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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT
PURSUANT TO SECTIONS 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2005

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______ to ________

Commission File Number 0-7246

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

| | |
|---|---|
| Nevada | 95-2636730 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

103 East Main Street, Bridgeport, West Virginia 26330
(Address of principal executive offices) (zip code)

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

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT: NONE

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Petroleum Development Corporation Common Stock, $.01 par value
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes __ No _X_

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No _X_

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 and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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

Large Accelerated Filer [ ] Accelerated Filer [ X ] Non-Accelerated Filer [ ]

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

As of May 5, 2006, 16,057,065 shares of the Registrant's Common Stock were issued and outstanding, and the aggregate market value of such shares held by non-affiliates of the Registrant on June 30, 2005, the last business day of the Registrant's most recently completed second quarter was $518,136,692 (based on the last traded price of $31.85).

DOCUMENTS INCORPORATED BY REFERENCE

| Document | Form 10-K Part III |
|---|---|
| Proxy | Items 10, 11, 12, and 13<br>(except as presented herein) |

EXPLANATORY NOTE REGARDING RESTATEMENT

In this Annual Report on Form 10-K for the year ended December 31, 2005, the Company is amending and restating its prior consolidated statements of income for the years ended December 31, 2004 and 2003, and for each of the quarters ended in the years 2004 and 2003. The restatement also affected periods prior to 2003, those restated numbers are included in "Item 6. Selected Financial Data". This Annual Report on Form 10-K is also amending and restating our consolidated statements of income for the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005.

As previously announced in a Form 8K as filed with the Securities and Exchange Commission on April 3, 2006, the Company identified that corrections were needed to certain revenues and expenses to properly reflect the elimination of transactions between the Company and the Company sponsored limited partnerships. The corrections resulted in elimination of revenues and expenses of equal amounts. The restatement had no effect on Net Income, Earnings per Share, Cash Flow, Proved Oil and Gas Reserves, or the Company's financial position.

For a discussion of the individual restatement adjustments, see Note 22 to the Company's consolidated financial statements in "Item 8. Financial Statements and Supplementary Data". Additionally, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." For more information on the impact of the restatement on years 2001 and 2002, see "Item 6. Selected Financial Data."

The Company did not amend its Annual Report on Form 10-K or Quarterly Reports on Form 10-Q for prior periods affected by the restatement. The financial statements and related financial information contained in the Company's previously filed reports should no longer be relied upon.

All referenced amounts in this Annual Report for prior periods and prior period comparisons reflect the balances and amounts on a restated basis.

## Item 1. Business

Petroleum Development Corporation is an independent energy company engaged primarily in the development, production and marketing of natural gas and oil. Since it began oil and gas operations in 1969, the Company has grown primarily through drilling and development activities, the acquisition of producing natural gas and oil wells and the expansion of its natural gas marketing activities. As of December 31, 2005, the Company operates approximately 2,800 wells located in the Appalachian Basin, Michigan, and the Rocky Mountain Region, with gross proved reserves of 708 billion cubic feet equivalent of natural gas ("Bcfe", based on one barrel of oil equals 6 thousand cubic feet equivalent of natural gas ("Mcfe")) of which the Company's share is 275 Bcfe. The Company's share of production for the fourth quarter of 2005 averaged 38,800 Mcfe per day.

See Glossary of Terms used in this Form 10-K on Page 61.

### Business Segments

The Company's operations are divided into four segments for management and reporting purposes. (See Note 20).

### Drilling and Development

The Company drills wells not only for itself, but also for other investor partners. When the Company drills wells for others it earns profit above the cost of the wells. The Drilling and Development segment records the payments received from others as revenue and the related costs as expenses.

Since 1984, the Company has sponsored limited partnerships formed to engage in drilling operations. The Company typically purchases a 20% to 30% ownership working interest in these drilling limited partnerships. In 2005, the Company, through two public and one private drilling partnership, raised $116 million making it one of the largest sponsors of public oil and gas partnership programs in the United States as it has been for the last several years. With the partnerships as a drilling partner, the Company has been able to expand its drilling opportunities, reduce its drilling risk through greater diversification, and to share the costs of the infrastructure necessary to support such activities.

Natural Gas Marketing

The Company's wholly-owned subsidiary, Riley Natural Gas (RNG), purchases, aggregates and resells natural gas developed by the Company and other producers. This allows the Company to diversify its operations beyond natural gas drilling and production. RNG has established relationships with many of the natural gas producers in the Appalachian Basin and has significant expertise in the natural gas end-user market. In addition, RNG has extensive experience in the use of economic hedging and derivative strategies, which the Company utilizes to help manage the financial impact on the Company and its Partnerships of changes in the price of natural gas and oil. RNG also manages the marketing of oil and gas for the Company's wells outside the Appalachian Basin, but does not market gas or oil for non-affiliated producers in those areas.

Oil and Gas Sales

Revenue from the sale of oil and natural gas from the Company's interest in oil and gas wells is reported in this segment. The Company has interests in approximately 2,800 wells ranging from a few percent to 100 percent. During 2005 approximately 12% of the Company's production was generated by Appalachian Basin wells, 12% by Michigan Basin wells and 76% by Rocky Mountain wells. As of the end of 2005, the Company's total proved reserves were located as follows: Appalachian Basin 14%, Michigan 9% and Rocky Mountain Region 77%. The majority of the Company's undeveloped reserves are in the Rocky Mountain Region and the planned drilling for 2006 will be focused in that area.

Well Operations

The Company operates almost all of the approximately 2,800 wells in which it owns an interest. When it owns less than 100 percent of the working interest in a well, it charges the other owners a competitive operating fee for operating the well. These revenues and the associated costs are reflected in the Well Operations segment.

Areas of Operations

The Company's operations are divided into three regions, the Appalachian Basin, Michigan, and the Rocky Mountain Region. The Company has conducted operations in the Appalachian Basin since its inception in 1969, in Michigan since 1997, and in the Rocky Mountain Region since 1999. The Company includes its North Dakota operations in the Rocky Mountain Region.

In all three regions the Company has historically targeted shallow (less than 10,000 feet), developmental natural gas reserves for development. In some areas of the Rocky Mountain Region, Michigan and the Appalachian Basin the wells also produce oil in conjunction with natural gas. Recently the Company has begun to drill to progressively deeper targets in the Rocky Mountain Region. In particular it has drilled several wells with depths of more than 12,000 feet and horizontal wells with a total drilled footage approaching 20,000 feet. The Company's management believes these deeper and horizontal wells offer the possibility of significantly greater reserves and production than shallow wells, although they are also more expensive to drill. In addition the probability of encountering problems when drilling a deep or horizontal well is generally greater than when drilling a shallow well. With increasing costs for and declining availability of proved developed drilling locations, the Company's management believes the additional risk associated with exploratory drilling is justified by the potential to generate additional proved locations at a significantly lower cost than would be required to purchase proved undeveloped locations.

Business Strategy

The Company's primary objective is to increase shareholder value by expanding its oil and natural gas reserves, production and revenues through a strategy that includes the following key elements:

Drill and Develop

Drilling new wells, particularly shallow, developmental natural gas wells, has been the mainstay of the Company's drilling program for a number of years. The Company drilled 242 wells in 2005, compared to 158 wells in 2004. In addition the Company seeks to maximize the value of its existing wells through a program of well recompletions and drilling in areas where attractive opportunities exist. The Company's management believes that it will be able to drill a substantial number of new wells on its current undeveloped leased properties. As of December 31, 2005, the Company had leases or other development rights to 3,000 undeveloped acres in the Michigan Basin, 10,000 undeveloped acres in the northern Appalachian Basin and 245,250 undeveloped acres in the Rocky Mountain Region. The Company also has about 67 Wattenberg Field wells (Colorado) that it plans to recomplete in 2006, including 43 of the new wells it has drilled since 1999 in the field.

To support future development activities the Company has conducted exploratory drilling in the past and has continuing exploratory drilling plans in 2006. The goal of the exploration program is to develop several significant new areas for the Company to include in its future development drilling programs.

