reward relationships and, hence, differing revenue recognition polices.

Our cost-plus drilling service arrangements were initially entered into in late 2005 with drilling activity commencing in early 2006. Although the Company acts as a principal in the transaction and takes title to products and services acquired necessary for drilling, the Company acts as an agent, with little risk of loss during the performance of the drilling activities. Consistent with the provisions of EITF 99-19, the Company’s services provided under the cost-plus drilling agreements are recognized net of recovered costs.

Our footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services and accordingly has risk of loss in performing services under these arrangements. As such, the Company recognizes revenue under these agreements gross of related expenses.

Natural gas marketing is recorded on the gross accounting method. RNG, our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. RNG has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the realized and unrealized portions of the RNG commodity based derivative transactions for natural gas marketing activities are included in gas sales from marketing activities or cost of gas marketing activities, as applicable.

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold by the Company under contracts with terms ranging from one month to three years. Virtually all of the Company’s contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company’s revenues from the sale of natural gas suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Company currently uses the "net-back" method of accounting for transportation arrangements of our natural gas sales. The Company sells gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by our customers and reflected in the wellhead price.

Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered in a stock tank, collection of revenue from the sale is reasonably assured and the sales price is determinable. The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company’s crude oil production is sold to purchasers at or near the Company’s wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

Well operations and pipeline income is recognized when persuasive evidence of an arrangement exists, services have been rendered, collection of revenues is reasonably assured and the sales price is fixed or determinable. The Company is paid a monthly operating fee for each well it operates for outside owners, including the limited partnerships sponsored by the Company. The fee covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

Valuation of Accounts Receivable

Management reviews accounts receivable to determine which are doubtful of collection. In making the determination of the appropriate allowance for doubtful accounts, management considers the Company's history of write-offs, relationships and overall credit worthiness of its customers, and well production data for receivables related to well operations.

Accounting for Derivatives Contracts at Fair Value

The Company uses derivative instruments to manage its commodity and financial market risks. Accounting requirements for derivatives and hedging activities are complex; interpretation of these requirements by standard-setting bodies is ongoing.

Derivatives are reported on the Condensed Consolidated Balance Sheets at fair value. Changes in fair value of derivatives are recorded in earnings in the condensed consolidated statements of income as none of the Company's derivatives qualified for hedge accounting under the provisions of FAS No. 133.

The measurement of fair value is based on actively quoted market prices, if available. Otherwise, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based on valuation methodologies considered appropriate by the Company's management. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value.

Use of Estimates in Long-Lived Asset Impairment Testing

Impairment testing for long-lived assets and intangible assets with definite lives is required when circumstances indicate those assets may be impaired. In performing an impairment test, the Company estimates the future cash flows associated with individual assets or groups of assets. Impairment is recognized when the undiscounted estimated future cash flows are less than the related asset's carrying amount. In those circumstances, the asset must be written down to its fair value, which, in the absence of market price information, may be estimated as the present value of its expected future net cash flows, using an appropriate discount rate. Although cash flow estimates used by the Company are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Oil and Gas Properties

The Company accounts for its oil and gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and development dry hole costs are depreciated or depleted by the unit-of-production method based on estimated proved developed producing oil and gas reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved oil and gas reserves. The Company obtains new reserve reports from independent petroleum engineers annually as of December 31st of each year. The Company adjusts oil and gas reserves for any major acquisitions, new drilling and divestitures during the year as needed.

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing its reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of our financial statements, the costs are expensed to exploratory dry hole costs. If we are unable to make a final determination about the productive status of a well prior to issuance of our financial statements, the well is classified as "Suspended Well Costs" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well's productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded. The determination of an exploratory well's ability to produce is made within one year from the completion of drilling activities.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved oil and gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to expense. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on the Company's historical experience, acquisition dates and average lease terms. Amortization of remaining lease costs for all other insignificant properties is recorded over the average remaining lives of the leases. The valuation of unproved properties is subjective and requires management of the Company to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

Upon sale or retirement of significant portions of or complete fields of depreciable or depletable property, the book value thereof, less proceeds or salvage value, is credited or charged to income. Upon sale of individual wells, the proceeds are credited to property costs.

