CONFORMED COPY

**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, 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: 16,245,484 shares of the Company's Common Stock ($.01 par value) were outstanding as of March 31, 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

INDEX

PART I - FINANCIAL INFORMATION

PART I - FINANCIAL INFORMATION

Independent Auditors' Review Report

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, 2004, the related condensed consolidated statements of income for the three-month periods ended March 31, 2004 and 2003, and the related condensed consolidated statements of cash flows for the three-month periods ended March 31, 2004 and 2003. These condensed consolidated financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. 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 generally accepted auditing standards, 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 accounting principles generally accepted in the United States of America.

KPMG LLP

Pittsburgh, Pennsylvania
May 2, 2004

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets
March 31, 2004 and December 31, 2003

ASSETS

| | 2004 (Unaudited) | 2003 |
|---|---|---|
| Current assets: | | |
| Cash and cash equivalents | $55,640,100 | 80,379,300 |
| Accounts and notes receivable | 24,517,900 | 22,523,600 |
| Inventories | 1,969,500 | 2,557,700 |
| Prepaid expenses | 6,432,000 | 5,907,000 |
| Total current assets | 88,559,500 | 111,367,600 |
| Properties and equipment | 266,910,300 | 265,864,300 |
| Less accumulated depreciation, depletion, and amortization | 75,582,000 | 71,182,100 |
| | 191,328,300 | 194,682,200 |
| Other assets | 624,900 | 672,200 |
| | $280,512,700 | 306,722,000 |

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued
March 31, 2004 and December 31, 2003

| LIABILITIES AND STOCKHOLDERS' EQUITY | 2004 (Unaudited) | 2003 |
|---|---|---|
| Current liabilities: | | |
| Accounts payable and accrued expenses | $44,520,300 | 46,267,200 |
| Advances for future drilling contracts | 20,959,600 | 50,458,800 |
| Funds held for future distribution | 11,523,700 | 8,410,900 |
| Total current liabilities | 77,003,600 | 105,136,900 |
| Long-term debt | 42,000,000 | 53,000,000 |
| Other liabilities | 2,618,000 | 2,449,100 |
| Deferred income taxes | 23,821,100 | 21,800,200 |
| Asset retirement obligations | 740,200 | 731,200 |
| Stockholders' equity: | | |
| Common stock | 162,400 | 156,200 |
| Additional paid-in capital | 32,060,300 | 28,578,100 |
| Retained earnings | 104,488,600 | 96,049,200 |
| Accumulated other comprehensive income, net | (2,381,500) | (1,178,900) |
| Total stockholders' equity | 134,329,800 | 123,604,600 |
| | $280,512,700 | 306,722,000 |

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Income
Three Months ended March 31, 2004 and 2003
(Unaudited)

| | 2004 | 2003 |
|---|---|---|
| Revenues: | | |
| Oil and gas well drilling operations | $29,499,300 | $21,497,500 |
| Gas sales from marketing activities | 23,457,400 | 21,605,100 |
| Oil and gas sales | 16,196,200 | 8,858,800 |
| Well operations and pipeline income | 1,837,500 | 1,648,300 |
| Other income | 58,100 | 384,700 |
| | 71,048,500 | 53,994,400 |
| Costs and expenses: | | |
| Cost of oil and gas well drilling operations | 25,355,700 | 17,675,800 |
| Cost of gas marketing activities | 22,854,700 | 21,482,700 |
| Oil and gas production costs | 3,906,100 | 2,721,700 |
| General and administrative expenses | 994,200 | 1,177,700 |
| Depreciation, depletion, and amortization | 4,507,700 | 3,245,600 |
| Interest | 243,500 | 236,200 |
| | 57,861,900 | 46,539,700 |
| Income before income taxes and cumulative effect of change in accounting principle | 13,186,600 | 7,454,700 |
| Income taxes | 4,747,200 | 2,460,000 |
| Net income before cumulative effect of change in accounting principle | 8,439,400 | 4,994,700 |
| Cumulative effect of change in accounting principle (net of taxes of $121,700) | -- | (198,600) |
| Net income | $8,439,400 | $4,796,100 |
| Basic earnings per common share before accounting change | $0.53 | $0.32 |
| Cumulative effect of change in accounting principle | - | (0.01) |
| Basic earnings per common share | $0.53 | $0.31 |
| Diluted earnings per share before accounting change | $0.52 | $0.31 |
| Cumulative effect of change in accounting principle | - | (0.01) |
| Diluted earnings per share | $0.52 | $0.30 |