Acquire

The Company's acquisition efforts are focused on producing properties that fit well within existing operations or in areas where the Company is establishing new operations. Preferred properties have most of their value in producing wells, behind pipe reserves or high quality proved undeveloped locations. Acquisitions have historically offered economies in management and administration, and the Company’s management believes that it can acquire and manage more producing wells without incurring substantial increases in its administrative costs.

Diversify and Focus

With operations in the Rocky Mountains, Michigan and the Appalachian Basin, the Company has proven its ability to grow through operations in geographically diverse areas. While these areas provide geographic diversification, within each area the Company has concentrated positions that lend themselves to effective development and operation. The Company plans to conduct the majority of its drilling activities in the Rocky Mountain Region during 2006, but will continue to seek additional opportunities for expansion in areas where the Company's experience and expertise can be applied successfully.

Manage Risk

The Company seeks opportunities to reduce the risks inherent in the oil and gas industry in a variety of ways. For a number of years an integral part of the Company's strategy has been to concentrate on development drilling and geographical diversification to reduce risk levels associated with natural gas and oil drilling, production and markets. Development drilling is less risky than exploratory drilling and is likely to generate cash returns more quickly. Development drilling will remain the foundation of our drilling activities in 2006. However the Company’s management believes the increasing cost of high quality development locations has made exploratory drilling more attractive. Exploratory wells have the potential of identifying new development opportunities at a significantly lower cost than the current cost of proven locations. While successful exploratory efforts could add to the Company’s future drilling opportunities at favorable costs, under the successful efforts method of accounting, exploratory dry holes are expensed at the time it is recognized that they are unproductive. This could result in greater short term expenses and a reduction in the near-term profitability of the Company.

To help offset the relatively high business risk inherent in the oil and gas industry the Company maintains a conservative financial structure. The Company’s management believes that successful natural gas marketing is essential to profitable operations in a deregulated gas market. To further this goal, the Company utilizes its marketing subsidiary, Riley Natural Gas (RNG), to manage the marketing of the Company’s oil and natural gas and its commodity derivatives. This allows the Company to maintain better control over third party risk in sales and derivative activities. The Company uses natural gas and oil derivatives to reduce the effects of volatility of energy prices.

Available Information Posted on the Company's Website

The Company's Internet address is www.petd.com. Electronic copies of the Company's annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, and amendments to those reports are available free of charge by visiting the "Financial Information" section of www.petd.com. These reports are posted as soon as reasonably practicable after they are electronically filed with the Securities and Exchange Commission. Additionally, information including the Company's press releases, current drilling program sales, Bylaws, Committee Charters, Code of Business Conduct and Ethics, Shareholder Communication Policy, Board Nomination Procedures and the Whistleblower and Qualified Legal Compliance Committee Hotline is also available at the site.

Industry Overview

Natural gas is the second largest energy source in the United States, after liquid petroleum. The estimated 21.9 Tcf of natural gas consumed in 2005 represented approximately 23% of the total energy used in the United States. Natural gas is consumed in the United States as follows: 35% by industrial end-users as feedstock for products such as plastic and fertilizer or as the energy source for producing products such as glass; 22% and 14% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; and 26% by utilities for the generation of electricity; and 3% for other users. (Source U.S. Energy Information Administration)

The Company's management believes that the market for natural gas will continue to grow in the future. Natural gas is the cleanest and most environmentally safe of the fossil fuels. Relative to other energy sources, natural gas usage and losses during transportation from source to destination are slight, averaging only about 3% of the natural gas energy. The delivery of natural gas is among the safest means of distributing energy to customers, as the natural gas transmission system is fixed and is located underground.

The deregulation of the natural gas industry and a favorable regulatory environment have resulted in end-users' ability to purchase natural gas on a competitive basis from a greater variety of sources. Increasing international demand for petroleum combined with supply constraints drove oil prices to record high levels in 2005. Continuing increases in world energy demand appear likely in 2006 and beyond. This makes natural gas more competitive in domestic markets as a replacement for oil and increases the value of domestic oil and natural gas reserves.

The Company's management believes that the foregoing factors, together with the increased availability of natural gas as a form of energy for residential, commercial and industrial uses, should increase the demand for natural gas as well as create new markets for natural gas even at prices that are high by historical standards.

Because local supplies of natural gas are inadequate to meet demand in sections of the country, areas including the West Coast and the Northeast import natural gas from producing areas via interstate natural gas pipelines. The cost of transporting natural gas from the major producing areas to markets creates a price advantage for production located closer to the consuming regions. Natural gas producers in the Appalachian Basin and Michigan benefit from proximity to the northeastern United States.

In contrast, much of the production in the Rocky Mountains is transported significant distances to end user markets. As a result the price received for gas in the Rocky Mountains is generally less than the price received in areas closer to the primary consuming areas. The Rocky Mountain Region is believed to hold substantial undeveloped natural gas resources. Recent and planned additions to pipeline capacity in the region have made the area more attractive for development. Although gas from the region will generally sell for less than gas in the Appalachian and Michigan Basins, development costs may be less.

Operations

Exploration and Development Activities

The Company's development activities focus on the identification and drilling of new productive wells, the acquisition of existing producing wells from other producers, and maximizing the value of the Company's current properties through infill drilling, recompletions, and other production enhancements.

Prospect Generation

The Company's staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. These geologists have decades of cumulative experience evaluating prospects and drilling natural gas and oil wells. They utilize results from logs, seismic data and other tools to evaluate existing wells and to predict the location of economically attractive new gas reserves. To further this process, the Company has collected and continues to collect logs, core data, production information and other raw data available from state and private agencies, other companies and individuals actively drilling in the regions being evaluated. From this information the geologists develop models of the subsurface structures and formations that are used to predict areas with prospects for economic development.

On the basis of these models, the geologists instruct the Company's land department to obtain available natural gas and oil leaseholds, farmouts and other development rights in these prospective areas. These rights are then obtained, if possible, by the Company's land department or contract landmen under the direction of the Company's land manager. In most cases, the Company pays a lease bonus and annual rental payments, converting, upon initiation of production, to a royalty on gross production revenue in return for obtaining the leases. In addition overriding royalty payments may be made to third parties in conjunction with the acquisition of drilling rights initially leased by others. As of December 31, 2005, the Company had leasehold rights to approximately 258,000 acres available for development. See "Properties--Oil and Natural Gas Leases."

Drilling Activities

When prospects have been identified and leased, the Company develops these properties by drilling wells. In 2005, the Company drilled a total of 234 development wells of which 232 were successfully completed as producing wells. Typically, the Company will act as driller-operator for these prospects, frequently selling interests in the wells to partnerships, primarily Company-sponsored partnerships, and other entities that are interested in exploration or development of the prospects. The Company retains a working interest in each well it drills.

The Company also drilled 8 exploratory wells in 2005 and plans additional exploratory wells in 2006. Currently the Company plans to retain most if not all of the working interest in the exploratory wells, since the Company partnerships focus on developmental activities and are allowed only limited participation in exploratory drilling. Five of the exploratory wells drilled in 2005 were dry. The associated costs of these dry holes were $11,115,100 and these costs were expensed in 2005. See "Financing of Company Drilling and Development Activities" And “Drilling and Development Activities Conducted for Company Sponsored Partnerships.”

Much of the work associated with drilling, completing and connecting wells, including drilling, fracturing, logging and pipeline construction is performed under the Company’s direction by subcontractors specializing in those operations, as is common in the industry. When judged advantageous, material and services used by the Company in the development process are acquired through competitive bidding by approved vendors. The Company also directly negotiates rates and costs for services and supplies when conditions indicate that such an approach is warranted. Because the prices paid to the Company by its drilling partnerships for the Company's services are frequently fixed before the wells are drilled or are determined based primarily on the well depth, the Company is subject to the risk that prices of goods or services used in the development process could increase, rendering its contracts with its investor partners less profitable or unprofitable. In addition, problems encountered in the process can substantially increase development costs, sometimes without recourse for the Company to recover its costs from its partners. To minimize these risks, the Company seeks to fix its development costs in advance of drilling when possible.

