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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 June 30, 2004

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: 16,268,294 shares of the Company's Common Stock ($.01 par value) were outstanding as of June 30, 2004.

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

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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 June 30, 2004, the related condensed consolidated statements of income for the three-month and six-month periods ended June 30, 2004 and 2003, and the related condensed consolidated statements of cash flows for the six-month periods ended June 30, 2004 and 2003. 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.

KPMG LLP

Pittsburgh, Pennsylvania
July 30, 2004

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets
June 30, 2004 and December 31, 2003

ASSETS

	2004 (Unaudited)	2003
Current assets:		
Cash and cash equivalents	$48,857,200	80,379,300
Accounts and notes receivable	31,360,300	22,523,600
Inventories	4,058,700	2,557,700
Prepaid expenses	8,002,400	5,907,000
Total current assets	92,278,600	111,367,600
Properties and equipment	275,485,200	265,864,300
Less accumulated depreciation, depletion, and amortization	80,194,000	71,182,100
	195,291,200	194,682,200
Other assets	751,800	672,200
	$288,321,600	306,722,000

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued
June 30, 2004 and December 31, 2003

LIABILITIES AND STOCKHOLDERS' EQUITY

	2004 (Unaudited)	2003
Current liabilities:		
Accounts payable and accrued expenses	$51,904,800	46,267,200
Advances for future drilling contracts	23,444,300	50,458,800
Funds held for future distribution	12,662,200	8,410,900
Total current liabilities	88,011,300	105,136,900
Long-term debt	30,000,000	53,000,000
Other liabilities	2,874,800	2,449,100
Deferred income taxes	25,963,100	21,800,200
Asset retirement obligations	749,200	731,200
Stockholders' equity:		
Common stock par value $0.01 per share; authorized 50,000,000 shares; issued and outstanding 16,268,294 shares and 15,638,733 shares	162,700	156,200
Additional paid-in capital	30,940,900	28,578,100
Retained earnings	113,101,700	96,049,200
Accumulated other comprehensive income, net	(3,482,100)	(1,178,900)
Total stockholders' equity	140,723,200	123,604,600
	$288,321,600	306,722,000

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Income
Three Months and Six Months ended June 30, 2004 and 2003
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Revenues:				
Oil and gas well drilling operations	$29,453,800	$11,866,400	$58,953,100	$33,363,900
Gas sales from marketing activities	26,011,400	17,353,200	49,468,800	38,958,300
Oil and gas sales	15,859,200	10,919,200	32,055,400	19,778,000
Well operations and pipeline income	1,912,400	1,768,600	3,749,900	3,416,900
Other income	687,000	285,100	745,100	669,800
	73,923,800	42,192,500	144,972,300	96,186,900
Costs and expenses:				
Cost of oil and gas well drilling operations	24,967,300	10,120,000	50,323,000	27,795,800
Cost of gas marketing activities	25,648,900	17,112,200	48,503,600	38,459,600
Oil and gas production costs	4,036,000	3,460,400	7,942,100	6,317,400
General and administrative expenses	900,900	1,186,600	1,895,100	2,364,300
Depreciation, depletion, and amortization	4,663,300	3,143,600	9,171,000	6,389,200
Interest	255,000	259,800	498,500	496,000
	60,471,400	35,282,600	118,333,300	81,822,300
Income before income taxes and cumulative effect of change in accounting principle	13,452,400	6,909,900	26,639,000	14,364,600
Income taxes	4,839,300	2,280,300	9,586,500	4,740,300
Net income before cumulative effect of change in accounting principle	8,613,100	4,629,600	17,052,500	9,624,300
Cumulative effect of change in accounting principle (net of income taxes of $121,700)	-	-	-	(198,600)
Net income	$8,613,100	$4,629,600	$ 17,052,500	$ 9,425,700
Basic earnings per common share before accounting change	$0.53	$0.29	$1.06	$0.61
Cumulative effect of change in accounting principle	$ -	$ -	$ -	$(0.01)
Basic earnings per common share	$0.53	$0.29	$1.06	$0.60
Diluted earnings per share before accounting change	$0.52	$0.29	$1.04	$0.60
Cumulative effect of change in accounting principle	$ -	$ -	$ -	$(0.01)
Diluted earnings per share	$0.52	$0.29	$1.04	$0.59

See accompanying notes to condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows
Six Months Ended June 30, 2004 and 2003
(Unaudited)