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, 2004 and 2003
(Unaudited)

| | 2004 | 2003 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income | $ 8,439,400 | 4,796,100 |
| Adjustments to net income to reconcile to cash used in operating activities: | | |
| Deferred federal income taxes | 2,786,600 | 1,659,000 |
| Depreciation, depletion & amortization | 4,507,700 | 3,245,600 |
| Cumulative effect of change in accounting principle | - | 198,600 |
| Accretion of asset retirement obligation | 9,000 | 8,900 |
| Loss/(gain) from sale of assets | 3,000 | (110,900) |
| Leasehold acreage expired or surrendered | 51,000 | 555,900 |
| Amortization of stock award | 900 | 1,400 |
| Increase in current assets | (20,600) | (6,372,400) |
| Decrease in other assets | 18,800 | 2,119,300 |
| Decrease in current liabilities | (28,915,700) | (10,317,700) |
| Increase (decrease) in other liabilities | 168,900 | (2,015,200) |
| Total adjustments | (21,390,400) | (11,027,500) |
| Net cash used in operating activities | (12,951,000) | (6,231,400) |
| Cash flows from investing activities: | | |
| Capital expenditures | (1,825,800) | (3,305,500) |
| Proceeds from sale of leases | 624,100 | 429,200 |
| Proceeds from sale of fixed assets | 22,400 | 117,600 |
| Net cash used in investing activities | (1,179,300) | (2,758,700) |
| Cash flows from financing activities: | | |
| Retirement of long-term debt | (11,000,000) | (2,000,000) |
| Proceeds from issuance of common stock | 1,685,700 | - |
| Repurchase and cancellation of treasury stock | (1,294,600) | (282,900) |
| Net cash used in financing activities | (10,608,900) | (2,282,900) |
| Net decrease in cash and cash equivalents | (24,739,200) | (11,273,000) |
| Cash and cash equivalents, beginning of period | 80,379,300 | 51,023,500 |
| Cash and cash equivalents, end of period | $55,640,100 | 39,750,500 |

See accompanying notes to unaudited condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
March 31, 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 quarters ended March 31, 2004 or March 31, 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:

| | March 31, | |
|---|---|---|
| | 2004 | 2003 |
| Net income, as reported | $8,439,400 | 4,796,100 |
| Deduct total stock-based employee compensation expense determined under fair-value-based method for all awards, net of tax | - | - |
| Pro forma net income | $8,439,400 | 4,796,100 |
| Basic earnings per share as reported | $0.53 | 0.31 |
| Pro forma basic earnings per share | $0.53 | 0.31 |
| Diluted earnings per share as reported | $0.52 | 0.30 |
| Pro forma diluted earnings per share | $0.52 | 0.30 |

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, 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

Computations of earnings per common and common equivalent share are as follows for the three months ended March 31:

| | 2004 | 2003 |
|---|---|---|
| Weighted average common shares outstanding | 15,861,897 | 15,725,755 |
| Weighted average common and common equivalent shares outstanding | 16,304,526 | 15,998,584 |
| Net income before cumulative effect of change in accounting principle | $8,439,400 | 4,994,700 |
| Cumulative effect of change in accounting principle (net of taxes of $121,700) | - | (198,600) |
| Net income | $8,439,400 | 4,796,100 |
| Basic earnings per common share before accounting change | $0.53 | 0.32 |
| Cumulative effect of change in accounting principle | - | (0.01) |
| Basic earnings per common share | $0.53 | 0.31 |
| Diluted earnings per share before accounting change | $0.52 | 0.31 |
| Cumulative effect of change in accounting principle | - | (0.01) |
| Diluted earnings per share | $0.52 | 0.30 |