Drilling Activity

The following tables summarize the Company's development and exploratory drilling activity for the last five years. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells.

| | Development Wells Drilled | | | | | |
|---|---|---|---|---|---|---|
| | Total | | Productive | | Dry | |
| | Drilled | Net | Drilled | Net | Drilled | Net |
| 2001 | 141 | 40.00 | 135 | 37.94 | 6 | 2.06 |
| 2002 | 70 | 13.71 | 70 | 13.71 | - | - |
| 2003 | 110 | 28.51 | 110 | 28.51 | - | - |
| 2004 | 157 | 43.00 | 153 | 42.40 | 4 | 0.60 |
| 2005 | 234 | 103.40 | 232 | 102.00 | 2 | 1.40 |
| Total | 712 | 228.62 | 700 | 224.56 | 12 | 4.06 |

| | Exploratory Wells Drilled | | | | | |
|---|---|---|---|---|---|---|
| | Total | | Productive | | Dry | |
| | Drilled | Net | Drilled | Net | Drilled | Net |
| 2001 | - | - | - | - | - | - |
| 2002 | - | - | - | - | - | - |
| 2003 | 1 | 1.00 | - | - | 1 | 1 |
| 2004 | 1 | 1.00 | - | - | 1 | 1 |
| 2005 | 8 | 7.30 | 3 | 2.30 | 5 | 5.00 |
| Total | 10 | 9.30 | 3 | 2.30 | 7 | 7.00 |

Financing of Company Drilling and Development Activities

The Company conducts development drilling activities for its own account and acts as operator for other investors. When conducting activities for its own account the Company uses cash flow from operations and capital provided from its long term credit facility to fund its share of operations. The Company currently has activated $80 million of a $200 million credit facility with J.P. Morgan Chase Bank, NA and BNP Paribas (collectively "the Banks"), however the Banks have determined that the Company's current oil and gas reserves would support up to $125 million of borrowing if the need arose. As of the end of 2005 the Company had $24 million outstanding under the facility.

Drilling and Development Activities Conducted for Company Sponsored Partnerships

In addition to wells and interests in wells that it drills for itself, the Company also acts as operator for other oil and gas investors. Historically these other investors have included individuals, corporations, partnerships formed by non-affiliated parties and other investors. Currently the Company's drilling partners consist primarily of public and private partnerships sponsored by the Company. The Company makes a cash investment to purchase an interest in the drilling and development activities of each partnership.

In 1984, the Company began sponsoring private drilling limited partnerships, and, in 1989, the Company began to offer partnership interests in public drilling programs registered with the SEC. The Company's public and private partnerships had $116 million in subscriptions in 2005, $100 million in subscriptions in 2004, and $78.3 million in subscriptions in 2003. The Company invests, as its equity contribution to each drilling partnership, an additional sum approximating 22% to 32% of the aggregate subscriptions received for that particular drilling partnership and receives a 20% to 30% working interest in each partnership, respectively. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. During 2005 this contribution amounted to $29.0 million. The funds received from these programs are restricted for future drilling operations. While funds were received by the Company pursuant to drilling contracts in the years indicated, the Company recognizes revenues from drilling operations on the percentage of completion method as the wells are drilled, rather than when funds are received. Substantially all of the Company's drilling and development funds are now received from partnerships in which the Company serves as managing general partner. However, because wells produce for a number of years, the Company continues to serve as operator for a number of unaffiliated parties.

The process begins when the Company enters into a development agreement with an investor partner, pursuant to which the Company agrees to sell some or all of its rights in the property to be drilled to the partnership or other entity. The partnership or other entity thereby becomes owner of a working interest in the property.

The Company's drilling contracts with its investor partners have historically taken many different forms. Starting in 2006 the drilling agreements can be classified as a "cost plus" rate, whereby the Company receives a percentage profit in addition to the actual well costs. In the past the drilling contracts could be classified as on a "footage-based" rate, whereby the Company received drilling and completion payments based on the depth of the well. Oil and gas leases are sold to the partnership at the Company's cost. The Company may also purchase an additional working interest in the partnership properties. In its financial reporting the Company reports only its share of reserves, production, oil and gas sales and costs associated with wells in which other investors participate. The level of the Company's drilling and development activity is dependent upon the amount of subscriptions in its public drilling partnerships and investments from other partnerships or other joint venture partners. Accepting investments from third party investors and Company sponsored partnerships enables the Company to diversify its holdings, thereby reducing the risk of the Company's investments. Additionally, the Company benefits through such arrangements by its receipt of fees for its management services and/or through an increased share in the revenues produced by the developed properties. The Company's management believes that investments in drilling activities, whether through Company-sponsored partnerships or other sources, are influenced in part by the favorable treatment that such investments enjoy under the federal income tax laws. No assurance can be given that the Company will continue to have access to funds generated through these financing vehicles or that the favorable tax treatment will continue.

Purchases of Producing Properties

In addition to drilling new wells, the Company continues to pursue opportunities to purchase existing wells from other producers as well as greater ownership interests in the wells it operates. Generally, outside interests purchased include a majority interest in the wells and the right to operate the wells. Although the Company made several offers to purchase properties during 2005, other potential purchasers outbid the Company; therefore none of its offers were successful.

The Company purchased a number of small interests in its partnerships from investor partners wishing to sell their interests in 2005, 2004 and 2003.

Production

The following table shows the Company's net production in thousands of barrels (MBbl) of crude oil and in million cubic feet (Mmcf) of natural gas and the costs and weighted average selling prices of oil in barrels (Bbl) and gas in thousands of cubic feet (Mcf).

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2005 | 2004 | 2003 | 2002 | 2001 |
| Production(1): | | | | | |
| Oil(MBbl) | 439 | 381 | 289 | 227 | 195 |
| Natural Gas (Mmcf) | 11,031 | 10,372 | 8,712 | 6,462 | 6,085 |
| Equivalent Mmcf(2) | 13,665 | 12,659 | 10,449 | 7,824 | 7,255 |
| Average sales price: | | | | | |
| Oil (per Bbl)(3) | $50.56 | $38.00 | $29.43 | $24.41 | $22.53 |
| Natural gas (per Mcf)(3) | $7.29 | $5.30 | $4.58 | $2.65 | $4.08 |
| Average production cost (lifting cost) | | | | | |
| Per equivalent Mcf(4) (restated) | $1.19 | $1.12 | $0.93 | $0.76 | $0.79 |

(1) Production as shown in the table is net to the Company and is determined by multiplying the gross production volume of properties in which the Company has an interest by the percentage of the leasehold or other property interest owned by the Company.

(2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one barrel of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.

(3) The Company utilizes commodity based economic derivative instruments to hedge and manage a portion of its exposure to price volatility of its natural gas and oil sales. The above table does not include the results of derivative transactions.

(4) Production costs represent oil and gas operating expenses which include severance and ad valorem taxes as reflected in the financial statements of the Company. See Oil and Gas Production and Well Operations Costs in Management's Discussion and Analysis.

Natural Gas Sales

Natural gas produced by the Company’s well interests is generally sold under monthly contracts. Virtually all of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Company’s management believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Company sells its natural gas to industrial end-users, utilities, other gas marketers, and other wholesale gas purchasers. Three customers accounted for 15.2%, 12.9% and 10.6% respectively of the Company’s revenues from oil and gas sales (9.9%, 8.4% and 6.9% of total revenues) in 2005. Two customers accounted for 14.1% and 11.3% respectively of the Company’s revenues from oil and gas sales (8.6% and 7.0% of total revenues) in 2004. Three customers accounted for 16.4%, 17.2% and 14.2%, respectively of the Company's revenues from oil and gas sales (10.5%, 11.1% and 9.1% of total revenues) in 2003. No other single purchaser of the Company's natural gas accounted for 10% or more of the Company's total revenues during 2005, 2004, and 2003.

At December 31, 2005, natural gas produced by the Company sold at prices per Mcf ranging from $2.52 to $13.31, depending upon well location, the date of the sales contract and other factors. The weighted net average price of natural gas sold by the Company during 2005 was $7.29 per Mcf.

In general, the Company, together with its marketing subsidiary, RNG, has been and expects to continue to be able to produce and sell natural gas from its wells without significant curtailment by providing natural gas to purchasers at competitive prices. Open access transportation through the country's interstate pipeline system makes a broad range of markets accessible to the Company. Whenever feasible the Company obtains access to multiple pipelines and markets from each of its gathering systems seeking the best available market for its natural gas at any point in time.