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which management reasonably estimates such products to be sold. These estimates of future product prices may differ from current market prices of oil and gas. Any downward revisions to management's estimates of future production or product prices could result in an impairment of the Company's oil and gas properties in subsequent periods. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Deferred Tax Asset Valuation Allowance

Deferred tax assets are recognized for deductible temporary differences, net operating loss carry-forwards, and credit carry-forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset is not expected to be realized under the preceding criteria, a valuation allowance will be established.

The judgments used in applying the above policies are based on management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

Recently Adopted Accounting Standards

In December 2004, the FASB issued SFAS 153, "Exchange of Nonmonetary Assets", an amendment of APB Opinion 29, "Accounting for Nonmonetary Transactions". This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance for transactions in fiscal periods that begin after June 15, 2005. The adoption of the provisions of SFAS 153 did not have a material impact on the Company’s condensed consolidated financial statements.

In June 2005, the FASB issued SFAS 154, "Accounting Changes and Error Corrections" - a replacement of APB Opinion No. 20 and FASB Statement No. 3, which replaces Accounting Principles Board Opinion (APB) No. 20, "Accounting Changes", and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements", and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle in addition to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of the provisions of SFAS 154 in the first quarter of 2006 did not have a material impact on the Company’s condensed consolidated financial statements.

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment", to account for stock-based employee compensation. Among other items, SFAS 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated for the adoption of SFAS 123(R) under the modified prospective method. See Note 3 to condensed consolidated financial statements for a discussion of the adoption of SFAS 123(R) and its impact on the Company's 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, 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 and in the various reports the Company has filed with the Securities and Exchange Commission. The Company undertakes no duty to update or revise these forward-looking statements.

Item 3. Quantitative and Qualitative Disclosure About Market Risk.

Interest Rate Risk

There have been no material changes in the reported market risks faced by the Company since December 31, 2005.

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. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts traded by BNP Paribas for NECO production and CIG-based contracts traded by JP Morgan for other Colorado production. 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. Riley Natural Gas also enters into fixed-price physical purchase and sale agreements that are derivative contracts. The Company's policy prohibits the use of oil and natural gas future and option contracts for speculative purposes.

The following tables summarize the open derivative and fixed-price purchase and sale positions for Riley Natural Gas and Petroleum Development Corporation as of March 31, 2006 and 2005.

Riley Natural Gas
Open Derivative Positions

Commodity	Type	Quantity Gas-Mmbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of March 31, 2006					
Natural Gas	Cash Settled Futures / Swaps Purchases	762,000	$ 7.97	$ 6,075,892	$ (213,953)
Natural Gas	Cash Settled Futures / Swaps Sales	2,625,000	7.81	20,504,140	(1,467,922)
Natural Gas	Cash Settled Basis Swap Sales	200,000	0.50	100,000	35,500
Natural Gas	Physical Purchases	2,355,000	8.42	19,825,892	660,300
Natural Gas	Physical Sales	373,953	10.66	3,985,024	895,605
Natural Gas	Physical Basis Purchases	200,000	0.45	90,000	(25,500)
Contracts Maturing in 12 months following March 31, 2006					
Natural Gas	Cash Settled Futures / Swaps Purchases	762,000	$ 7.97	$ 6,075,892	$ (213,953)
Natural Gas	Cash Settled Futures / Swaps Sales	2,247,000	7.86	17,654,590	(885,327)
Natural Gas	Cash Settled Basis Swap Sales	200,000	0.50	100,000	35,500
Natural Gas	Physical Purchases	1,867,000	8.65	16,152,422	(238,371)
Natural Gas	Physical Sales	373,953	10.66	3,985,024	895,605
Natural Gas	Physical Basis Purchases	200,000	0.45	90,000	(25,500)
Prior Year Total Contracts as of March 31, 2005					
Natural Gas	Cash Settled Sale	3,947,000	$ 6.10	$ 24,072,530	$ (6,875,781)
Natural Gas	Cash Settled Purchase	710,000	6.48	4,602,990	1,007,870
Natural Gas	Cash Settled Sale Option	320,000	5.42	-	6,492
Natural Gas	Cash Selttled Purchase Option	160,000	7.06	-	(150,218)
Natural Gas	Physical Contract Sale	553,211	7.82	4,325,544	(489,742)
Natural Gas	Physical Contract Purchase	3,928,100	6.40	25,149,432	6,543,287

The maximum term for the derivative contracts listed above is 39 months.

