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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, 2005

OR

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

Commission file number 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 _XX_ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 16,589,824 shares of the Company's Common Stock ($.01 par value) were outstanding as of April 30, 2005.

Indicate by check mark whether the registrant is an accelerated filer (as definition in Rule 12b-2 of the Exchange Act). Yes _XX_ No

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

INDEX

PART I - FINANCIAL INFORMATION

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, 2005, the related condensed consolidated statements of income for the three-month periods ended March 31, 2005 and 2004, and the related condensed consolidated statements of cash flows for the three-month periods ended March 31, 2005 and 2004. These condensed consolidated financial statements are the responsibility of the Company's management.

We conducted our reviews 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 reviews, 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, 2004, 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 March 30, 2005, we expressed an unqualified opinion on those consolidated financial statements in a report that 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, 2004 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

KPMG LLP

Pittsburgh, Pennsylvania
May 5, 2005

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets
March 31, 2005 and December 31, 2004

ASSETS

	2005 (Unaudited)	2004
Current assets:		
Cash and cash equivalents	$ 94,629,100	$ 77,735,300
Accounts and notes receivable	29,931,700	33,902,800
Inventories	3,837,600	1,657,300
Prepaid expenses	3,861,200	7,334,200
Total current assets	132,259,600	120,629,600
Properties and equipment	328,230,100	308,348,200
Less accumulated depreciation, depletion, and amortization	93,144,200	88,341,300
	235,085,900	220,006,900
Other assets	729,300	756,500
	$368,074,800	$ 341,393,000

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued
March 31, 2005 and December 31, 2004

LIABILITIES AND STOCKHOLDERS' EQUITY

	2005 (Unaudited)	2004
Current liabilities:		
Accounts payable and accrued expenses	$70,355,300	$ 65,756,800
Advances for future drilling contracts	54,421,100	42,497,300
Funds held for future distribution	15,404,400	12,911,800
Total current liabilities	140,180,800	121,165,900
Long-term debt	18,000,000	21,000,000
Other liabilities	5,071,700	3,927,500
Deferred income taxes	30,209,300	29,843,200
Asset retirement obligations	794,600	783,500
Stockholders' equity:		
Common stock par value $0.01 per share; authorized 50,000,000 shares; issued and outstanding 16,589,824 shares and 16,589,824 shares	165,800	165,800
Additional paid-in capital	37,684,300	37,684,300
Retained earnings	143,447,600	130,109,800
Unamortized stock award	(764,800)	(882,000)
Accumulated other comprehensive loss, net	(6,714,500)	(2,405,000)
Total stockholders' equity	173,818,400	164,672,900
	$368,074,800	$341,393,000

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Income
Three Months ended March 31, 2005 and 2004
(Unaudited)

	2005	2004
Revenues:		
Oil and gas well drilling operations	$32,351,200	$29,499,300
Gas sales from marketing activities	24,301,000	23,457,400
Oil and gas sales	18,463,200	16,196,200
Well operations and pipeline income	2,112,400	1,837,500
Other income	6,213,800	58,100
	83,441,600	71,048,500
Costs and expenses:		
Cost of oil and gas well drilling operations	27,629,000	25,355,700
Cost of gas marketing activities	23,991,700	22,854,700
Oil and gas production costs	4,163,400	3,906,100
General and administrative expenses	1,617,500	994,200
Depreciation, depletion, and amortization	4,825,000	4,507,700
Interest	43,900	243,500
	62,270,500	57,861,900
Income before income taxes	21,171,100	13,186,600
Income taxes	7,833,300	4,747,200
Net income	$13,337,800	$8,439,400
Basic earnings per common share	$0.80	$0.53
Diluted earnings per common share	$0.80	$0.52

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, 2005 and 2004
(Unaudited)

	2005	2004
Cash flows from operating activities:		
Net income	$13,337,800	$ 8,439,400
Adjustments to net income to reconcile to cash provided by (used in) operating activities:		
Deferred federal income taxes	3,109,800	2,786,600
Depreciation, depletion & amortization	4,825,000	4,507,700
Accretion of asset retirement obligation	11,100	9,000
(Gain)/loss from sale of assets	(5,163,100)	3,000
Leasehold acreage expired or surrendered	9,100	51,000
Amortization of stock award	117,200	900
Decrease (increase) in current assets	4,966,400	(20,600)
Decrease in other assets	13,000	18,800
Increase (decrease) in current liabilities	13,273,700	(28,915,700)
(Decrease) increase in other liabilities	(870,400)	168,900
Total adjustments	20,291,800	(21,390,400)
Net cash provided by (used in) operating activities	33,629,600	(12,951,000)
Cash flows from investing activities:		
Capital expenditures	(20,099,500)	(1,825,800)
Proceeds from sale of leases to partnerships	195,500	624,100
Proceeds from sale of assets	6,168,200	22,400
Net cash used in investing activities	(13,735,800)	(1,179,300)
Cash flows from financing activities:		
Net retirement of long-term debt	(3,000,000)	(11,000,000)
Proceeds from stock option exercises	-	1,685,700
Repurchase and cancellation of treasury stock	-	(1,294,600)
Net cash used in financing activities	(3,000,000)	(10,608,900)
Net increase (decrease) in cash and cash equivalents	16,893,800	(24,739,200)
Cash and cash equivalents, beginning of period	77,735,300	80,379,300
Cash and cash equivalents, end of period	$94,629,100	$55,640,100

See accompanying notes to unaudited condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
March 31, 2005
(Unaudited)

1. Accounting Policies

Reference is hereby made to Petroleum Development Corporation and Subsidiaries' (the Company) Annual Report on Form 10-K for 2004, which contains a summary of significant accounting policies followed by the Company in the preparation of its consolidated financial statements. These policies were also followed in preparing the quarterly report included herein.