Oil Sales

Some of the Company's wells in the Appalachian Basin, Michigan, most of the Company's wells in Wattenberg field in Colorado, and the Company's North Dakota wells produce oil in addition to natural gas. At the end of 2005 oil was about 10% of the Company's total equivalent reserves.

The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company's crude oil production is sold to purchasers at or near the Company's wells under short-term purchase contracts. One purchaser accounted for 10.5%, 7.8% and 10.9% of the Company's revenues from oil and gas sales (6.9%, 4.8% and 7.0% of total revenues) in 2005, 2004, and 2003. At December 31, 2005, oil produced by the Company sold at prices ranging from $54.40 to $57.37 per barrel, depending upon the location and quality of oil. In 2005, the weighted net average price per barrel of oil sold by the Company was $50.56.

Oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of oil spills. Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to procure and implement Spill Prevention, Control and Counter-measures (“SPCC”) plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Operations of the Company are also subject to the Federal Clean Water Act and analogous state laws relating to the control of water pollution, which laws provide varying civil and criminal penalties and liabilities for release of petroleum or its derivatives into surface waters or into the ground.

Natural Gas Marketing

The Company's natural gas marketing activities involve the purchase of natural gas from other producers and the sale of that natural gas along with natural gas produced by the Company. The Company’s management believes that in a deregulated market, successful natural gas marketing is an essential component of profitable operations. A variety of factors affect the market for natural gas, including the availability of other domestic production, natural gas imports, the availability and price of alternative fuels, the proximity and capacity of natural gas pipelines, general fluctuations in the supply and demand for natural gas and the effects of state and federal regulations on natural gas production and sales. The natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers.

RNG, a wholly owned subsidiary, is a natural gas marketing company that specializes in the purchase, aggregation and sale of natural gas production in the Company's operating areas. RNG markets natural gas produced by the Company and also purchases natural gas from other producers and resells to utilities, end users or other marketers. The employees of RNG have extensive knowledge of natural gas markets in the Company's areas of operations. Such knowledge assists the Company in maximizing its prices as it markets natural gas from Company-operated wells. The gas is marketed to natural gas utilities, pipelines and industrial and commercial customers, either directly through the Company's gathering system, or utilizing transportation services provided by regulated interstate pipeline companies.

Derivative Activities

The Company utilizes commodity based economic derivative instruments to manage a portion of the exposure to price volatility stemming from its oil and natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures and option contracts for Appalachian, Michigan and eastern Colorado production, and CIG (Colorado Interstate Gas Index)-based contracts for other Colorado production and NYMEX traded oil futures and option contracts for Colorado oil production. The Company may utilize derivatives based on other indices or markets where appropriate. The contracts economically hedge committed and anticipated natural gas purchases and sales and anticipated oil sales, generally forecasted to occur within the next two to three year period. Company policy prohibits the use of natural gas or oil futures or options for speculative purposes and permits utilization of derivatives only if there is an underlying physical position.

The Company through RNG has extensive experience with the use of cash-settled derivatives to reduce the risk and impact of natural gas price changes. These financial derivatives are used by RNG to coordinate fixed and variable priced purchases and sales, and by the Company to "lock in" fixed prices from time to time for the Company's share of production, and to establish "floors" and "ceilings" or "collars" on the possible range of the prices realized for the sale of natural gas and oil. RNG also enters into fixed-price purchases and sales contracts with counterparties. These fixed physical contracts meet the FAS 133 definition of a derivative. Both types of derivatives (i.e., the physical deals and the cash settled contracts) are carried on the balance sheet at fair value with changes in fair values recognized currently in the income statement. While derivatives can help provide price protection if spot prices drop, derivatives can also limit upside potential.

For natural gas sales not subject to fixed price contracts, the Company is subject to price fluctuations for natural gas sold in the spot market and under market index contracts. The Company continues to evaluate the potential for reducing these risks by entering into derivative transactions. In addition, the Company may also close out any portion of derivatives that may exist from time to time which may result in a realized gain or loss on that derivative transaction. The Company economically manages the price risk on only a portion of its anticipated production, so some of the production is subject to the full fluctuation of market pricing.

Well Operations

The Company currently operates approximately 1,365 wells in the Appalachian Basin, 205 wells in the Michigan Basin and 1,077 wells in the Rocky Mountain Region. The Company's ownership interest in these wells ranges from less than 1% to 100%, and, on average, the Company has an approximate 50.35% ownership interest in the wells it operates. The Company has an interest in approximately 143 non-operated wells in the Rocky Mountain Region.

The Company is paid a monthly operating fee for each well it operates for outside owners including the limited partnerships sponsored by the Company. The fee is competitive with rates charged by other operators in the area. The fee covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

Transportation

Natural gas wells are connected by pipelines to natural gas markets. Over the years, the Company has developed gathering systems in some of its areas of operations. The Company also continues to construct new trunk lines as necessary to provide for the marketing of natural gas being developed from new areas and to enhance or maintain its existing systems.

The Company is paid a transportation fee for natural gas that is moved by other shippers through these pipeline systems. In many cases the Company has been able to receive higher natural gas prices as a result of its ability to move natural gas to more attractive markets through this pipeline system, to the benefit of both the Company and its investor partners.

Governmental Regulation

The Company's business and the natural gas industry in general are heavily regulated. The availability of a ready market for natural gas production depends on several factors beyond the Company's control. These factors include regulation of natural gas production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment, control and reduce the risk to the public and workers from the drilling, completion, production and transportation of oil and natural gas, prevent waste of natural gas, protect rights to produce natural gas between owners in a common reservoir and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. In the western part of the United States the federal and state governments own a large percentage of the land and the rights to develop oil and natural gas. Recently the Company has increased its positions in these types of leases. Generally government leases are subject to additional regulations and controls not commonly seen on private leases. The Company takes the steps necessary to comply with applicable regulations both on its own behalf and as part of the services it provides to its investor partnerships. The Company’s management believes that it is in compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. The following discussion of the regulation of the United States natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which the Company's operations may be subject.

## Regulation of Oil and Natural Gas Exploration and Production

The Company's oil and natural gas operations are subject to various types of regulation at the federal, state and local levels. Prior to commencing drilling activities for a well, the Company must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. Such permits and approvals include those for the drilling of wells, and such regulation includes maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. The Company's operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore, more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. Where wells are to be drilled on state or federal leases, additional regulations and conditions may apply. The effect of these regulations may limit the amount of oil and natural gas the Company can produce from its wells and may limit the number of wells or the locations at which the Company can drill. The regulatory burden on the oil and natural gas industry increases the Company's costs of doing business and, consequently, affects its profitability. Inasmuch as such laws and regulations are frequently expanded, amended and reinterpreted, the Company is unable to predict the future cost or impact of complying with such regulations.

## Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce were regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (the "NGPA") and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC). Maximum selling prices of certain categories of natural gas sold in "first sales," whether sold in interstate or intrastate commerce, were regulated pursuant to the NGPA. The Natural Gas Wellhead Decontrol Act (the "Decontrol Act") removed, as of January 1, 1993, all remaining federal price controls from natural gas sold in "first sales" on or after that date. FERC's jurisdiction over natural gas transportation was unaffected by the Decontrol Act. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at market prices, Congress could reenact price controls in the future.

The Company's sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In the past, FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system was substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide transportation separate or "unbundled" from their sales service, and require that pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers. In many instances, the result of Order No. 636 and related initiatives has been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. Another effect of regulatory restructuring is the greater transportation access available on interstate pipelines. In some cases, producers and marketers have benefited from this availability. However, competition among suppliers has greatly increased and traditional long-term producer-pipeline contracts are rare. Furthermore, gathering facilities of interstate pipelines are no longer regulated by FERC, thus allowing gatherers to charge higher gathering rates.

Additional proposals and proceedings that might affect the natural gas industry occur frequently in the Congress, FERC, state commissions, state legislatures, and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue. The Company cannot determine to what extent future operations and earnings of the Company will be affected by new legislation, new regulations, or changes in existing regulation, at federal, state or local levels.

## Environmental Regulations

The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stricter environmental legislation and regulations could continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs and reduced access to the natural gas industry in general, the business and prospects of the Company could be adversely affected.