	2004	2003
Cash flows from operating activities:		
Net income	$17,052,500	$ 9,425,700
Adjustments to net income to reconcile to cash provided by operating activities:		
Deferred federal income taxes	5,629,400	3,196,900
Depreciation, depletion & amortization	9,171,000	6,389,200
Cumulative effect of change in accounting principle	-	198,600
Accretion of asset retirement obligation	18,000	18,000
Loss (gain) from sale of assets	13,200	(116,600)
Leasehold acreage expired or surrendered	171,000	1,289,300
Amortization of stock award	1,800	2,700
Increase in current assets	(9,488,000)	(5,426,800)
(Increase) decrease in other assets	(142,100)	2,094,200
Decrease in current liabilities	(20,744,000)	(19,279,100)
Increase (decrease) in other liabilities	425,700	(1,819,700)
Total adjustments	(14,944,000)	(13,453,300)
Net cash provided by operating activities	2,108,500	(4,027,600)
Cash flows from investing activities:		
Capital expenditures	(10,945,600)	(39,124,800)
Proceeds from sale of leases	992,500	684,800
Proceeds from sale of fixed assets	51,400	125,700
Net cash used in investing activities	(9,901,700)	(38,314,300)
Cash flows from financing activities:		
Net (retirement of)/proceeds from long-term debt	(23,000,000)	23,000,000
Proceeds from issuance of common stock	2,020,200	-
Repurchase and cancellation of treasury stock	(2,749,100)	(606,000)
Net cash (used in) provided by financing activities	(23,728,900)	22,394,000
Net decrease in cash and cash equivalents	(31,522,100)	(19,947,900)
Cash and cash equivalents, beginning of period	80,379,300	51,023,500
Cash and cash equivalents, end of period	$ 48,857,200	$ 31,075,600

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
June 30, 2004
(Unaudited)

1. Accounting Policies

Reference is hereby made to the Company's Annual Report on Form 10-K for 2003, 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 has adopted SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS 123 allows entities to continue to measure compensation cost for stock-based awards using the intrinsic value based method of accounting prescribed by APB Opinion No. 25, "Accounting for Stock Issued to Employees," and to provide pro forma net income and pro forma earnings per share disclosures as if the fair value based method defined in SFAS 123 had been applied. The Company has elected to continue to apply the provisions of APB 25 and provide the pro forma disclosure provisions of SFAS 123. For stock options granted, the option price was not less than the market value of shares on the grant date, therefore, no compensation cost has been recognized. No options were granted during the six months ended June 30, 2004 or June 30, 2003. All options were fully vested prior to January 1, 2003. Had compensation cost been determined under the fair value provisions of SFAS 123, the Company's net income and earnings per share would have been the following on a pro forma basis:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net income, as reported	$8,613,100	4,629,600	17,052,500	9,425,700
Deduct total stock-based employee compensation expense determined Under fair-value-based method For all rewards, net of tax	-	-	-	-
Pro forma net income	$8,613,100	4,629,600	17,052,500	9,425,700
Basic Earnings per share as reported	$0.53	$0.29	$1.06	$0.60
Pro forma basic earnings per share	$0.53	$0.29	$1.06	$0.60
Diluted earnings per share as reported	$0.52	$0.29	$1.04	$0.59
Pro forma diluted earnings per share	$0.52	$0.29	$1.04	$0.59

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 six months ended June 30, 2004 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 basic and diluted earnings per common and common equivalent share are as follows for the three months and six months ended June 30,

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Weighted average common shares outstanding	16,272,763	15,645,743	16,067,330	15,687,020
Weighted average common and common equivalent shares outstanding	16,679,382	16,175,749	16,471,709	16,095,955
Net income before cumulative effect of change In accounting principle	$8,613,100	4,629,600	17,052,500	9,624,300
Cumulative effect of change in accounting principle (net of taxes of $121,700)	-	-	-	(198,600)
Net income	$8,613,100	4,629,600	17,052,500	9,425,700
Basic earnings per common share before accounting change	$0.53	$0.29	$1.06	$0.61
Cumulative effect of change in accounting principle	-	-	-	$(0.01)
Basic earnings per common share	$0.53	$0.29	$1.06	$0.60
Diluted earnings per common share before accounting change	$0.52	$0.29	$1.04	$0.60
Cumulative effect of change in accounting principle	-	-	-	(0.01)
Diluted earnings per common share	$0.52	$0.29	$1.04	$0.59

6. Business Segments (Thousands)

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 over 2,600 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. Segment information for the three and six months ended June 30, 2004 and 2003 is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
REVENUES				
Drilling and Development	$29,454	11,866	58,953	33,364
Natural Gas Marketing	26,011	17,353	49,469	38,958
Oil and Gas Sales	15,859	10,920	32,055	19,778
Well Operations and Pipeline Income	1,912	1,769	3,750	3,417
Unallocated amounts (1)	687	285	745	670
Total	$73,923	42,193	144,972	96,187