2. Stock Compensation

The Company applies the intrinsic-value based method of accounting prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations including FASB Interpretation No. 44, "Accounting for Certain Transactions involving Stock Compensation, an interpretation of APB Opinion No. 25", to account for its fixed-plan stock options. Under this method, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. FASB Statement No. 123, "Accounting for Stock-Based Compensation" and FASB Statement No. 148, "Accounting for Stock Based Compensation- Transition and Disclosure, an amendment of FASB Statement No. 123", established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. As permitted by existing accounting standards, the Company has elected to continue to apply the intrinsic-value-based method of accounting described above, and has adopted only the disclosure requirements of Statement 123, as amended. If the fair-value-based method had been applied to all outstanding and unvested awards in each period, the impact in 2005 would have been $92,400. There would have been no impact on reported net income in 2004.

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
Net income, as reported	$13,337,800	$8,439,400
Deduct total stock-based employee compensation expense determined under fair-value-based method for all awards, net of tax	(92,400)	-
Pro forma net income	$13,245,400	$8,439,400
Basic earnings per share as reported	$.80	$ .53
Pro forma basic earnings per share	$.80	$ .53
Diluted earnings per share as reported	$.80	$ .52
Pro forma diluted earnings per share	$.80	$ .52

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), "Share-Based Payment" which is a revision of FASB Statement No. 123, "Accounting for Stock-Based Compensation". Statement 123R supersedes APB opinion No. 25, "Accounting for Stock Issued to Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. On April 14, 2005, the SEC amended the effective date of the provisions of this statement. The effect of this amendment by the SEC is that we will have to comply with Statement 123R and use the Fair Value based method of accounting no later than the first quarter of 2006. Management has not determined the impact that this statement will have on our consolidated financial statements.

3. Basis of Presentation

The Management of the Company believes that all adjustments (consisting of only normal recurring accruals) necessary to a fair statement of the results of such periods have been made. The results of operations for the three months ended March 31, 2005 are not necessarily indicative of the results to be expected for the full year.

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, 2005 and 2004:

	2005	2004
Weighted average common shares outstanding	16,589,824	15,861,897
Weighted average common and common equivalent shares outstanding	16,642,888	16,304,526
Net income	$13,337,800	$8,439,400
Basic earnings per common share	$0.80	$0.53
Diluted earnings per share	$0.80	$0.52

6. Business Segments

PDC's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations and pipeline income. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 2,700 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, 2005 and 2004 is as follows: (All amounts presented below are in thousands.)

	2005	2004
REVENUES		
Drilling and Development	$32,351	$29,500
Natural Gas Marketing	24,362	23,457
Oil and Gas Sales	18,463	16,196
Well Operations and Pipeline Income	2,113	1,838
Unallocated amounts (1)	6,153	58
Total	$83,442	$71,049

SEGMENT INCOME BEFORE INCOME TAXES		
Drilling and Development	$ 4,722	$ 4,144
Natural Gas Marketing	368	601
Oil and Gas Sales	10,509	8,802
Well Operations and Pipeline Income	1,230	920
Unallocated amounts (2)		
General and Administrative expenses	(1,618)	(994)
Interest expense	(44)	(244)
Other (1)	6,004	(42)
Total	$21,171	$13,187

	March 31, 2005	December 31, 2004
SEGMENT ASSETS		
Drilling and Development	$ 65,239	$ 64,348
Natural Gas Marketing	24,524	28,689
Oil & Gas Sales	252,432	221,516
Well Operations and Pipeline Income	18,996	16,518
Unallocated amounts		
Cash	33	112
Other	6,851	10,210
Total	$368,075	$341,393

(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 which are not allocated in assessing segment performance.

(2) Items which are not allocated in assessing segment performance.

7. Sale of Undeveloped Acreage

On January 28, 2005 the Company sold a portion of one of its undeveloped Garfield County, Colorado leases to an unaffiliated entity. The proceeds of the sale were $6.2 million and the Company's carrying value of the property was zero. The Company is required to remit $1.0 million to the original lessor, unless it constructs certain facilities adjacent to this undeveloped property subject to certain timing conditions. The Company at this time cannot determine if it will be able to comply with this provision, therefore a $1.0 million accrual has been established and the pre-tax gain on the sale was reduced to $5.2 million. This gain has been included in "Other Income" in the accompanying income statement and amounted to an after-tax effect on Earnings Per Share of $.20.

8. Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to shareholders' equity and classified as Other Comprehensive Income. The following table illustrates the calculation of comprehensive income for the three months ended March 31, 2005 and 2004.

	2005	2004
Net income	$13,337,800	$8,439,400
Other Comprehensive Income (loss) (net of tax):		
Reclassification adjustment for settled contracts included in net income (net of tax of $744,500 and $134,400, respectively)	1,169,400	211,100
Change in fair value of outstanding hedging positions (net of tax of $3,488,200 and $900,000, respectively)	(5,478,900)	(1,413,700)
Other Comprehensive Income (loss)	(4,309,500)	(1,202,600)
Comprehensive Income	$ 9,028,300	$ 7,236,800

9. 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 sales to a few customers. The Company sells natural gas to various public utilities, natural gas marketers, industrial and commercial customers.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's hedging 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 the first quarter of 2005 or the year 2004.

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 $7.5 million. The Company believes it has adequate liquidity to meet this obligation.

The Company's drilling programs formed since 1996 contain a performance standard which states that if certain performance levels are not met, the Company must remit a payment equal to one-half of its share of revenue from such partnership to the investing partners. For the three months ended March 31, 2005 and 2004, the Company paid partnerships a total of $124,200 and $97,200 respectively in accordance with the provision.

As Managing General Partner of 10 private limited partnerships and 64 public limited partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company is generally the sole general partner of each of these various limited partnerships. The Company believes its casualty insurance coverage is adequate to meet this potential liability.

In order to secure the services for drilling rigs, the Company makes commitments to the drilling contractor which call for penalties for a specified amount of time if the Company ceases to use such drilling rigs, an event that is not anticipated to occur. As of March 31, 2005, the Company has an outstanding commitment for $672,750.

The Company drilled one exploratory well in 2004 (Fox Federal #1-13) and drilled another one in the first quarter of 2005 (Coffeepot Springs #24-34). The Fox Federal #1-13 has been completed and testing was underway, however, the well has not been classified as successful or dry. Testing of this well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing late in the second quarter of 2005. The cost of this well as of April 30, 2005 is $4.5 million. The Coffeepot Springs #24-34 has been drilled to total depth and is scheduled to be fractured in the next few weeks and has not been classified as successful or dry. The cost of this well as of April 30, 2005 is $2.6 million. If either of these wells is determined to be a dry hole, its cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting.

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 affect on the Company's business, financial condition, results of operations, or liquidity.

10. Subsequent Event

On April 27, 2005, the Company completed the sale to an unaffiliated entity of 111 Pennsylvania wells it purchased from Pemco Gas, Inc. in 1998. The Company received proceeds of $3.4 million and will record a gain of approximately $1.1 million in the second quarter of 2005. The transaction was effective April 1, 2005.

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

The Company has recorded historically strong revenues, income and cash flow for the first quarter of 2005. High oil and natural gas prices in combination with record Company production have been the largest contributors to both income and cash flow. The high energy prices have also increased the Company's revenues both for sales of Company-owned production and for gas purchased and sold by Riley Natural Gas, our natural gas marketing subsidiary. Management also believes that high energy prices have increased the attractiveness of its partnership investment programs to investors resulting in a significant increase in the sale of program interests and as a result increased drilling activity, revenues and profits for the Drilling and Development segment. The new wells drilled for the partnerships also led to an increase in revenues for operating wells for the partnerships and others.

The increased level of activities also increased the costs associated with the drilling and development and well operations activities since more goods, services and other costs were incurred as a result of the higher levels of activities. Similarly higher oil and natural gas prices also increased the cost of purchasing gas for resale in the Company's gas marketing unit.

The increased profitability and cash flow from operations allowed the company to reduce its long term debt and to continue to invest in capital projects. The majority of the capital investment was for oil and gas drilling and development activities.

A more detailed explanation of the various components for the most recent quarter follows:

Results of Operations

Three Months Ended March 31, 2005 Compared with March 31, 2004

Revenues

Total revenues for the three months ended March 31, 2005 were $83.4 million compared to $71.0 million for the three months ended March 31, 2004, an increase of approximately $12.4 million or 17.5 percent. Such increase was a result of increased drilling revenues, gas sales from marketing activities, oil and gas sales and well operations and pipeline income and other income.

Drilling Revenues

Drilling revenues for the three months ended March 31, 2005 were $32.4 million compared to $29.5 million for the three months ended March 31, 2004, an increase of approximately $2.9 million or 9.8 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The Company started the first quarter of 2005 with advances for future drilling from December 31, 2004 of $42.5 million. The Company funded its first drilling partnership of the year in the first quarter with $40 million in subscriptions and commenced drilling of the partnership wells late in the first quarter. We believe in part that this increase in drilling program partnership subscriptions is fueled by the increase in oil and natural gas prices which has improved the performance of our prior programs which in turn has helped to increase our current drilling program sales.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's gas marketing subsidiary for the three months ended March 31, 2005 were $24.3 million compared to $23.5 million for the three months ended March 31, 2004, an increase of approximately $800,000 or 3.4 percent. Such increase was due to slightly higher volumes of natural gas sold and higher average sales prices.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended March 31, 2005 were $18.5 million compared to $16.2 million for the three months ended March 31, 2004 an increase of $2.3 million or 14.2 percent. The increase was due to increased volumes sold at higher average sales prices of oil and natural gas. The volume of natural gas sold for the three months ended March 31, 2005 was 2.7 million Mcf at an average sales price of $5.27 per Mcf compared to 2.6 million Mcf at an average sales price of $4.91 per Mcf for the three months ended March 31, 2004. Oil sales were 100,900 barrels at an average sales price of $42.27 per barrel for the three months ended March 31, 2005 compared to 104,000 barrels at an average sales price of $31.84 per barrel for the three months ended March 31, 2004. The increase in 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 NECO, Colorado area of operation, and the investment in oil and gas properties we own in our public drilling program partnerships.