The Company generates wastes that may be subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by the Company's operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases numerous properties that for many years have been used for the exploration and production of oil and natural gas. Although the Company’s management believes that it has utilized good operating and waste disposal practices, prior owners and operators of these properties may not have utilized similar practices, and hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws as well as state laws governing the management of oil and natural gas wastes. Under such laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for release of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company's operations may be subject to the Clean Air Act ("CAA") and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company. The EPA and states have been developing regulations to implement these requirements. The Company may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues.

The Company's expenses relating to preserving the environment during 2005 were not significant in relation to operating costs and the Company expects no material change in 2006. Environmental regulations have had no materially adverse effect on the Company's operations to date, but no assurance can be given that environmental regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on the Company's business, financial condition or results of operations.

Operating Hazards and Insurance

The Company's exploration and production operations include a variety of operating risks, including the risk of fire, explosions, blowouts, cratering, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of toxic gas, the occurrence of any of which could result in substantial losses to the Company due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. The Company's pipeline, gathering and distribution operations are subject to the many hazards inherent in the natural gas industry. These hazards include damage to wells, pipelines and other related equipment, and surrounding properties caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any significant problems related to its facilities could adversely affect the Company's ability to conduct its operations. In accordance with customary industry practice, the Company maintains insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event not fully insured against could materially adversely affect the Company's operations and financial condition. The Company cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Competition

The Company’s management believes that its exploration, drilling and production capabilities and the experience of its management and professional staff generally enable it to compete effectively. The Company encounters competition from numerous other oil and natural gas companies, drilling and income programs and partnerships in all areas of its operations, including drilling and marketing oil and natural gas and obtaining desirable oil and natural gas leases. Many of these competitors possess larger staffs and greater financial resources than the Company, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. The Company's ability to explore for oil and natural gas prospects and to acquire additional properties in the future depends upon its ability to conduct its operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. The Company competes with a number of other companies that offer interests in drilling partnerships with a wide range of investment objectives and program structures. Competition for investment capital for both public and private drilling programs is intense. The Company also faces intense competition in the marketing of natural gas from competitors including other producers as well as marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic oil and natural gas exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future. During 2005 the industry experienced increased demand for drilling services and supplies. This is resulting in increasing costs, and in some cases the demand for supplies and services exceeds the available supplies. This can result in higher well costs and delays in the execution of planned drilling operations. Factors affecting competition in the oil and natural gas industry include price, location, availability, quality and volumes produced. The Company’s management believes that it can compete effectively in the oil and natural gas industry on each of the foregoing factors. Nevertheless, the Company's business, financial condition or results of operations could be materially adversely affected by competition.

Employees

As of December 31, 2005, the Company had 150 employees, including 21 in finance and data processing, 9 in administration, 15 in exploration and development, 99 in production and 6 in natural gas marketing. The Company's engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and pipeline systems. In addition, the Company retains subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites. The Company's employees act as supervisors of the subcontractors. The Company added 36 new employees in 2005.

The Company's employees are not covered by a collective bargaining agreement. The Company considers relations with its employees to be excellent.

Item 1A. Risks Related to the Oil and Natural Gas Industry and the Company

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

*Oil and natural gas prices fluctuate unpredictably and a decline in oil and natural gas prices can significantly affect the Company’s financial results and impede its growth.*

The Company’s revenue, profitability and cash flow depend in large part upon the prices and demand for oil and natural gas. The markets for these commodities are very volatile and even relatively modest drops in prices can significantly affect the Company’s financial results and impede its growth. Changes in oil and natural gas prices have a significant impact on the value of the Company’s reserves and on its cash flow. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond the Company’s control, including national and international economic and political factors and federal and state legislation.

Lower oil and natural gas prices may not only decrease the Company’s revenues, but also may reduce the amount of oil and natural gas that the Company can produce economically. This may result in the Company having to make substantial downward adjustments to its estimated proved reserves. If this occurs or if the Company’s estimates of development costs increase, production data factors change or the Company’s exploration results deteriorate, accounting rules may require us to write down to fair value, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which management reasonably estimates such products to be sold. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows. The Company may incur impairment charges in the future, which could have a material adverse effect on its results of operations.

*The Company’s estimated oil and gas reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of the Company’s reserves.*

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate. The Company’s estimates of oil and gas reserves are prepared by the independent petroleum engineers, using pricing, production, cost, tax and other information provided by the Company. Over time, the independent petroleum engineers may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. The reserve estimates are based on certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect the estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, future depreciation, depletion and amortization rates and amounts, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Some of our reserve estimates are made without the benefit of a lengthy production history, which renders these reserve estimates less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which the reserve estimates are based, as described above, often result in the actual quantities of oil and gas recovered being different from earlier reserve estimates.

The present value of future net cash flows from the proved reserves is not necessarily the same as the current market value of the estimated oil and natural gas reserves (the Securities and Exchange Commission requires the use of year end prices). The estimated discounted future net cash flows from proved reserves are based on selling prices in effect on the day of estimate (year end) and future estimated costs. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as actual prices we receive for oil and natural gas, the amount and timing of actual production, amount and timing of future development costs, supply of and demand for oil and natural gas, and changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor (rate required by the Securities and Exchange Commission) we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our oil and gas properties or the oil and natural gas industry in general.

*Unless oil and natural gas reserves are replaced as they are produced, the Company’s reserves and production will decline, which would adversely affect the Company’s business, financial condition and results of operations.*

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we have estimated and can change due to other circumstances. Thus, the Company’s future oil and natural gas reserves and production and, therefore, its cash flow and income are highly dependent on efficiently developing and exploiting the Company’s current reserves and economically finding or acquiring additional recoverable reserves. The Company may not be able to develop, discover or acquire additional reserves to replace our current and future production at acceptable costs. As a result, the Company's operations, financial condition and results of operations would be adversely affected.

*Prospects drilled by the Company may not yield natural gas or oil in commercially viable quantities.*

A prospect is a property on which the Company's geologists have identified what they believe, based on available information, to be indications of natural gas or oil bearing rocks. However, the use of available data and other technologies and the study of producing fields in the same area will not enable the geologists to know conclusively prior to drilling and testing whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in sufficient quantities to repay drilling or completion costs and generate a profit. If a well is determined to be dry or uneconomic, which can occur even though it contains some oil or gas, it is classified as a dry hole and must be plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point, the cost of plugging, and lease costs associated with the prospect. Even wells that are completed and placed into production may not produce sufficient oil and gas to be profitable. If the Company drills a dry hole or non-profitable well on current and future prospects, the profitability of its operations will decline and the value of the Company will be reduced. In sum, the cost of drilling, completing and operating any well is often uncertain and new wells may not be productive.

*The Company may not be able to identify enough attractive prospects on a timely basis to meet its own development needs and those of the partnerships it forms for investors, which could limit the Company's development opportunities and/or force it to reduce the partnership activity.*

Our geologists have identified a number of potential drilling locations on our existing acreage. These drilling locations must be replaced as they are drilled for the Company to continue to grow its reserves and production, and for it to be able to continue its partnership drilling activities. The Company's ability to identify and acquire new drilling locations depends on a number of uncertainties, including the availability of capital, regulatory approvals, oil and natural gas prices, competition, costs, drilling results, and the ability of the Company's geologists to successfully identify potentially successful new areas to develop. Because of these uncertainties, the Company's profitability and growth opportunities may be limited by the timely availability of new drilling locations, and it could be forced to terminate or curtail its partnership activities because of a lack of suitable prospects for the partnerships. As a result, the Company's operations and profitability would be adversely affected.

*Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect the Company's business, financial condition and results of operations.*

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including unusual or unexpected geological formations, pressures, fires, blowouts, loss of drilling fluid circulation, title problems, facility or equipment malfunctions, unexpected operational events, shortages or delivery delays of equipment and services, compliance with environmental and other governmental requirements, and adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and regulatory penalties. The Company maintains insurance against various losses and liabilities arising from operations; however, insurance against all operational risks is not available. Additionally, the Company management may elect not to obtain insurance if the cost of available insurance is excessive relative to the perceived risks presented. Thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on the Company's business activities, financial condition and results of operations.