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
SEGMENT INCOME BEFORE INCOME TAXES				
Drilling and Development	$4,486	1,746	8,630	5,568
Natural Gas Marketing	360	125	961	245
Oil and Gas Sales	8,217	5,562	17,019	9,449
Well Operations and pipeline income	961	717	1,881	1,451
Unallocated amounts (2)				
General and Administrative expenses	(901)	(1,187)	(1,895)	(2,364)
Interest expense	(255)	(260)	(499)	(496)
Other (1)	584	207	542	512
Total	$ 13,452	6,910	26,639	14,365

	June 30, 2004	December 31, 2003
SEGMENT ASSETS		
Drilling and Development	$39,480	62,546
Natural Gas Marketing	24,493	17,006
Oil and Gas Sales	197,305	204,849
Well Operations and pipeline income	13,927	11,602
Unallocated amounts		
Cash	759	800
Other	12,358	9,919
Total	$ 288,322	306,722

(1) Includes interest on investments and partnership management fees which are not allocated in assessing segment performance.

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

7. 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 six months ended June 30, 2004 and 2003.

	2004	2003
Net Income before cumulative effect of change in accounting principle	$17,052,500	$ 9,624,300
Cumulative effect on prior years of SFAS 143 - "Accounting for Asset Retirement Obligations" (net of taxes of $121,700)	-	(198,600)
Net income	17,052,500	9,425,700
Other Comprehensive Loss (net of tax):		
Reclassification adjustment for settled Contracts included in net income (net of tax of $ 4,100 and $435,000, respectively)	6,400	709,700
Change in fair value of outstanding hedging positions (net of tax of $1,470,400 and $1,123,800, respectively)	(2,309,600)	(1,833,500)
Other Comprehensive Loss	(2,303,200)	(1,123,800)
Comprehensive Income	$14,749,300	$8,301,900

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 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 two quarters of 2004 or the year 2003.

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 months' 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 $5.6 million. The Company has adequate liquidity to meet this obligation.

The Company is not party to any legal action that would materially affect the Company's results of operations or financial condition.

9. Common Stock Repurchase

On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program is scheduled to expire on December 31, 2004. The following activity has occurred since inception of the plan on March 13, 2003 until June 30, 2004.

Month of Purchase	March, 2003	April, 2003	September, 2003
Average Price paid per share	$6.08	$6.48	$11.15
Broker/Dealer	McDonald Investments	McDonald Investments	McDonald Investments
Number of Shares Purchased	46,500	49,900	12,800
Remaining Number of Shares to Purchase	738,500	688,600	675,800

During the quarter ended March 31, 2004 the Compensation Committee of the Board of Directors approved a repurchase of 48,650 shares of common stock from one of the Company's officers. The repurchase price of the common stock was the closing price on the date of the repurchase of $26.61 per share and totaled $1,294,600 which approximated the tax savings to be realized by the Company as a result of the exercise of said officer's non-qualified stock options in the first quarter of 2004. Such treasury stock was subsequently cancelled.

During the quarter ended June 30, 2004 the Company repurchased 50,487 shares from the estate of one of the Company's former officers in accordance with terms of the former officer's employment agreement. The repurchase price of the stock was $27.73 per share (the 90-day average prior to the repurchase per contract). The repurchase totaled $1,400,000 of which $1,000,000 was funded by life insurance proceeds. The life insurance proceeds were recorded as other income in the fourth quarter of 2003. The Company also repurchased 1,703 shares from an employee upon retirement from the Company. Such treasury stock was subsequently cancelled.

10. Change in Accounting Principle

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $198,600 (net of income taxes of $121,700).

11. Acquisition of Oil and Gas Properties

During the second quarter of 2003 the Company completed the purchase of natural gas properties in the Denver-Julesburg Basin in northeastern Colorado for $28 million from Williams Production RMT Company, a subsidiary of The Williams Companies, Inc. of Tulsa, OK. The effective date of the purchase was April 1, 2003. Funding for the acquisition was provided from the Company's bank credit facility with Bank One N.A. and BNP Paribas.

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

Results of Operations

Three Months Ended June 30, 2004 Compared with June 30, 2003

Revenues

Total revenues for the three months ended June 30, 2004 were $73.9 million compared to $42.2 million for the three months ended June 30, 2003, an increase of approximately $31.7 million or 75.1 percent. Such increase was a result of increased drilling revenues, sales from gas marketing activities, oil and gas sales and well operations and pipeline income.