Oil and Gas Production

The Company's oil and natural gas production by area of operations along with average sales price is presented below:

	Three Months Ended March 31, 2005			Three Months Ended March 31, 2004		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	1,099	451,052	457,646	1,204	457,218	464,442
Michigan Basin	982	412,548	418,440	1,151	443,962	450,868
Rocky Mountains	98,815	1,832,635	2,425,525	101,781	1,721,812	2,332,498
Total	100,896	2,696,235	3,301,611	104,136	2,622,992	3,247,808
Average Price	$42.27	$5.27	$5.59	$31.84	$4.91	$4.99

* 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 Colorado continue to trail prices which we receive for our Appalachian and Michigan gas which are based upon NYMEX. The Company's management believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. In 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 Hedging Activities

Because of uncertainty surrounding natural gas prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2006 we have in place a series of floors and ceilings on part of our natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. During the three months ended March 31, 2005 the Company averaged natural gas volumes sold of 899,000 Mcf per month and oil sales of 33,600 barrels per month. The current positions in effect on the Company's share of production are shown in the following table.

		Floors		Ceilings	
Month Set	Month	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
	NYMEX Based Hedges - (Appalachian and Michigan Basins)				
2/04	Apr 2005 – Oct 2005	122,000	$4.28	61,000	$5.00
3/05	Apr 2005 – Oct 2005	39,000	$5.75	19,500	$8.37
1/05	Nov 2005 – Mar 2006	156,000	$5.00	78,000	$8.50
3/05	Apr 2006 –Oct 2006	78,000	$5.50	39,000	$7.40
	Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)				
2/04	Apr 2005- Oct 2005	33,000	$3.10	16,000	$4.43
3/05	Apr 2005 – Oct 2005	38,000	$4.75	19,000	$8.12
1/05	Nov 2005 – Mar 2006	60,000	$4.50	30,000	$7.15
3/05	Apr 2006 – Oct 2006	42,000	$4.50	21,000	$7.25
	NYMEX Based Hedges (NECO Area)				
2/04	Apr 2005 – Oct 2005	150,000	$4.26	75,000	$5.00
1/05	Nov 2005 – Mar 2006	150,000	$5.00	75,000	$8.45
4/05	Apr 2006 – Oct 2006	150,000	$5.00	75,000	$8.62
	Oil - NYMEX Based				
		Bbls		Bbls	
8/04	Apr 2005 – Dec 2005	15,000	$32.30	7,500	$40.00

Well Operations, Pipeline and Other Income

Well operations and pipeline income for the three months ended March 31, 2005 was $2.1 million compared to $1.8 million for the three months ended March 31, 2004, an increase of approximately $300,000 or 16.7 percent. Such 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 for the three months ended March 31, 2005 was $6.2 million compared to $58,000 for the three months ended March 31, 2004, an increase of $6.1 million. The increase is a result of a sale of a portion of one of our undeveloped leases in Garfield County, Colorado, which we sold in January 2005 for a pre-tax profit of $5.2 million, along with management fees collected from the funding of our 2005-A drilling partnership and interest earned on higher average cash balances.

Costs and Expenses

Costs and expenses for the three months ended March 31, 2005 were $62.3 million compared to $57.9 million for the three months ended March 31, 2004, an increase of approximately $4.4 million or 7.6 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, and general and administrative expenses.

Oil and Gas Well Drilling Operations Costs

Oil and gas well drilling operations costs for the three months ended March 31, 2005 were $27.6 million compared to $25.4 million for the three months ended March 31, 2004, an increase of approximately $2.2 million or 8.7 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above. The gross margin on the drilling activities for the three months ended March 31, 2005 was 14.6% compared with 14.1% for the three months ended March 31, 2004, an increase in gross margin of .5%. For the first two partnerships in 2005, the Company has raised its footage-based drilling rates it charges to its Public Drilling Partnerships to correspond with the rising well fracturing and steel costs for casing and other well equipment.