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. 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 2,500 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 months ended March 31, 2004 and 2003 is as follows:

| | 2004 | 2003 |
|---|---|---|
| REVENUES | | |
| Drilling and Development | $29,500 | 21,497 |
| Natural Gas Marketing | 23,457 | 21,605 |
| Oil and Gas Sales | 16,196 | 8,858 |
| Well Operations | 1,838 | 1,648 |
| Unallocated amounts (1) | 58 | 386 |
| Total | 71,049 | 53,994 |
| | | |
| SEGMENT INCOME BEFORE INCOME TAXES | | |
| Drilling and Development | 4,144 | 3,822 |
| Natural Gas Marketing | 601 | 120 |
| Oil and Gas Sales | 8,802 | 3,887 |
| Well Operations | 920 | 734 |
| Unallocated amounts (2) | | |
| General and Administrative expenses | (994) | (1,178) |
| Interest expense | (244) | (236) |
| Other (1) | (42) | 306 |
| Total | $13,187 | 7,455 |
| | March 31, 2004 | December 31, 2003 |
| SEGMENT ASSETS | | |
| Drilling and Development | $41,798 | 62,546 |
| Natural Gas Marketing | 21,037 | 17,006 |
| Oil and Gas Sales | 195,596 | 204,849 |
| Well Operations | 11,595 | 11,602 |
| Unallocated amounts | | |
| Cash | 815 | 800 |
| Other | 5,568 | 9,919 |
| Total | $280,513 | 306,722 |

(1) Includes interest on investments and partnership management fees and gain on sale of assets 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 quarter ended March 31, 2004 and 2003.

| | 2004 | 2003 |
|---|---|---|
| Net Income before cumulative effect of change in accounting principle | $8,439,400 | $ 4,994,700 |
| Cumulative effect on prior years of SFAS 143 - "Accounting for Asset Retirement Obligations" (net of taxes of $121,700) | - | (198,600) |
| Net income | 8,439,400 | 4,796,100 |
| Other Comprehensive Income (loss) (net of tax): | | |
| Reclassification adjustment for settled contracts included in net income (net of tax of $134,400, and $228,600, respectively) | 211,100 | 372,900 |
| Change in fair value of outstanding hedging positions (net of tax of $900,000 and $671,000, respectively) | (1,413,700) | (1,095,000) |
| Other Comprehensive Income (loss) | (1,202,600) | (722,100) |
| Comprehensive Income | $7,236,800 | $4,074,000 |

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 quarter 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 $5.2 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 March 31, 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 totalled $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.

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 taxes of $121,700).

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

### Results of Operations

### Three Months Ended March 31, 2004 Compared with March 31, 2003

Revenues

Total revenues for the three months ended March 31, 2004 were $71.0 million compared to $54.0 million for the three months ended March 31, 2003, an increase of approximately $17.0 million or 31.5 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 March 31, 2004 were $29.5 million compared to $21.5 million for the three months ended March 31, 2003, an increase of approximately $8.0 million or 37.2 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 2004 with advances for future drilling from December 31, 2003 of $50.5 million compared with advances for future drilling of $37.3 million at the beginning of the first quarter of 2003. We believe 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 marketing subsidiary for the three months ended March 31, 2004 were $23.5 million compared to $21.6 million for the three months ended March 31, 2003, an increase of approximately $1.9 million or 8.8 percent. Such increase was due to higher volumes of natural gas sold, offset in part by slightly lower average sales prices.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended March 31, 2004 were $16.2 million compared to $8.9 million for the three months ended March 31, 2003 an increase of $7.3 million or 82.0 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 March 31, 2004 was 2.6 million Mcf at an average sales price of $4.91 per Mcf compared to 1.6 million Mcf at an average sales price of $4.49 per Mcf for the three months ended March 31, 2003. Oil sales were 104,000 barrels at an average sales price of $31.84 per barrel for the three months ended March 31, 2004 compared to 57,000 barrels at an average sales price of $26.02 per barrel for the three months ended March 31, 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.

Oil and Gas Production

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

| | Three Months Ended March 31, 2004 | | | Three Months Ended March 31, 2003 | | |
|---|---|---|---|---|---|---|
| | Oil (Bbl) | Natural Gas (Mcf) | Natural Gas Equivalents (Mcfe) | Oil (Bbl) | Natural Gas (Mcf) | Natural Gas Equivalents (Mcfe) |
| Appalachian Basin | 1,204 | 457,218 | 464,442 | 802 | 504,562 | 509,374 |
| Michigan Basin | 1,151 | 443,962 | 450,868 | 1,832 | 485,228 | 496,220 |
| Rocky Mountains | 101,781 | 1,721,812 | 2,332,498 | 54,209 | 653,535 | 978,789 |
| Total | 104,136 | 2,622,992 | 3,247,808 | 56,843 | 1,643,325 | 1,984,383 |
| Average Sales Price | $31.84 | $4.91 | $4.99 | $26.02 | $4.49 | $4.46 |