Drilling Revenues

Drilling revenues for the three months ended June 30, 2004 were $29.5 million compared to $11.9 million for the three months ended June 30, 2003, an increase of approximately $17.6 million or 148 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The Company started the second quarter of 2004 with advances for future drilling from March 31, 2004 of $21.0 million compared with advances for future drilling of $15.5 million at the beginning of the second quarter of 2003. During the second quarter of 2004 the Company funded a drilling program with subscriptions of $29.0 million compared to an $8.5 million program funded during the second quarter of 2003. Both programs commenced drilling operations shortly after funding. We believe in part that this increase 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 June 30, 2004 were $26.0 million compared to $17.4 million for the three months ended June 30, 2003, an increase of approximately $8.6 million or 49 percent. Such increase was due to 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 June 30, 2004 were $15.9 million compared to $10.9 million for the three months ended June 30, 2003 an increase of $5.0 million or 46 percent. The increase was due to significantly increased volumes sold at higher average sales prices of oil and natural gas. The volume of natural gas sold for the three months ended June 30, 2004 was 2.5 million Mcf at an average sales price of $5.01 per Mcf compared to 2.1 million Mcf at an average sales price of $4.34 per Mcf for the three months ended June 30, 2003. Oil sales were 96,000 barrels at an average sales price of $32.41 per barrel for the three months ended June 30, 2004 compared to 58,000 barrels at an average sales price of $29.52 per barrel for the three months ended June 30, 2003. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, recompletions of existing wells, two fourth quarter 2003 acquisitions of oil and gas properties in Colorado and Kansas and the investment in oil and gas properties we own in our public drilling program partnerships.

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

	Three Months Ended June 30, 2004			Three Months Ended June 30, 2003		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	1,138	431,040	437,868	1,212	468,884	476,156
Michigan Basin	1,853	425,854	436,972	1,462	447,847	456,619
Rocky Mountains	93,113	1,689,576	2,248,254	55,618	1,201,739	1,535,447
Total	96,104	2,546,470	3,123,094	58,292	2,118,470	2,468,222
Average Price	$32.41	$5.01	$5.08	$29.52	$4.34	$4.42

Our financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas and oil markets has remained prevalent in the last few years and can have a material impact on our financial results. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. The Company 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 78% to 91% for an average of 86% of the NYMEX price, levels consistent with historical price relationships before the local demand/pipeline capacity problem. The Company has commodity price hedging contracts for oil and natural gas production from July 2004 through October 2005 to protect against possible short-term price weaknesses.

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 2005 we have in place a series of floors and ceilings and hedges 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 June 30, 2004 the Company averaged natural gas volumes sold of 849,000 Mcf per month and oil sales of 32,000 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)				
1/04	Jul 2004 - Oct 2004	122,000	$5.00	-	-
10/03	Jul 2004 - Oct 2004	81,000	$4.00	81,000	$5.65
5/04	Nov 2004 - Mar 2005	180,000	$5.67	90,000	$7.00
2/04	Apr 2005 - Oct 2005	122,000	$4.28	61,000	$5.00
		Rocky Mountain Region			
	Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)				
10/03	Jul 2004 - Oct 2004	25,000	$3.20	25,000	$4.70
1/04	Jul 2004 - Oct 2004	25,000	$4.17	-	-
5/04	Nov 2004 - Mar 2005	60,000	$5.04	30,000	$6.00
2/04	Apr 2005- Oct 2005	33,000	$3.10	16,000	$4.43
	Colorado Interstate Gas (CIG) Based Hedges (Wattenberg Field)				
7/04	Nov 2004 - Mar 2005	80,000	$5.00	40,000	$6.20
	NYMEX Based Hedges (Williams acquisition)				
6/03	Jul 2004 - Dec 2004	150,000	$4.50	-	-
7/04	Jan 2005 - Mar 2005	150,000	$5.32	-	-
2/04	Apr 2005 - Oct 2005	150,000	$4.26	75,000	$5.00
	Oil hedges (Wattenberg Field)				
	Month	Monthly Quantity barrels	Contract Price		
2/04	Jul 2004 - Dec 2004	10,000	$31.63		

Well Operations, Pipeline and Other Income

Well operations and pipeline income for the three months ended June 30, 2004 was $1.9 million compared to $1.8 million for the three months ended June 30, 2003, an increase of approximately $100,000 or 5.6 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 June 30, 2004 was $687,000 compared to $285,000 for the three months ended June 30, 2003.

Costs and Expenses

Costs and expenses for the three months ended June 30, 2004 were $60.5 million compared to $35.3 million for the three months ended June 30, 2003, an increase of approximately $25.2 million or 71.4 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.

Oil and Gas Well Drilling Operations Costs

Oil and gas well drilling operations costs for the three months ended June 30, 2004 were $25.0 million compared to $10.1 million for the three months ended June 30, 2003, an increase of approximately $14.9 million or 148 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above.