Cost of Gas Marketing Activities

The costs of gas marketing activities for the three months ended March 31, 2005 were $24.0 million compared to $22.9 million for the three months ended March 31, 2004, an increase of $1.1 million or 4.8 percent. Such increase was due to slightly higher volumes of natural gas purchased for resale, at higher average purchase prices. Income before income taxes for the Company's natural gas marketing subsidiary decreased from $601,000 for the three months ended March 31, 2004 to $368,000 for the three months ended March 31, 2005. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production Costs

Oil and gas production costs from the Company's producing properties for the three months ended March 31, 2005 were $4.2 million compared to $3.9 million for the three months ended March 31, 2004, an increase of approximately $300,000 or 7.7 percent. Such increase was due to increased production costs and severance and property taxes on the increased volumes and higher sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting cost per Mcfe increased from $.98 to $1.09 per Mcfe due to increased severance and property taxes on the significantly increased oil and gas prices along with additional well workovers and production enhancements work performed.

General and Administrative Expenses

General and administrative expenses for the three months ended March 31, 2005 were $1,617,000, compared to $994,000 for the three months March 31, 2004, an increase of approximately $623,000, or 62.7 percent. The increase was due to the costs of complying with the various provisions of Sarbanes Oxley, in particular with Section 404 (Internal Controls), which amounted to $550, 000 for the three months ended March 31, 2005.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended March 31, 2005 increased to $4.8 million from approximately $4.5 million for the three months ended March 31, 2004, an increase of approximately $300,000 or 6.7 percent. Such increase was due to the increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest cost for the three months ended March 31, 2005 was $44,000 compared to $244,000 for the three months ended March 31, 2004, a decrease of $200,000 or 82.0 percent. Such decrease was due to significantly lower average outstanding balances of our credit facility offset in part by higher interest rates. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest. The average outstanding debt balance for the three months ended March 31, 2005 was $867,000 compared to $12.1 million for the three months ended March 31, 2004.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 36 percent to 37 percent primarily because of miscellaneous permanent differences in 2004 which are not expected in 2005, offset in part by additional benefit to be realized for the tax deduction for domestic production activities.

Net income and Earnings

Net income for the three months ended March 31, 2005 was $13.3 million compared to a net income of $8.4 million for the three months ended March 31, 2004, an increase of approximately $4.9 million or 58.3 percent.

Diluted earnings per share for the three months ended March 31, 2005 was $.80 per share compared to $0.52 per share for the three months ended March 31, 2004, an increase of $.28 per share or 53.8 percent.

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. Operational 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 for the Company's public 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 payments exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities.

Oil and Gas Hedging Activities

Because of the uncertainty surrounding natural gas and oil prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2006 we have in place a series of floors and ceilings on part of our natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. See previous pages in this Management's Discussion and Analysis for a schedule of hedging positions.

The Company hedges 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.

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 quarter prices for natural gas were close to or above record levels, and future expectations as reflected in the NYMEX futures market are for continuing high price levels for the balance of 2005 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 tend to be fairly closely related after allowing for differences in the quality and energy content of the gas, the location and distance to market, and other factors. Sometimes prices in a particular area may vary from historical relationships. This can 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. However 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 the first quarter. 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.

Public Drilling Programs

During January, 2005, the Company commenced sales and funded its first 2005 Partnership (PDC 2005-A) at its maximum subscriptions of $40 million, the largest PDC partnership to date. The Company commenced the drilling operations of the partnership late in the first quarter and will continue to drill for the partnership into the second and third quarter of 2005.

In April, 2005, the Company commenced sales and funded its second 2005 Partnership at its maximum allowable subscriptions of $40 million. The Company plans to commence drilling operations of this partnership late in the second quarter and continue to drill for the partnership during the third and fourth quarters of 2005.

The third and final partnership of 2005 is scheduled to close later in the year with maximum subscriptions of $35 million. If the Company sells $35 million in the third 2005 partnership, the total subscriptions in 2005 will be $115 million compared to $100 million for 2004. The Company invests, as its equity contribution to each drilling partnership, an additional sum of 22% of the aggregate investor 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.

Substantially all of the Company's drilling programs contain a repurchase provision allowing Investors to request that the Company repurchase their partnership units at any time beginning with the third anniversary after 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), only if investors request the Company to repurchase such 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 $7.5 million. The Company has adequate liquidity to meet this obligation. During the first three months of 2005, the Company purchased $59,300 under this provision.

The Company posts daily the amount of subscriptions that have been sold in the current partnership at its website, www.petd.com under the heading of “Drilling Program”.

Drilling Activity

During the first three months 2005, the Company drilled along with its public drilling fund partnerships a total of 38 successful wells. The Company drilled 29 successful wells in its Wattenberg field in the Denver-Julesburg Basin and nine successful wells in the Piceance Basin in western Colorado, all of the wells that the Company drills in these two areas are in conjunction with its public drilling fund partnerships. The Company plans to conduct the remainder of its 2005 partnership drilling activity in these two areas.

In the first quarter of 2005, the Company also drilled for its own account a four-well program on its northeast Colorado properties (NECO). The wells are being drilled on locations created by the regulatory approval of the reduction in well spacing from 80 to 40 acres on the properties the Company acquired in Yuma County in 2003.