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 April 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 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. During the three months ended March 31, 2004 the Company averaged natural gas volumes sold of 874,000 Mcf per month and oil sales of 34,700 barrels per month. The current positions in effect on the Company's share of production are shown in the following table.

| | Floors | | Ceilings | |
|---|---|---|---|---|
| Month | Monthly Quantity Mmbtu | Contract Price | Monthly Quantity Mmbtu | Contract Price |
| NYMEX Based Hedges - (Appalachian and Michigan Basins) | | | | |
| Apr 2004 - Oct 2004 | 81,000 | $4.00 | 81,000 | $5.65 |
| Apr 2004 - Oct 2004 | 122,000 | $5.00 | - | - |
| Apr 2005 - Oct 2005 | 122,000 | $4.28 | 61,000 | $5.00 |
| | | | | |
| Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin) | | | | |
| Apr 2004 - Oct 2004 | 25,000 | $3.20 | 25,000 | $4.70 |
| Apr 2004 - Oct 2004 | 25,000 | $4.17 | - | - |
| Apr 2005- Oct 2005 | 33,000 | $3.10 | 16,000 | $4.43 |
| | | | | |
| NYMEX Based Hedges (Williams acquisition) | | | | |
| Apr 2004 - Dec 2004 | 150,000 | $4.50 | - | - |
| Apr 2005 - Oct 2005 | 150,000 | $4.26 | 75,000 | $5.00 |

Oil hedges (Wattenberg Field)

| Month | Monthly Quantity Bbl | Contract Price |
|---|---|---|
| Apr 2004 - Dec 2004 | 10,000 | $31.63 |

Well Operations, Pipeline and Other Income

Well operations and pipeline income for the three months ended March 31, 2004 was $1.8 million compared to $1.6 million for the three months ended March 31, 2003, an increase of approximately $200,000 or 12.5 percent. Such increase was due to an increase in the number of wells and pipeline systems operated by the Company for our drilling fund partnerships as well as third parties . Other income for the three months ended March 31, 2004 was $58,000 compared to $385,000 for the three months ended March 31, 2003. Such decrease was due to a decrease in interest income as the Company had lower average cash balances during the first quarter of 2004 compared to 2003. The Company utilized its cash balances to reduce its line of credit during the period.

Costs and Expenses

Costs and expenses for the three months ended March 31, 2004 were $57.9 million compared to $46.5 million for the three months ended March 31, 2003, an increase of approximately $11.4 million or 24.5 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 March 31, 2004 were $25.4 million compared to $17.7 million for the three months ended March 31, 2003, an increase of approximately $7.7 million or 43.5 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 three months ended March 31, 2004 was 14.1% compared with 17.8% for the three months ended March 31, 2003, a decrease in gross margin of 3.7%. 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 three months ended March 31, 2004 were $22.9 million compared to $21.5 million for the three months ended March 31, 2003, an increase of $1.4 million or 6.5 percent. The increase was due to higher volumes of natural gas purchased for resale, offset in part by slightly lower average purchase prices. Income before income taxes for the Company's natural gas marketing subsidiary improved from $120,000 for the three months ended March 31, 2003 to $601,000 for the three months ended March 31, 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 March 31, 2004 were $3.9 million compared to $2.7 million for the three months ended March 31, 2003, an increase of approximately $1.2 million or 44.4 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 decreased from $1.02 per Mcfe during the three months ended March 31, 2003 to $.98 per Mcfe during the three months ended March 31, 2004.

General and Administrative Expenses

General and administrative expenses for the three months ended March 31, 2004 were $994,000 compared to $1.2 million for the three months ended March 31, 2003, a decrease of approximately $200,000 or 16.7%. 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 March 31, 2004 increased to $4.5 million from approximately $3.2 million for the three months ended March 31, 2003, an increase of approximately $1.3 million or 40.6 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 March 31, 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 the utilization in 2003 of alternative minimum tax credit carry-forwards and other miscellanenous permanent differences which are not expected in 2004.