Cost of Gas Marketing Activities

The costs of gas marketing activities for the three months ended June 30, 2004 were $25.6 million compared to $17.1 million for the three months ended June 30, 2003, an increase of $8.5 million or 49.7 percent. The increase was due to higher volumes of natural gas purchased for resale, along with higher average purchase prices. Income before income taxes for the Company's natural gas marketing subsidiary improved from $125,000 for the three months ended June 30, 2003 to $360,000 for the three months ended June 30, 2004. 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 June 30, 2004 were $4.0 million compared to $3.5 million for the three months ended June 30, 2003, an increase of approximately $500,000 or 14.3 percent. Such increase was due to the increased production costs on the increased volumes 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 $0.98 per Mcfe during the three months ended June 30, 2003 to $1.02 per Mcfe during the three months ended June 30, 2004, primarily as a result of production taxes on higher average prices of gas and oil sold.

General and Administrative Expenses

General and administrative expenses for the three months ended June 30, 2004 were $900,000 compared to $1.2 million for the three months ended June 30, 2003, a decrease of approximately $300,000 or 25%. Such decrease was due to the change of and restructuring of executives' compensation offset in part by increased administrative activity associated with an expanding Company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended June 30, 2004 increased to $4.7 million from approximately $3.1 million for the three months ended June 30, 2003, an increase of approximately $1.6 million or 51.6 percent. Such increase was due to the significantly increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest costs for the three months ended June 30, 2004 and 2003 remained relatively constant at approximately $250,000 in both periods. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 33 percent to 36 percent primarily as a result of the application of higher tax rates due to significantly increased earnings of the Company during 2004 and other miscellaneous permanent differences which are not expected in 2004.

Net income and Earnings Per Share

Net income for the three months ended June 30, 2004 was $8.6 million compared to a net income of $4.6 million for the three months ended June 30, 2003, an increase of approximately $4.0 million or 87 percent.

Diluted earnings per share for the three months ended June 30, 2004 was $0.52 per share compared to $0.29 per share for the three months ended June 30, 2003, an increase of $0.23 per share or 79.3 percent.

Six Months Ended June 30, 2004 Compared with June 30, 2003

Revenues

Total revenues for the six months ended June 30, 2004 were $145.0 million compared to $96.2 million for the six months ended June 30, 2003, an increase of approximately $48.8 million or 50.7 percent. Such increase was a result of increased drilling revenues, sales from gas marketing activities, oil and gas sales and well operations and pipeline income.

Drilling Revenues

Drilling revenues for the six months ended June 30, 2004 were $59.0 million compared to $33.4 million for the six months ended June 30, 2003, an increase of approximately $25.6 million or 76.6 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The Company started the second quarter of 2004 with advances for future drilling from March 31, 2004 of $21.0 million compared with advances for future drilling of $15.5 million at the beginning of the second quarter of 2003. During the second quarter of 2004 the Company funded its first drilling program of the year with subscriptions of $29.0 million compared to an $8.4 million program funded during the second quarter of 2003. Both programs commenced drilling operations shortly after funding. We believe in part that this increase results from higher oil and natural gas prices which have improved the performance of our prior programs helping 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 marketing subsidiary, for the six months ended June 30, 2004 were $49.5 million compared to $39.0 million for the six months ended June 30, 2003, an increase of approximately $10.5 million or 26.9 percent. Such increase was due to higher volumes of natural gas sold, along with higher average sales prices.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the six months ended June 30, 2004 were $32.1 million compared to $19.8 million for the six months ended June 30, 2003 an increase of $12.3 million or 62.1 percent. The increase was due to significantly increased volumes sold at higher average sales prices of oil and natural gas. The volume of natural gas sold for the six months ended June 30, 2004 was 5.2 million Mcf at an average sales price of $4.96 per Mcf compared to 3.8 million Mcf at an average sales price of $4.41 per Mcf for the six months ended June 30, 2003. Oil sales were 200,200 barrels at an average sales price of $32.11 per barrel for the six months ended June 30, 2004 compared to 115,000 barrels at an average sales price of $27.80 per barrel for the six months ended June 30, 2003. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily the Williams property acquisition in the second quarter of 2003, recompletions of existing wells, two fourth quarter 2003 acquisitions of oil and gas properties in Colorado and Kansas and the investment in oil and gas properties we own in our public drilling program partnerships.