The Company drilled one exploratory well in 2004 (Fox Federal #1-13) and drilled another one in the first quarter of 2005 (Coffeepot Springs #24-34). The Fox Federal #1-13 has been completed and testing was underway but the well has not been classified as successful or dry. Testing of this well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing late in the second quarter of 2005. The cost of this well as of April 30, 2005 is $4.5 million. The Coffeepot Springs #24-34 has been drilled to total depth and is scheduled to be fractured in the next few weeks and has not been classified as successful or dry. The cost of this well as of April 30, 2005 is $2.6 million. If either of these wells is determined to be a dry hole, its cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting. Currently the Company plans to retain most if not all of the working interest in the exploratory wells, since the Company partnerships focus on developmental activities and are allowed only limited participation in exploratory drilling.

Purchase of Oil and Gas Properties

Although the Company made several offers to purchase producing oil and gas properties from other companies during the first three months of 2005, it was not successful in purchasing any of those properties. The Company did purchase a number of small interests in its partnerships from investors wishing to liquidate their holdings under the repurchase provision of the partnerships.

Costs incurred by the Company in oil and gas acquisitions, exploration and development for the three months ended March 31, 2005 are presented below:

Property acquisition cost:	
Proved undeveloped properties	$3,776,700
Producing properties	72,600
Development costs	15,673,800
	$19,523,100

Common Stock Repurchase Program

At a meeting held on Friday, March 18, 2005, the Board of Directors of Petroleum Development Corporation approved a stock repurchase plan to allow the Company to repurchase up to 2% of the Company's common stock in 2005. The Company intends at a minimum to purchase adequate shares to insure no dilution from employee stock compensation plans and may also make open market purchases from time to time.

Working Capital

Although the Working Capital of the Company as of March 31, 2005 is a negative $7.9 million this amount included a liability of $9.2 million related to the fair value of derivatives. Such amount may or may not be realized depending on the change in the fair value of derivatives upon settlement.

Long-Term Debt

The Company has a credit facility with Chase Bank NA and BNP Paribas of $100 million subject to and secured by adequate levels of oil and gas reserves. The current total borrowing base is $80.0 million of which the Company has activated $60 million of the facility. The Company is required to pay a commitment fee of 1/4 percent 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 July 3, 2008.

As of March 31, 2005, the outstanding balance was $18,000,000. 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 certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. As of March 31, 2005, the Company was in compliance with all financial covenants in the credit agreement. At March 31, 2005, the outstanding balance was subject to a prime rate of 5.75%.

Contractual Obligations

Contractual obligations and due dates are as follows:

	Payments due by period				
		Less than	1-3	3-5	More than
Contractual Obligations	Total	1 year	years	years	5 years
Long-Term Debt	$18,000,000	$ 0	$ 0	$18,000,000	$ 0
Operating Leases	816,700	299,700	331,200	139,800	46,000
Asset Retirement Obligation	794,600	50,000	50,000	50,000	644,600
Drilling Rig Commitment	672,750	672,750	0	0	0
Other Liabilities	5,111,700	40,000	2,264,600	250,000	2,557,100
Total	$25,395,750	$1,062,450	$2,645,800	$18,439,800	$3,247,700

Long-term debt in the above table does not include interest as 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. Management believes that the Company has adequate capital to meet its operating requirements.

Commitments and Contingencies

As Managing General Partner of 10 private limited partnerships and 64 public limited partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company is generally the sole general partner of each of these various limited partnerships. The Company believes its casualty insurance coverage is adequate to meet this potential liability.

Factors That May Affect Future Results and Financial Conditions

In the course of its normal business the Company is subject to a number of risks that could potentially adversely impact its revenues, expenses and financial condition. The following is a discussion of some of the more significant risks.

Drilling of oil and natural gas wells is highly speculative and may be unprofitable or result in the loss of the entire investment in a well and the lease on which it is located. To the extent the Company drills unsuccessful developmental wells its future profitability will be reduced on production from the field where the well is located, since the investment in the well will be included in the investment in the field and depreciated on the unit-of-production method. Recently the Company has begun drilling several planned exploratory wells that could lead to significant future development opportunities. Under the Successful Efforts method used by the Company, the costs of exploratory dry holes are taken as an expense in the period when it is determined that they are non-productive. As a result exploratory dry holes, if any are drilled, will result in an immediate reduction in net income for that period.

Reductions in prices of oil and natural gas reduce the profitability of the Company's production operations. Revenue from the sale of oil and gas increases when prices increase and declines when prices decrease. These price changes can occur rapidly and are not predictable nor within the control of the Company.

Changes in prices of oil and natural gas may also affect sales of drilling programs. Recent energy price increases have coincided with increased sales of the Company's partnership investments, and increased profitability from those operations. It is likely that declining prices could have the opposite effect, reducing partnership sales and profitability. Because the Company has not been able to meet the demand for oil and gas investments from its Broker/Dealer network, those Broker/Dealers have been seeking investments from other oil and gas program sponsors. These new competitors could potentially take business from the Company, particularly in a declining price market for oil and gas.