Change in Accounting Principle

The Company adopted SFAS No. 143 *"Accounting for Asset Retirement Obligations"* on January 1, 2003 and recorded the cumulative effect on prior years of $198,600 (net of taxes of $121,700).

Net income and Earnings Per Share

Net income for the three months ended March 31, 2004 was $8.4 million compared to a net income of $4.8 million for the three months ended March 31, 2003, an increase of approximately $3.6 million or 75% percent.

Diluted earnings per share for the three months ended March 31, 2004 was $0.52 per share compared to $0.30 per share for the three months ended March 31, 2003, an increase of $0.22 per share or 73.3 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 gas prices at Henry Hub of continuing strong natural gas prices. Although prices look strong for the remainder of 2004, natural gas storage levels are near 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 first quarter 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 April 2004 through December 2004 at a price of $31.60 per barrel.

Public Drilling Programs

During the first quarter of 2004, the Company commenced sales of the first Partnership (PDC 2004-A) in its PDC 2004-2006 Drilling Program. Sales have been very strong and on May 3, 2004 the Company closed the program at approximately $30 million of subscriptions for wells to be drilled during the second and third quarters of 2004. Sales of the PDC 2004-A partnership significantly exceed sales of the first programs sold in prior years. The largest first program in prior years had $9.3 million in subscriptions.

Additional programs are scheduled to close in August, October and December of 2004. The maximum total subscriptions the company plans to accept in 2004 is $100 million. 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 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 $5.2 million. The Company has adequate liquidity to meet this obligation. During the first three months of 2004 the Company has spent $134,200 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 March 31, 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 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 March 31, 2004 the Company had activated $60 million of this facility. As of March 31, 2004, the outstanding balance on the line of credit was $42.0 million of which $10.0 million was subject to an interest rate swap at a rate of 8.39% and $32.0 million was subject to a prime rate of 4.00%. 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 on July 3, 2005. The Company anticipates extending the expiration date during the second quarter of 2004.

Contractual Obligations

Contractual obligations and due dates are as follows:

| | Payments due by period | | | | |
|---|---|---|---|---|---|
| Contractual Obligations | Total | Less than 1 year | 1-3 years | 3-5 years | More than 5 years |
| Long-Term Debt | $42,000,000 | - | $42,000,000 | - | - |
| Operating Leases | 739,700 | $279,100 | 321,700 | $138,900 | - |
| Asset Retirement Obligation | 740,200 | - | 50,000 | 50,000 | $640,200 |
| Other Liabilities | $2,618,000 | 125,000 | 250,000 | 250,000 | 1,993,000 |
| Total | $46,097,900 | $404,100 | $42,621,700 | $438,900 | $2,633,200 |

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 partnership and 58 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

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

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.

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 $7,091,400 and $7,576,900 of mineral rights associated with undeveloped oil and gas properties as of March 31, 2004 and December 31, 2003, respectively, and $15,485,500 and $15,485,500 of mineral rights associated with developed oil and gas properties as of March 31, 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.

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 Bank One 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.

As of March 31, 2004 RNG had entered into a series of natural gas future contracts and option contracts stemming from its marketing activities. Total open futures contracts are for the sale of 3,380,000 Mmbtu of natural gas with a weighted average price of $4.77 Mmbtu resulting in a total contract amount of $16,115,800 and a fair market value of $(3,286,000) and for the purchase of 580,000 Mmbtu of natural gas with a weighted average price of $4.90 Mmbtu resulting in a total contract amount of $2,402,300 and a fair market value of $397,400. Open future contracts maturing in the next twelve months are for the sale of 2,200,000 Mmbtu of natural gas with a weighted average price of $4.84 Mmbtu resulting in a total contract amount of $10,643,500 and a fair market value of $(2,574,100) and for the purchase of 580,000 Mmbtu of natural gas with a weighted average price of $4.90 Mmbtu resulting in a total contract amount of $2,402,300 and a fair market value of $397,400. The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 22 months. Open option contracts maturing in the next twelve months are for the sale of 360,000 Mmbtu with a weighted average floor price of $4.75 Mmbtu and a fair value of $0 and 180,000 Mmbtu with a weighted average ceiling price of $6.74 Mmbtu and a fair value of $0. As of March 31, 2003, RNG had entered into a series of natural gas future contracts stemming from its marketing activities. Open future contracts as of March 31, 2003 were for the sale of 4,520,000 MMBtu of natural gas with a weighted average price of $4.30 Mmbtu resulting in a total contract amount of $19,458,400 and a fair market value of $(2,873,500).