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

	Six Months Ended June 30, 2004			Six Months Ended June 30, 2003		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	2,342	888,258	902,310	2,014	973,446	985,530
Michigan Basin	3,004	869,816	887,840	3,294	933,075	952,839
Rocky Mountains	194,894	3,411,388	4,580,752	109,827	1,855,274	2,514,236
Total	200,240	5,169,462	6,370,902	115,135	3,761,795	4,452,605
Average Price	$32.11	$4.96	$5.03	$27.80	$4.41	$4.44

Our financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas and oil markets has remained prevalent in the last few years and can have a material impact on our financial results. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. The Company 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the local demand/pipeline capacity problem. The Company has commodity price hedging contracts for oil and natural gas production from July 2004 through October 2005 to protect against possible short-term price weaknesses. See Management's Discussion and Analysis for the three months ended June 30, 2004 compared with June 30, 2003 for a complete schedule of current hedging positions.

Well Operations, Pipeline and Other Income

Well operations and pipeline income for the six months ended June 30, 2004 was $3.7 million compared to $3.4 million for the six months ended June 30, 2003, an increase of approximately $300,000 or 8.8 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 six months ended June 30, 2004 was $745,000 compared to $670,000 for the six months ended June 30, 2003.

Costs and Expenses

Costs and expenses for the six months ended June 30, 2004 were $118.3 million compared to $81.8 million for the six months ended June 30, 2003, an increase of approximately $36.5 million or 44.6 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.

Oil and Gas Well Drilling Operations Costs

Oil and gas well drilling operations costs for the six months ended June 30, 2004 were $50.3 million compared to $27.8 million for the six months ended June 30, 2003, an increase of approximately $22.5 million or 80.9 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above. In addition, the gross margin on the drilling activities for the six months ended June 30, 2004 was 14.6% compared with 16.7% for the six months ended June 30, 2003, a decrease in gross margin of 2.1%. Such decrease was due to increasing well drilling costs particularly the cost of well fracturing and rising steel costs for casing and other well equipment. For competitive reasons the company currently does not plan to increase charges to its investor partners at this time and as a result anticipates a continuation of lower margins in 2004 compared to the prior year.

Cost of Gas Marketing Activities

The cost of gas marketing activities for the six months ended June 30, 2004 were $48.5 million compared to $38.5 million for the six months ended June 30, 2003, an increase of $10 million or 26 percent. The increase was due to higher volumes of natural gas purchased for resale, along with higher average purchase prices. Income before income taxes for the Company's natural gas marketing subsidiary improved from $245,000 for the six months ended June 30, 2003 to $961,000 for the six months ended June 30, 2004. 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 six months ended June 30, 2004 were $7.9 million compared to $6.3 million for the six months ended June 30, 2003, an increase of approximately $1.6 million or 25.4 percent. Such increase was due to the increased production costs on the increased volumes 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 $0.99 per Mcfe during the six months ended June 30, 2003 to $1.00 per Mcfe during the six months ended June 30, 2004.

General and Administrative Expenses

General and administrative expenses for the six months ended June 30, 2004 were $1.9 compared to $2.4 million for the six months ended June 30, 2003, a decrease of approximately $500,000 or 20.8 percent. Such decrease was due to the change of and restructuring of executives' compensation offset in part by increased administrative activity associated with an expanding Company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the six months ended June 30, 2004 increased to $9.2 million from approximately $6.4 million for the six months ended June 30, 2003, an increase of approximately $2.8 million or 43.8 percent. Such increase was due to the significantly increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest costs for the six months ended June 30, 2004 and 2003 remained relatively constant at approximately $500,000 in both periods. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 33 percent to 36 percent primarily as a result of the application of higher tax rates due to significantly increased earnings of the Company during 2004 and other miscellaneous permanent differences which are not expected in 2004.

Net income and Earnings Per Share

Net income for the six months ended June 30, 2004 was $17.1 million compared to a net income of $9.4 million for the six months ended June 30, 2003, an increase of approximately $7.7 million or 81.9 percent.

Diluted earnings per share for the six months ended June 30, 2004 was $1.04 per share compared to $0.59 per share for the six months ended June 30, 2003, an increase of $0.45 per share or 76.3 percent.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations, capital raised through drilling partnerships 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, well drilling and operating activities from the Company's public drilling programs, 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.

Natural Gas Pricing and Pipeline Capacity

Natural gas and oil prices have been volatile in the past, and the Company anticipates continued volatility in the future. Currently, the NYMEX futures reflect a market expectation of continuing strong natural gas prices at Henry Hub. Although prices look strong for the remainder of 2004, natural gas storage levels are above normal levels following a period when storage levels had been at five-year lows. The Company believes this situation creates the possibility of periods of both low prices and continued high prices.

Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. The Company 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity problem.

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 gas prices. Through October 2005 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 previous pages in this Management's Discussion and Analysis for the 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.

Oil Pricing

Oil prices have strengthened since the middle of 2003. While oil prices are influenced by supply and demand, global geopolitics may be the single most important determinant. Since the percentage of the Company's production reflected by oil sales has increased to approximately 20% during the six months of 2004, variations in oil prices will have a greater impact on the Company than in the past. The Company also has in place hedges on 10,000 barrels a month for its Wattenberg Field oil production for the period from July 2004 through December 2004 at a price of $31.63 per barrel.