Petroleum Development Corporation
Open Derivative Positions

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of March 31, 2006					
Natural Gas	Cash Settled Option Sales	5,890,000	$ 9.09	$ 53,523,600	$ (4,074,234)
Natural Gas	Cash Settled Option Purchases	14,820,000	6.10	90,460,000	987,344
Contracts maturing in 12 months following March 31, 2006					
Natural Gas	Cash Settled Option Sales	4,770,000	$ 8.77	$ 41,826,600	$ (3,430,982)
Natural Gas	Cash Settled Option Purchases	11,040,000	6.03	66,590,000	1,336,669
Prior Year Total Contracts as of March 31, 2005					
Natural Gas	Purchase	35,100	$ 6.58	$ 230,802	$ 46,554
Natural Gas	Sale Option	6,328,416	4.72	-	259,811
Natural Gas	Purchase Option	3,164,208	7.08	-	(4,305,774)
Crude Oil	Sale Option	118,341	32.30	-	3,818
Crude Oil	Purchase Option	59,171	40.00	-	(981,930)

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 natural 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 includes the negative fair value of derivatives and a corresponding receivable from the partnerships of $1.6 million as of March 31, 2006, and $5.4 million as of December 31, 2005. In addition to the short-term fair value of derivatives shown on the accompanying condensed consolidated balance sheets there is a long-term liability of approximately $676,500 as of March 31, 2006, and $1.3 million as of December 31, 2005, related to the fair value of derivatives included in accompanying balance sheets. See "Working Capital" in Management's Discussion of Liquidity and Capital Resources for the effect of these contracts on the Company's condensed consolidated balance sheets.

The average NYMEX closing price for natural gas for the first quarter of 2006 and the year 2005 was $8.98 Mmbtu and $8.62 Mmbtu, respectively. The average NYMEX closing price for oil for the first quarter of 2006 and the year 2005 was $61.97 bbl and $55.34 bbl, 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.

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company's reports under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, and the Company's Audit Committee and Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

In connection with the preparation of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 ("2005 10-K"), an evaluation was performed under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act). The Company concluded that control deficiencies in its internal control over financial reporting as of December 31, 2005 constituted material weaknesses within the meaning of the Public Company Accounting Oversight Board's Auditing Standard No. 2.

The material weaknesses identified by the Company were disclosed in its 2005 10-K, which was filed with the SEC on May 31, 2006. Based on that and subsequent evaluations, the Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 2006, the Company's disclosure controls and procedures were not effective as a result of the previously-identified material weaknesses in internal control over financial reporting.

(b) Changes and Remediation in the Company's Internal Control over Financial Reporting

There have been no changes in the Company's internal control over financial reporting during the fiscal quarter ended March 31, 2006, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting. See continued remediation effects discussed below.

As reported in Item 9A(c) of the 2005 10-K, the Company determined that material weaknesses in internal control over financial reporting existed as of December 31, 2005. These material weaknesses also existed as of March 31, 2006, and therefore are reported in this Form 10-Q as follows:

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to properly account for derivative transactions in accordance with generally accepted accounting principles. Specifically, the Company's policies and procedures relating to derivatives transactions were not designed effectively to ensure that each of the requirements for hedge accounting was evaluated appropriately with respect to the Company's commodity based derivatives. Additionally, the Company's policies and procedures relating to the derivative transactions entered into on behalf of affiliated partnerships were not adequate to ensure these transactions were recorded properly in the financial statements. As a result, a misstatement was identified in the fair value of derivatives and the oil and gas price risk management loss accounts that was corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure compliance with appropriate accounting principles for its oil and gas properties. Specifically, the Company's policies and procedures were not designed effectively to ensure that the calculation of depreciation and depletion and the determination of impairments were performed in accordance with the applicable authoritative accounting guidance. As a result, misstatements were identified in the accumulated depreciation, depletion and amortization and the depreciation, depletion and amortization expense accounts that were corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure proper accounting and disclosure for income taxes. Specifically, the Company's policies and procedures did not provide for appropriate control documentation or supervisory review of permanent and temporary differences, or assessment of tax reserves to ensure that they were properly reflected and disclosed in the Company's financial statements. As a result, misstatements were identified in the deferred income tax liability and income tax expense accounts that were corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure that its accounting for asset retirement obligations complied with generally accepted accounting principles. Specifically, the Company's policies and procedures regarding the estimate of the fair value of the asset retirement obligations were not designed effectively to ensure that it was estimated in accordance with FAS No. 143, *Asset Retirement Obligations*. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to provide for adequate monitoring and assessment of the application of accounting principles, standards or rules as it relates to proportionate consolidation in a timely manner. As a result of this control deficiency, the Company did not appropriately eliminate its proportionate share of transactions with the Company sponsored limited partnerships, which resulted in the restatement of the Company's financial statements for the first three quarters of 2005, the years ended December 31, 2004, 2003, 2002, and 2001 and each of the quarters in 2004 and 2003.

Remediation of Material Weaknesses in Internal Control

Management, with oversight from the Audit Committee of the Board of Directors, has been addressing the material weakness disclosed in its 2005 Form 10-K and is committed to effectively remediating known weaknesses as expeditiously as possible. Due to the fact that these remedial steps have not been completed, the Company performed additional analysis and procedures in order to ensure that the consolidated financial statements contained in this Form 10-Q were prepared in accordance with generally accepted accounting principles in the United States of America. Although the Company's remediation efforts are well underway, control weaknesses will not be considered remediated until new internal controls over financial reporting are implemented and operational for a sufficient period of time to allow for effective testing and are tested, and management and its independent registered certified public accounting firm conclude that these controls are operating effectively.

As of the date of this filing, the remediation initiatives management has and will continue to implement include:

- The Company continued to enhance its financial accounting and reporting team. An additional Certified Public Accountant was hired in first quarter of 2006, and a financial reporting director was hired during second quarter of 2006. As previously reported during 2005, the Company enhanced training for its financial accounting and reporting team; additional training is being planned for later in 2006.
- The Company engaged a team of highly experienced advisors in first quarter of 2006 to assist with various accounting research, projects and monitoring activities. They assist the Company with accounting and reporting issues including, but not limited to, derivatives, oil and gas activities, new accounting standards or rules, SEC reporting and on-going monitoring of changes that may impact the Company's application of accounting principles.
- During 2005 and continuing in first quarter of 2006, the Company reevaluated and corrected its documentation, policies and procedures, and templates with respect to its accounting for derivatives, depreciation, depletion and amortization, and income taxes and the related disclosures in its financial statements. The Company plans to make additional improvements during second quarter of 2006.
- The Company has evaluated, selected and began planning for the implementation of a third-party integrated oil and gas accounting software system during first quarter 2006. Implementation of the system is planned for later in the year.

The Company believes the measures taken to date and planned for the future will address the reported material weaknesses and intends to complete the remediation efforts during 2006. In addition, the Company will continue to develop and implement other initiatives during 2006 that will further improve both the effectiveness and efficiency of the Company's internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The Company is not a party to any legal actions that would materially affect the Company's operations or financial statements.

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

(c) Purchases of Certain Equity Securities by the Issuer and Others.

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, 2006 - January 31, 2006	258,169	$39.33	258,169	1,369,331
February 1, 2006 – February 28, 2006	-	-	-	1,369,331
March 1, 2006 – March 31, 2006	-	-	-	1,369,331
Total	258,169	$39.33	258,169	1,369,331

On January 13, 2006, the Company publicly announced that its Board of Directors has authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. 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.

Item 6. Exhibits

(a) Exhibits

Exhibit Name	Exhibit Number	Location
Acknowledgement of Independent Registered Public Accounting Firm	23. 1	Filed herewith
Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer	31. 1	Filed herewith.
Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer	31. 2	Filed herewith.
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	32	Filed herewith.

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 30, 2006

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

Date: June 30, 2006

/s/ Darwin L. Stump
Darwin L. Stump
Chief Financial Officer