*Increased drilling activity, particularly in the Rocky Mountain Region, may create a shortage of drilling rigs, service providers, or materials forcing the Company to curtail its drilling operations for itself and its partnerships thereby reducing revenue and profits from new oil and gas wells and from the Company's drilling and completion activities.*

With high levels of oil and gas prices many oil and gas companies have increased their levels of drilling and completing new wells and reworking old wells. At the same time there is a limited supply of drilling rigs, completion equipment and qualified personnel to provide the services necessary to drill, complete and rework new wells. In particular, the Rocky Mountain Region has seen a great increase in activity over the past few years. If the demand for these goods and services continues to increase shortages may develop, which could result in increased prices for these goods and services or the Company's inability to complete all of the drilling it has planned. This could result in less drilling by the Company and the temporary or permanent loss of part or all of its partnership drilling activity and less profitability for the Company.

*The Company's drilling and development segment receives virtually all of its revenue from the partnerships it sponsors, and a reduction or loss of that business could reduce or eliminate the revenue and profits associated with those activities.*

The Company's drilling activities are dependent upon the capital raised by the Company as a sponsor of limited partnerships. The Company sells oil and natural gas partnerships through a network of non-affiliated NASD broker dealers. The largest of those broker dealers sold about 13.8% of the partnership units in 2005. Investors in the partnerships are interested in the tax deductions generated by the intangible drilling costs and the cash flow generated by the partnerships. If the tax laws were changed to reduce or eliminate the tax advantages, if the cash flow from the partnerships were to decline due to weak wells or lower energy prices, or if the brokers decide to stop offering our partnerships for some reason, the sales of the partnership units would decline, reducing or eliminating the revenue and profits associated with the drilling and development business segment. As a result, the Company's operations and profitability would be adversely affected.

*Under the Successful Efforts accounting method used by the Company unsuccessful exploratory wells must be expensed in the period when they are determined to be non-productive which results in a reduction of the Company's net income and profitability and could have a negative impact on the Company's stock price.*

The Company increased its exploratory drilling in 2005 and plans to further increase its exploratory drilling in 2006 in order to identify additional opportunities for future development. However the cost of unsuccessful exploratory wells must be charged to expense in the period when they are determined to be unsuccessful under the successful efforts method of accounting used by the Company. In addition lease costs for acreage condemned by the unsuccessful well must also be expensed. In contrast unsuccessful development wells are capitalized as a part of the investment in the field where they are located. Because exploratory wells generally are more likely to be unsuccessful than development wells, the Company anticipates that some or all of its exploratory wells may not be productive. The costs of such unsuccessful wells could result in a significant reduction in the Company's profitability in periods when the costs are required to be expensed, which could have an adverse effect on the Company's stock price. In addition unsuccessful wells will not add to the Company's reserves or production.

*We may incur substantial impairment write-downs, due to revisions in our estimates of our reserves, if development costs exceed estimates or if price of oil and natural gas declines.*

If management's estimate of the recoverable reserves on a property is revised downward, if development costs exceed previous estimates or if oil and natural gas prices decline, we may be required to record additional non-cash impairment writedowns in the future, which would result in a negative impact to our financial position. We review our proved oil and gas properties for impairment on a quarterly basis. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reserve engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis. Fair value is estimated to be the present value of the aforementioned expected future net cash flows. Any impairment charge incurred is recorded as a reduction to the asset value. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value. There were no impairments during 2005, 2004 or 2003.

*Rising finding and development costs may impair our profitability.*

In order to continue to grow and maintain its profitability, the Company must annually add new reserves exceeding its yearly production at a finding and development cost that yields an acceptable operating margin and depreciation, depletion and amortization rate. Without cost effective exploration, development or acquisition activities, production, reserves and profitability will decline over time. Given the relative maturity of most gas basins in North America the cost of finding new reserves through exploration and development operations has been increasing. The acquisition market for natural gas properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values climbed toward historic highs during 2005 on a per unit basis, particularly in the Rocky Mountain Region, and the Company believes these values may continue to increase in 2006. This increase in finding and development costs is resulting in higher depreciation, depletion and amortization rates. If the upward trend in finding and development costs continues, the Company will be exposed to an increased likelihood of a write-down in carrying value of its natural gas and oil properties in response to falling prices, which would impair its profitability.

*The Company's development and exploration operations require substantial capital and it may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves and production.*

The oil and natural gas industry is capital intensive. The Company makes and expects to continue to make substantial capital expenditures in its business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, the Company has financed capital expenditures primarily with cash generated by operations, limited partnership offerings and proceeds from bank borrowings. Currently the Company intends to finance its capital expenditures with cash flows from operations, and its existing financing arrangements. Cash flows from operations and access to capital are subject to a number of variables, including the Company's proved reserves, the level of oil and natural gas the Company is able to produce from existing wells, the prices at which oil and natural gas are sold, and the Company's ability to acquire, locate and produce new reserves.

If the Company's revenues or the borrowing base under its revolving credit facility decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, it may have limited ability to obtain the capital necessary to sustain its operations at planned levels.

If additional capital is needed, the Company may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by operations or sale of limited partnerships or available under our revolving credit facility is not sufficient to meet our capital requirements, failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves and a decline in our profitability.

*The Company's credit facility and other debt financing have substantial restrictions and financial covenants and the Company may have difficulty obtaining additional credit, which could adversely affect our operations.*

The Company will depend on its revolving credit facility for future capital needs. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flows from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility or other debt financing could result in a default under those facilities, which could cause all of our existing indebtedness to be immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion, based upon projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility. Our inability to borrow additional funds under our credit facility could adversely affect our operations.

*A substantial part of the Company's producing properties is located in the Rocky Mountains, making it vulnerable to risks associated with operating in one major geographic area.*

The Company's operations are becoming increasingly focused on the Rocky Mountain Region, which means its producing properties and new drilling opportunities are geographically concentrated in that area. As a result, the Company, the success of its operations, and its profitability may be disproportionately exposed to the impact of delays or interruptions of production from existing or planned new wells by significant governmental regulation, transportation capacity constraints, curtailment of production, interruption of transportation, or fluctuations in prices of oil and natural gas produced from the wells in the region.

*Seasonal weather conditions and lease stipulations adversely affect the Company's ability to conduct drilling activities in some of the areas where we operate.*

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, including parts of the Sand Wash and Piceance Basins in Colorado, drilling and other oil and natural gas activities are restricted or prohibited by lease stipulations, or prevented by weather conditions, for up to 6 months out of the year. This limits operations in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay operations and materially increase operating and capital costs and therefore adversely affect profitability.

*Properties that the Company buys may not produce as projected and the Company may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.*

One of the Company's growth strategies is to acquire producing oil and natural gas reserves in its areas of operations and in new areas to help establish a base of operations for further development. However, reviews of potential acquisitions are inherently incomplete because it generally is not feasible to review in depth every individual property. Ordinarily, the Company focuses review efforts on the higher value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable or detectable even when an inspection is undertaken. Even when problems are identified, the Company may choose to assume certain environmental and other risks and liabilities in connection with acquired properties.

*We have limited control over activities on properties we do not operate, which could reduce our production and revenues.*

The Company operates most of the wells in which it owns an interest. However there are some wells the Company does not operate because it participates through joint operating agreements under which it owns partial interests in oil and natural gas properties operated by other entities. If the Company does not operate the properties in which it owns an interest, it does not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator to adequately perform operations, or an operator's breach of the applicable agreements, could reduce production and revenues and affect our profitability. The success and timing of drilling and development activities on properties operated by others therefore depends upon a number of factors outside of the Company's control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology.

*Market conditions or operational impediments hinder access to oil and natural gas markets or delay production.*

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder access to oil and natural gas markets or delay production. The availability of a ready market for oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. The Company's ability to market its production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Failure to obtain such services on acceptable terms could materially harm the Company's business. We may be required to shut in wells for lack of market or because of inadequacy or unavailability of natural gas pipeline, gathering system capacity or processing facilities. If that were to occur, the Company would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market and its profitability would be adversely affected.