Increases in prices of oil and natural gas have increased the cost of drilling, the cost of potential acquisitions and other factors affecting the performance of the Company in both the short and long term. In the current high price environment most oil and gas companies have increased their expenditures for drilling new wells. This has resulted in increased demand and higher prices for leases, oilfield services and well equipment. Similarly higher energy prices have increased the price purchasers are willing to pay for producing properties and increased competition for the properties that are available. These factors make it more difficult to add to the Company's production, and increase the cost of additions. To the extent that new reserves and production are added at these higher prices in addition to the increased drilling costs, the risk to the Company of decreased profitability from future decreases in oil and gas prices is increased.

The Company's hedging activities could result in reduced revenue compared to the level the Company would experience if no hedges were in place. The Company uses hedges to reduce the impact of price movements on revenue. While these hedges protect the Company against the impact of declining prices, they also may limit the positive impact of price increases. As a result the Company may have lower revenues when prices are increasing than might otherwise be the case.

The high level of drilling activity could result in an oversupply of natural gas on a regional or national level resulting in much lower commodity prices. Recently the natural gas market been characterized by excess demand compared to the supplies available. The high level of drilling, combined with reduction in demand resulting from high prices could result in an oversupply of natural gas. On a local level increasing supplies could exceed available pipeline capacity. In both cases the result would probably be lower prices for the natural gas the Company produces and reduced profitability for the Company.

The Company owns interests in and operates more than 2,700 wells and drills many new wells each year. Environmental hazards and unpredictable costs associated with those wells could have a negative impact on the performance of the Company. While many of the wells the Company drills are relatively low risk development wells, the Company also plans to drill exploratory wells to test new areas in coming months. Under the terms of the Company's drilling agreements with its partnerships the Company also bears the risk for the investor partners interests in new wells through an indemnification agreement. The costs associated with problems encountered in drilling, completing and operating wells can be significant, and could adversely affect the profitability of the Company if such problems are encountered.

Changes in the Tax Code could reduce the attractiveness of the Company's partnership investments and reduce the revenues and profitability of those operations. The partnership interests sold by the Company offer investors significant tax benefits under current tax regulations. If the Congress changes the Code and eliminates or reduces those benefits investments in the partnerships would be less attractive to investors and fewer investors might invest.

Increasing interest rates could increase the cost of the Company's borrowing. Higher interest rates would increase the interest costs of the Company's borrowing, and would make additional borrowing less attractive. This could also make potential acquisitions and other activities funded with borrowed money less profitable, potentially reducing the rate of growth of production and reserves. Consequently, the Company's profitability could be reduced.

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 listing 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 observance 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 account policies" in our financial statements and related notes on Form 10-K. Our critical accounting policies and estimates are as follows:

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our publicly registered drilling programs using the percentage of completion method. These contracts are footage rate based and 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. The percentage of completion method measures 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 continually during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts would be recorded at the time that our estimated costs exceeded the contract revenue. The Company has not experienced any contract losses in 2005 or 2004.

Natural gas marketing is recorded on the gross accounting method. Riley Natural Gas ("Riley"), 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. Riley 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 Riley takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership.

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 is competitive with rates charged by other operators in the area. 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 that are not designated as accounting hedges are recorded in earnings.

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. In addition, for hedges of forecasted transactions, the Company must estimate the expected future cash flows of the forecasted transactions, as well as evaluate the probability of the occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could affect the timing of recognition in earnings for changes in fair value of certain hedging derivatives.

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 the impairment test, the Company estimates the future cash flows associated with individual assets or groups of assets. Impairment must be 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

Exploration and development costs are accounted for by the successful efforts method.

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 expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. 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.

Property acquisition costs are capitalized when incurred. Geological and geophysical costs and delay rentals are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered economically producible reserves. If reserves are not discovered, such costs are expensed as dry holes. Development costs, including equipment and intangible drilling costs related to both producing wells and developmental dry holes, are capitalized.

Unproved properties or leases are written-off to expense when it is determined that they will expire or be abandoned.

Costs of proved properties, including leasehold acquisition, exploration and development costs and equipment, are depreciated or depleted by the unit-of-production method based on estimated proved developed oil and gas reserves.

Upon sale or retirement of 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 a partial unit of property, the proceeds are credited to accumulated depreciation and depletion.

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 cannot be recognized under the preceding criteria, a valuation allowance has been 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.

New Accounting Standards

The FASB issued FIN 46, "Consolidation of Variable Interest Entities", in January 2003 and amended the interpretation in December 2003. A variable interest entity (VIE) is an entity in which its voting equity investors lack the characteristics of having a controlling financial interest or where the existing capital at risk is insufficient to permit the entity to finance its activities without receiving additional financial support from other parties. FIN 46 requires the consolidation of entities which are determined to be VIEs when the reporting company determines itself to be the primary beneficiary (the entity that will absorb a majority of the VIE's expected losses, receive a majority of the VIE's residual returns, or both). The amended interpretation was effective for the first interim or annual reporting period ending after March 15, 2004, with the exception of special purpose entities for which the statement was effective for periods ending after December 15, 2003. We have completed a review of our partnership investments and have determined that those entities do not qualify as VIEs.

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), "Share-Based Payment" which is a revision of FASB Statement No. 123, "Accounting for Stock-Based Compensation". Statement 123R supersedes APB opinion No. 25, "Accounting for Stock Issued to Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The provisions of this statement becomes effective for our first quarter 2006. Management has not determined the impact that this statement will have on our consolidated financial statements.