Public Drilling Programs

The Company closed its first partnership (PDC 2004-A) in its PDC 2004-2006 Drilling Program of 2004 in the second quarter and is drilling the wells in the second and third quarters of 2004. This first partnership of 2004 closed with record investor subscriptions of $29.0 million compared to $8.5 million for the first program of 2003.

The Company also closed its second Partnership (PDC 2004-B) of 2004 on July 2, 2004 at a record for a second program at its maximum allowable of $18 million in investor subscriptions nearly two months before its scheduled close. Additional partnerships are scheduled to close in October and December of 2004, with maximum subscriptions of $18 million and $35 million, respectively. Both programs are likely to close early at their maximum allowable subscriptions.

The Company posts daily the current amount of subscriptions in the current partnership at its website, www.petd.com, under the heading of "Drilling Program".

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 the current program or future programs.

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 months' 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 the investors, is currently approximately $5.6 million. The Company has adequate liquidity to meet this obligation. During the first six months of 2004 the Company has spent $246,800 under this provision.

Common Stock Repurchase

On March 13, 2003 the Company publicly announced a common stock repurchase program to repurchase up to 5% of the Company's outstanding common stock (785,000 shares) expiring on December 31, 2004. From inception of the program until June 30, 2004, the Company has repurchased 109,200 shares at an average price of $6.86 per share. The Company intends to fund this repurchase of common stock through internally generated cash flow.

Long-Term Debt

The Company has a credit facility with J. P. Morgan (formerly Bank One, NA) and BNP Paribas of $100 million subject to adequate oil and natural gas reserves. Currently the borrowing base is set at $80 million while the Company's total oil and gas reserves calculated under this method is in excess of $100 million. As of June 30, 2004 the Company had activated $60 million of this facility. As of June 30, 2004, the outstanding balance on the line of credit was $30.0 million of which $10.0 million was subject to an interest rate swap at a rate of 8.39% and $20.0 million was subject to a prime rate of 4.25%. The above interest rate swap expires on October 12, 2004 at which time the Company will benefit from lower effective interest rate on $10 million of its outstanding credit balance. The line of credit is at prime, with LIBOR alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires. In the second quarter of 2004, the banks and the Company extended the expiration date of the credit agreement until July 3, 2008.

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	$30,000,000	-	-	30,000,000	-
Operating Leases	658,800	254,000	291,600	113,200	-
Asset Retirement Obligation	749,200	-	50,000	50,000	649,200
Other Liabilities	2,874,800	125,000	250,000	250,000	2,249,800
Total	$34,282,800	379,000	591,600	30,413,200	2,899,000

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 10 private partnerships and 60 public partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company believes its casualty insurance coverage is adequate to meet this potential liability.

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 accounting policies" in our annual financial statements and related notes. Our critical accounting policies and estimates are as follows:

Revenue Recognition

Oil and gas wells are drilled primarily on a contract basis. The Company follows the percentage-of-completion method of income recognition for drilling operations in progress.

Sales of natural gas are recognized when sold, oil revenues are recognized when produced into a stock tank.

Well operations income consists of operation charges for well upkeep, maintenance and operating lease income on tangible well equipment.

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.

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

Depreciation, Depletion and Amortization

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

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

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, 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. See additional discussions in this Management's Discussion and Analysis.

New Accounting Standards

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that required entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement was effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $198,600 (net of taxes of $121,700).

In December 2002, the FASB issued SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure", an amendment of FASB Statement No. 123. This statement amended SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amended the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Disclosures required by this standard are included in the notes to these financial statements.

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.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights (leases) associated with extracting oil and gas intangible assets in the balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify the historical cost of approximately $7,226,600 and $7,576,900 of mineral rights associated with undeveloped oil and gas properties as of June 30, 2004 and December 31, 2003, respectively, and $16,929,100 and $15,485,500 of mineral rights associated with developed oil and gas properties as of June 30, 2004 and December 31, 2003, respectively out of oil and gas properties and into a separate intangible mineral rights assets line item. The Company's total balance sheet, cash flows and results of operations would be not affected since such intangible assets would continue to be amortized and assessed for impairment. There is a proposed FASB staff position issued that clarifies that reclassification will not be necessary under the exception to SFAS No. 142 but the comment period is still open. Final resolution is expected by the end of the Company's third quarter.

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, 2003.

Commodity Price Risk

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its 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 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 June 30, 2004 and June 30, 2003.