*Our derivative activities could result in financial losses or could reduce our income.*

To achieve a more predictable cash flow, to reduce exposure to adverse fluctuations in the prices of oil and natural gas and to allow our gas marketing company to offer pricing options to gas sellers and purchasers, the Company uses derivatives for a portion of its oil and natural gas production from its own wells, and for gas purchases and sales by its marketing subsidiary. These arrangements expose the Company to the risk of financial loss in some circumstances, including when production, purchases or sales are different than expected, the counter-party to the derivative contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the derivative agreement and actual prices received. In addition, derivative hedging arrangements may limit the benefit from changes in the prices for oil and natural gas and may require the use of Company resources to meet cash margin requirements. Since the Company does not use hedge accounting treatment for their derivatives, its earnings are subject to greater volatility.

*The inability of one or more of our customers to meet their obligations may adversely affect our financial results.*

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, the Company's oil and natural gas derivatives as well as the derivatives used by its marketing subsidiary expose the Company to credit risk in the event of nonperformance by counterparties.

*The Company depends on a limited number of key personnel who would be difficult to replace.*

The Company depends on the performance of our executive officers and other key employees. The loss of any member of senior management or other key employees could negatively impact the Company's ability to execute its strategy. The Company does not maintain key person life insurance policies on any of its employees.

*Terrorist attacks or similar hostilities may adversely impact our results of operations.*

The terrorist attacks that took place in the United States on September 11, 2001 were unprecedented events that have created many economic and political uncertainties, some of which may materially adversely impact our business. Uncertainty surrounding military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. The continuation of these developments may subject our operations to increased risks and depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations, financial condition and prospects.

*Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.*

The occurrence of a significant accident or other event not fully covered by our insurance could have a material adverse effect on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable.

*We may not be able to keep pace with technological developments in our industry.*

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other natural gas and oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

*Competition in the oil and natural gas industry is intense, which may adversely affect the Company's ability to succeed.*

The oil and natural gas industry is intensely competitive, and the Company competes with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than the Company can, which would adversely affect the Company's competitive position. The Company's ability to acquire additional properties and to discover reserves in the future will be dependent upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because many companies in our industry have greater financial and human resources, the Company may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. These factors could adversely affect the success of the Company's operations and its profitability.

*The Company is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.*

The Company's exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, the Company could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject the Company to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, the Company's activities are subject to the regulation by oil and natural gas-producing states of conservation practices and protection of correlative rights. These regulations affect operations and limit the quantity of oil and natural gas that can be produced and sold. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals, drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on the Company's ability to explore on or develop its properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect profitability. Furthermore, the Company may be put at a competitive disadvantage to larger companies in the industry who can spread these additional costs over a greater number of wells and larger operating staff. See "Business — Governmental Regulation — Regulation of Oil and Natural Gas Exploration and Production" and "Business — Governmental Regulation — Environmental Regulations" for a description of the laws and regulations that affect us.

Item 2. Properties

Summary of Productive Wells

The table below shows the number of the Company's productive gross and net wells at December 31, 2005.

| | Productive Wells | | | |
|---|---|---|---|---|
| | Gas | | Oil | |
| Location | Gross | Net | Gross | Net |
| Colorado | 1,187 | 644.34 | 4 | 0.79 |
| Kansas | 25 | 22.00 | - | - |
| Michigan | 198 | 110.17 | 7 | 2.66 |
| North Dakota | - | - | 4 | 2.50 |
| Pennsylvania | 420 | 92.21 | - | - |
| Tennessee | 1 | 0.71 | 35 | 13.73 |
| West Virginia | 905 | 514.01 | 4 | 1.72 |
| Total | 2,736 | 1,383.44 | 54 | 21.40 |

Oil and Gas Reserves

All of the Company's oil and natural gas reserves are located in the United States. The Company's approximate net proved reserves were estimated by independent petroleum engineers, to be 247,288,000 Mcf of natural gas and 4,538,000 Bbls of oil at December 31, 2005, 197,549,000 Mcf of natural gas and 3,316,000 Bbls of oil at December 31, 2004, and 180,998,000 Mcf of natural gas and 3,029,000 Bbls of oil at December 31, 2003.

The Company's approximate net proved developed reserves were estimated, by independent petroleum engineers, to be 155,354,000 Mcf of natural gas and 3,860,000 Bbls of oil at December 31, 2005, 146,152,000 Mcf of natural gas and 3,190,000 Bbls of oil at December 31, 2004, and 134,936,000 Mcf of natural gas and 2,889,000 Bbls of oil at December 31, 2003.

The Company utilized the services of two independent petroleum engineers for its 2005 independent reserve report. Wright & Company prepared the reserve report for the Appalachian and Michigan Basins and Colorado wells. Ryder Scott Company, LLP prepared the reserve report for the North Dakota Bakken Shale wells. Wright & Company prepared all of the reserve reports for the Company for 2004 and 2003.

The Company's oil and natural gas reserves by region are as follows as of December 31, 2005:

| | Oil (Mbbl) | Gas (Mmcf) | Natural Gas Equivalent (Mmcfe) | % |
|---|---|---|---|---|
| Proved Developed Reserves | | | | |
| Appalachian Basin | 42 | 37,843 | 38,095 | 21.34 |
| Michigan Basin | 53 | 25,094 | 25,412 | 14.24 |
| Rocky Mountain Region | 3,765 | 92,417 | 115,007 | 64.42 |
| Total Proved Developed Reserves | 3,860 | 155,354 | 178,514 | 100.00 |
| Proved Undeveloped Reserves | | | | |
| Appalachian Basin | - | - | - | - |
| Michigan Basin | - | 544 | 544 | 0.57 |
| Rocky Mountain Region | 678 | 91,390 | 95,458 | 99.43 |
| Total Proved Undeveloped | 678 | 91,934 | 96,002 | 100.00 |
| Total Proved Reserves | | | | |
| Appalachian Basin | 42 | 37,843 | 38,095 | 13.88 |
| Michigan Basin | 53 | 25,638 | 25,956 | 9.46 |
| Rocky Mountain Region | 4,443 | 183,807 | 210,465 | 76.66 |
| Total Proved Reserves | 4,538 | 247,288 | 274,516 | 100.00 |

No major discovery or other favorable or adverse event that would cause a significant change in estimated reserves is believed by the Company to have occurred since December 31, 2005. Reserves cannot be measured exactly, because reserve estimates involve subjective judgment. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes.

The standardized measure of discounted future estimated net cash flows attributable to the Company's proved oil and gas reserves, giving effect to future estimated income tax expenses, was estimated by our independent petroleum engineers to be $405.4 million as of December 31, 2005, $229.4 million as of December 31, 2004, and $202.4 million as of December 31, 2003. These amounts are based on December 31 prices in the respective years. The values expressed are estimates only, and may not reflect realizable values or fair market values of the natural gas and oil ultimately extracted and recovered. The standardized measure of discounted future net cash flows may not accurately reflect proceeds of production to be received in the future from the sale of natural gas and oil currently owned and does not necessarily reflect the actual costs that would be incurred to acquire equivalent natural gas and oil reserves.

Net Proved Natural Gas and Oil Reserves

The proved reserves of natural gas and oil of the Company as estimated by our independent petroleum engineers at December 31, 2005 are set forth below. These reserves have been prepared in compliance with the rules of the Securities and Exchange Commission (the "SEC") based on December 31, 2005 prices. These reserve estimates were not filed with another Federal authority or agency since the Company filed its Form 10-K/A as of December 31, 2004. An analysis of the change in estimated quantities of natural gas and oil reserves from January 1, 2005 to December 31, 2005, all of which are located within the United States, is shown below:

| | Natural Gas (Mcf) | Oil (Bbl) |
|---|---|---|
| Proved developed and undeveloped reserves: | | |
| Beginning of year | 197,549,000 | 3,316,000 |
| Revisions of previous estimates | (15,850,000) | 80,000 |
| Beginning of year as revised | 181,699,000 | 3,396,000 |
| New discoveries and extensions | | |
| Rocky Mountain region | 85,624,000 | 1,576,000 |
| Dispositions to partnerships | (9,556,000) | - |
| Acquisitions | | |
| Michigan Basin | 47,000 | - |
| Rocky Mountain region | 71,000 | 5,000 |
| Appalachian basin | 434,000 | - |
| Production | (11,031,000) | (439,000) |
| End of year | 247,288,000 | 4,538,000 |
| Proved developed reserves: | | |
| Beginning of year | 146,152,000 | 3,190,000 |
| End of year | 155,354,000 | 3,860,000 |