Recently Issued Accounting Pronouncements

Asset Retirement Obligations

On March 30, 2005, the FASB issued FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN No. 47). This interpretation clarifies that the term “conditional asset retirement obligation” as used in Statement No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity incurring the obligation. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability, rather than the timing of recognition of the liability, when sufficient information exists. FIN No. 47 will be effective for the Company at the end of the fiscal year ended December 31, 2005. The Company has not determined the impact on the Company’s financial position or results of operations of the application of FIN No. 47.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1 “Accounting for Suspended Well Costs.” This staff position amends FASB Statement No. 19 “Financial Accounting and Reporting by Oil and Gas Producing Companies” and provides guidance about exploratory well costs to companies which use the successful efforts method of accounting. The position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well’s economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management’s evaluation of capitalized exploratory well costs. In addition, the FSP requires annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. The guidance in the FSP is required to be applied to the first reporting period beginning after April 4, 2005 on a prospective basis to existing and newly capitalized exploratory well costs. The Company does not expect the application of this FSP to have a significant impact on the Company’s financial position or results of operations.

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 prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, 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.

When used in the Form 10-Q, the words, "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussions and Analysis of Financial Condition and Results of Operations" and elsewhere in this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosure About Market Rate Risk

Interest Rate Risk

There have been no material changes in the reported market risks faced by the Company since December 31, 2004.

Commodity Price Risk

The Company utilizes commodity-based derivative instruments as hedges 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 and CIG-based contracts traded by JP Morgan for Colorado production. These hedging arrangements 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 hedge relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these hedging arrangements are structured to reduce the Company's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the hedged commodity. 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 futures and options contracts for Riley Natural Gas and PDC as of March 31, 2005 and 2004.

Riley Natural Gas
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of March 31, 2005					
Natural Gas	Sale	3,947,000	$6.10	$24,072,530	($6,875,781)
Natural Gas	Purchase	710,000	$6.48	$4,602,990	$1,007,870
Natural Gas	Sale Option	320,000	$5.42		$6,492
Natural Gas	Purchase Option	160,000	$7.06		($150,218)

Contracts maturing in 12 months following March 31, 2005					
Natural Gas	Sale	2,947,000	$6.36	$18,734,450	($4,889,375)
Natural Gas	Purchase	610,000	$6.62	$4,037,140	$846,990
Natural Gas	Sale Option	320,000	$5.42		$6,492
Natural Gas	Purchase Option	160,000	$7.06		($150,218)
Prior Year Total Contracts as of March 31, 2004					
Natural Gas	Sale	3,380,000	$4.77	$16,115,800	($3,286,000)
Natural Gas	Purchase	580,000	$4.90	$2,402,300	$397,400
Natural Gas	Sale Option	360,000	$4.75		$0
Natural Gas	Purchase Option	180,000	$6.74		$0

The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 27 months.

Petroleum Development Corporation
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of March 31, 2005					
Natural Gas	Sale				
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)
Contracts maturing in 12 months following March 31, 2005					
Natural Gas	Sale				
Natural Gas	Purchase	35,100	$6.58	$230,802	$46,554
Natural Gas	Sale Option	4,996,176	$4.68		$141,062
Natural Gas	Purchase Option	2,498,088	$6.74		($4,116,699)
Crude Oil	Sale Option	118,341	$32.30		$3,818
Crude Oil	Purchase Option	59,171	$40.00		($981,930)
Prior Year Total Contracts as of March 31, 2004					
Natural Gas	Sale				
Natural Gas	Purchase	34,400	$4.69	$160,700	$44,500
Natural Gas	Sale Option	4,643,900	$4.24		$0
Natural Gas	Purchase Option	1,681,000	$5.11		($529,500)
Crude Oil	Sale Option	88,600	$31.63		($236,600)
Crude Oil	Purchase Option				

The maximum term over which PDC is hedging exposure to the variability of cash flows for commodity price risk is 19 months.

See “Working Capital” in Management’s Discussions of Liquidity and Capital Resources for the effect of these contracts on the Company’s Consolidated Balance Sheet.

The average NYMEX closing price for natural gas for the first quarter of 2005 and the year 2004 was $6.27 and $6.14 Mmbtu. The average NYMEX closing price for oil for the first quarter of 2005 and the year 2004 was $47.90 and $41.44 bbl. 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

Under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, the Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Exchange Act Rule 13a-14(c)) as of the end of this fiscal quarter, and, based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective in all material respects, including those to ensure that information required to be disclosed in reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in the Commission's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely disclosure. There have been no significant changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect these controls that occurred during the Company's last fiscal quarter covered by this report and subsequent to the date of their evaluation.

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. Unregistered Sales of Equity Securities and Use of Proceeds

None.

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

None.

Item 6. Exhibits

Exhibit Name	Exhibit Number	Location
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.
Section 1350 Certification by Chief Executive Officer and Chief Financial Officer	32.1	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: May 6, 2005

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

Date: May 6, 2005

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