Riley Natural Gas
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of June 30, 2004					
Natural Gas	Sale	3,660,000	$5.10	$18,681,050	($4,314,400)
Natural Gas	Purchase	430,000	$5.53	$2,378,320	$269,300
Natural Gas	Sale Option	270,000	$4.75		$0
Natural Gas	Purchase Option	135,000	$6.74		($1,440)

Contracts maturing in 12 months following June 30, 2004					
Natural Gas	Sale	2,480,000	$5.25	$13,031,180	($2,664,360)
Natural Gas	Purchase	430,000	$5.53	$2,378,320	$269,300
Natural Gas	Sale Option	270,000	$4.75		$0
Natural Gas	Purchase Option	135,000	$6.74		($1,440)
Prior Year Total Contracts as of June 30, 2003					
Natural Gas	Sale	3,580,000	$4.38	$15,690,730	($3,445,960)
Natural Gas	Purchase	360,000	$5.20	$1,872,430	$33,530

The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 36 months.

Petroleum Development Corporation
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of June 30, 2004					
Natural Gas	Purchase	21,552	$4.73	$101,941	$33,976
Natural Gas	Sale Option	5,114,680	$4.48		$0
Natural Gas	Purchase Option	2,035,500	$5.45		($1,162,953)
Oil	Sale	68,868	$31.63	$2,178,294	($378,889)
Contracts maturing in 12 months following June 30, 2004					
Natural Gas	Purchase	21,552	$4.73	$101,941	$33,976
Natural Gas	Sale Option	4,063,144	$4.40		$0
Natural Gas	Purchase Option	1,509,732	$5.41		($641,391)
Oil	Sale	68,868	$31.63	$2,178,294	($378,889)
Prior Year Total Contracts as of June 30, 2003					
Natural Gas	Sale	490,000	$4.78	$2,342,000	($261,000)
Natural Gas	Sale Option	4,499,900	$4.29	$0	$195,648
Natural Gas	Purchase Option	913,700	$4.96	$0	($706,894)
Oil	Sale	33,386	$30.00	$1,001,592	$36,002

The maximum term over which PDC is hedging exposure to the variability of cash flows for commodity price risk is 16 months.

The average NYMEX closing price for natural gas for the years 2003 and 2002 was $5.39 Mmbtu and $3.22 Mmbtu. The average NYMEX closing price for oil for the years 2003 and 2002 was $30.98 bbl and $26.98 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 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. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number Of Shares Purchased(1)	(b) Average Price Paid per Share (1)	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (2)
May 1 - May 31, 2004	50,487	$27.73	-	-
June 1 - June 30, 2004	1,703	$32.01		
Total	52,190	$27.87	-	-

(1) On May 20, 2004 the Company purchased 50,487 shares from the estate of one of the Company's former officers in accordance with terms of the former officer's employment agreement. The repurchase price of the stock was $27.73 per share based upon the 90-day average prior to the repurchase as per that contract. The repurchase totaled $1,400,000.

On June 3, 2004 the Company purchased 1,703 shares from an employee at retirement at a price of $32.01 per share at fair market value as of the date of retirement for a total purchase price of $54,513.

(2) On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program is scheduled to expire on December 31, 2004. See Note 9 to the financial statements above.

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

The Company held its annual meeting of shareholders on June 11, 2004. For the results of the meeting, see the Company's Form 8-K dated June 11, 2004.

Item 6. Exhibits and Reports on Form 8-K

(a) 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	32.1	Filed herewith.
Section 1350 Certification by Chief Financial Officer	32.2	Filed herewith.

(b) Reports on Form 8-K during the quarter ended June 30, 2004.

Form 8-K current report dated May 5, 2004, under Item 5, "Other Matters", the Company issued a news release announcing financial and operating results for the first quarter 2004.

Form 8-K current report dated May 11, 2004, under Item 5, "Other Matters", the Company issued a news release announcing that is has closed its first 2004 Partnership with record $29 Million in subscriptions.

Form 8-K current report dated May 12, 2004, under Item 5, "Other Matters", the Company issued a news release announcing that is has added to previously announced natural gas and oil commodities options positions.

Form 8-K current report dated June 11, 2004, under Item 5, "Other Matters", the Company issued a news release announcing that shareholders of the company re-elected Vincent F. D'Annunzio and Thomas E. Riley to the Board of Directors of the company for a three-year term and David C. Parke to the Board of Directors of the company for a one year term. Each of the directors received 99 percent of the votes cast in favor of their re-election. The shareholders ratified the selection of KPMG LLP as independent auditors for the fiscal year ending December 31, 2004. The shareholders also approved the 2004 Long-Term Equity Compensation Plan and the Non-Employee Director Deferred Compensation Plan.

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: July 30, 2004

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

Date: July 30, 2004

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