As of March 31, 2004, PDC had entered into a series of natural gas future contracts and option contracts stemming from its natural gas production. Open future contracts maturing in the next twelve months are for the purchase of 34,400 Mmbtu of natural gas with a weighted average price of $4.69 resulting in a total contract amount of $160,700 and a fair value of $44,500. Total open options contracts are for sale of 4,643,900 Mmbtu of natural gas with a weighted average floor price of $4.24 Mmbtu and a fair market value of $0 and for the purchase of 1,681,100 Mmbtu of natural gas with a weighted average ceiling price of $5.11 Mmbtu and a fair market value of ($529,500). Open option contracts maturing in the next twelve months are for the sale of 2,816,900 Mmbtu with a weighted average floor price of $4.30 Mmbtu and a fair value of $0 and 2,117,600 Mmbtu with a weighted average ceiling price of $4.98 Mmbtu and a fair value of $(260,600). The maximum term over which PDC is hedging exposure to variability of cash flows for commodity price risk is 19 months. As of March 31, 2003, PDC had entered into a series of natural gas future contracts and option contracts stemming from its natural gas production. Open future contracts as of March 31, 2003 were for the sale of 170,100 Mmbtu of natural gas with a weighted average price of $4.86 Mmbtu resulting in a total contract amount of $826,300 and a fair market value of $(51,000). Open option contracts as of March 31, 2003 were for the sale of 3,424,000 Mmbtu with a weighted average floor price of $3.88 Mmbtu and a fair value of 451,800 and 1,704,000 Mmbtu with a weighted average ceiling price of $4.86 Mmbtu and a fair value of $(994,400).

As of March 31, 2004, PDC had total open oil future contracts on 88,600 barrels of oil with a total contract amount of $2,801,200 and a fair value of $(236,600). All of the oil future contracts mature within the next twelve 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) |
|---|---|---|---|---|
| March 1 - March 31, 2004 | 48,650 | $26.61 | - | - |
| Total | 48,650 | $26.61 | - | - |

(1) On March 29, 2004 the Company purchased 48,650 shares from one of the Company's officers following the exercise by that officer of non-qualified options. The Company paid fair market value of the shares. The Compensation Committee of the Board of Directors approved the purchase.

(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 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 Certifications by Chief Executive Officer | 32.1 | Filed herewith. |
| Section 1350 Certifications by Chief Financial Officer | 32.2 | Filed herewith. |

(b) Reports on Form 8-K during the quarter ended March 31, 2004.

Form 8-K current report dated January 5, 2004, under Item 5, “Other Matters” the Company filed various employment agreements that have been executed by the Company for Messrs. Darwin L. Stump, the CFO, Thomas E. Riley, the Executive Vice President of Production, Natural Gas Marketing and Business Development and Eric R. Stearns, the Executive Vice President of Exploration and Development.

Form 8-K current report dated January 9, 2004, under Item 5, “Other Matters” the Company issued a news release announcing it has added to previously announced natural gas commodities options positions or to protect against possible price instability in future months.

Form 8-K current report dated January 13, 2004, Item 5, “Other Matters” the Company issued a news release announcing the Appointment of Steven R. Williams as CEO and Chairman of the Board.

Form 8-K current report dated February 5, 2004, Item 5, “Other Matters” the Company issued a news release announcing the purchase of additional wells in Colorado.

Form 8-K current report dated February 26, 2004, Item 5, “Other Matters” the Company issued a news release announcing plans to release fourth quarter earnings on February 27, 2004 and announcing a conference call and web cast for March 3, 2004.

Form 8-K current report dated February 27, 2004, Item 5, “Other Matters” the Company issued a news release announcing additions to natural gas and oil commodities option positions to protect against possible price instability.

Form 8-K current report dated March 1, 2004, Item 5, “Other Matters” the Company issued a news release announcing financial and operating results for the fourth quarter and full year of 2003.

Form 8-K current report dated March 15, 2004, Item 5, “Other Matters” Petroleum Development Corporation announced that it has completed the blue-sky process for the 2004 PDC Drilling program and that the program was thereupon available for sale in all 50 states and the District of Columbia.

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 5, 2004

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

Date: May 5, 2004

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