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Natural Gas and Oil Reserves

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves. Future cash inflows are computed by applying year-end prices of natural gas and oil relating to the Company's proved reserves to year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs, assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at December 31, 2005 to the future pretax net cash flows, less the tax basis of the properties, and gives effect to permanent differences, tax credits and allowances related to the properties.

| | |
|---|---|
| Future Estimated Cash Flows | $ 2,381,238,000 |
| Future Estimated Production Costs | (545,683,000) |
| Future Estimated Development Costs | (207,164,000) |
| Future Estimated Income Tax Expense | (633,444,000) |
| Future Net Cash Flows | 994,947,000 |
| 10% Annual Discount for Estimated Timing of Cash Flows | (589,517,000) |
| Standardized Measure of Discounted Future Estimated Net Cash Flows | $ 405,430,000 |

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows from January 1, 2005 through December 31, 2005:

| | 2005 |
|---|---|
| Sales of oil and gas production net of production costs | $ (86,366,000) |
| Net changes in prices and production costs | 208,353,000 |
| Extensions, discoveries, and improved recovery, less related costs | 150,654,000 |
| Sales of reserves | (14,456,000) |
| Purchase of reserves | 1,266,000 |
| Development costs incurred during the period | 24,035,000 |
| Revisions of previous quantity estimates | (24,130,000) |
| Changes in estimated income taxes | (112,054,000) |
| Accretion of discount | 38,241,000 |
| Timing and other | (9,541,000) |
| Total | $ 176,002,000 |

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves, because the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision, and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods and their inherent limitations.

Substantially all of the Company's natural gas and oil reserves have been mortgaged or pledged as security for the Company's credit agreement. See Note 3 to the notes to the Company's financial statements.

Oil and Natural Gas Leases

The following table sets forth, as of December 31, 2005, the acres available for development of oil and natural gas available to the Company, listed alphabetically by state.

| | |
|---|---|
| Colorado | 115,200 |
| Kansas | 22,800 |
| Michigan | 3,000 |
| New York | 10,000 |
| North Dakota | 80,000 |
| Wyoming | 27,250 |
| Total | 258,250 |

Title to Properties

The Company’s management believes that it holds good and indefeasible title to its properties, in accordance with standards generally accepted in the natural gas industry, subject to such exceptions stated in the opinion of counsel employed in the various areas in which the Company conducts its exploration activities. Those exceptions, in the Company's judgment, do not detract substantially from the use of such property. As is customary in the natural gas industry, only a perfunctory title examination is conducted at the time the properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, an extensive title examination is conducted and curative work is performed with respect to defects which the Company deems to be significant. A title examination has been performed with respect to substantially all of the Company's producing properties. No single property owned by the Company represents a material portion of the Company's holdings.

The properties owned by the Company are subject to royalty, overriding royalty and other outstanding interests customary in the industry. The properties are also subject to burdens such as liens incident to operating agreements, current taxes, development obligations under natural gas and oil leases, farm-out arrangements and other encumbrances, easements and restrictions. The Company does not believe that any of these burdens will materially interfere with the use of the properties.

Facilities

The Company owns and occupies three buildings in Bridgeport, West Virginia, two of which serve as the Company's headquarters and one that serves as a field operating facility. The Company is currently building a new corporate office in Bridgeport, WV which it will occupy in late 2006. The Company also owns a field operating building in Weld County, Colorado and Gilmer County, West Virginia. The Company has operating leases for field offices in Colorado, Michigan and Pennsylvania.

## Item 3. Legal Proceedings

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

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

No matters were submitted to a vote of security holders during the fourth quarter of the fiscal year covered by this report.

# PART II

## Item 5. Market for the Registrant's Common Equity and Related Stockholders Matters and Issuer Purchases of Equity Securities.

The common stock of the Company is traded in the NASDAQ National Market under the symbol PETD. The following table sets forth, for the periods indicated, the high and low bid quotations per share of the Company's common stock in the over-the-counter market, as reported by NASDAQ. These quotations represent inter-dealer prices without retail markups, markdowns, commissions or other adjustments and may not represent actual transactions.

| | High | Low |
|---|---|---|
| 2005 | | |
| First Quarter | $44.19 | $35.72 |
| Second Quarter | 37.28 | 22.65 |
| Third Quarter | 40.00 | 32.54 |
| Fourth Quarter | 39.55 | 30.53 |
| 2004 | | |
| First Quarter | 33.93 | 16.70 |
| Second Quarter | 32.63 | 21.01 |
| Third Quarter | 44.80 | 24.50 |
| Fourth Quarter | 49.26 | 32.06 |

As of May 11, 2006, there were approximately 874 record holders of the Company's common stock.

The Company has not paid any dividends on its common stock and currently intends to retain earnings for use in its business. Therefore, it does not expect to declare cash dividends in the foreseeable future. Further, the Company's Credit Agreement restricts the payment of dividends.

Item 6. Selected Financial Data

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2005 | 2004 (1) | 2003 (1) | 2002 (2) | 2001 (2) |
| | | (Restated) | (Restated) | (Restated) | (Restated) |
| Revenues: | | | | | |
| Oil and gas well drilling operations | $ 99,962,900 | $ 94,076,000 | $ 57,509,600 | $ 45,842,000 | $ 60,756,300 |
| Gas sales from marketing activities | 121,104,100 | 94,626,800 | 73,131,700 | 43,536,400 | 67,070,900 |
| Oil and gas sales | 102,559,200 | 69,492,100 | 48,393,800 | 22,688,100 | 29,199,100 |
| Well operations and pipeline income | 8,759,600 | 7,676,900 | 6,907,100 | 5,771,200 | 5,349,200 |
| Other income | 10,747,300 | 1,880,700 | 3,528,500 | 2,796,800 | 3,132,400 |
| Total revenues | 343,133,100 | 267,752,500 | 189,470,700 | 120,634,500 | 165,507,900 |
| Costs and expenses: | | | | | |
| Cost of oil and gas well drilling operations | 88,184,900 | 77,696,200 | 46,945,900 | 37,859,100 | 50,465,000 |
| Cost of gas marketing activities | 119,643,700 | 92,881,200 | 72,361,400 | 43,167,700 | 66,545,100 |
| Oil and gas production and well operations costs | 19,934,700 | 17,277,200 | 13,251,300 | 8,672,400 | 8,327,700 |
| Exploratory dry hole costs | 11,115,100 | - | - | - | - |
| General and administrative expenses | 6,960,300 | 4,505,600 | 4,974,400 | 4,391,900 | 4,145,700 |
| Depreciation, depletion and amortization | 21,116,200 | 18,155,900 | 15,312,800 | 12,601,500 | 11,582,100 |
| Impairment of oil and gas properties | - | - | - | - | 10,541,900 |
| Total costs and expenses | 266,954,900 | 210,516,100 | 152,845,800 | 106,692,600 | 151,607,500 |
| Income from operations | 76,178,200 | 57,236,400 | 36,624,900 | 13,941,900 | 13,900,400 |
| Interest expense | 682,300 | 673,700 | 1,195,300 | 1,504,800 | 1,898,700 |
| Oil and gas price risk management loss, net | 9,368,100 | 3,084,600 | 812,400 | 369,800 | 3,311,200 |
| Income before income taxes and cumulative effect of change in accounting principle | 66,127,800 | 53,478,100 | 34,617,200 | 12,067,300 | 8,690,500 |
| Income taxes | 24,676,100 | 20,250,500 | 11,933,500 | 3,186,200 | 1,803,100 |
| Net income before cumulative effect of change in accounting principle | 41,451,700 | 33,227,600 | 22,683,700 | 8,881,100 | 6,887,400 |
| Cumulative effect of change in accounting principle (net of taxes of $1,392,000) | - | - | (2,271,300) | - | - |
| Net income | $ 41,451,700 | $ 33,227,600 | $ 20,412,400 | $ 8,881,100 | $ 6,887,400 |
| Basic earnings per common share | $2.53 | $2.05 | $1.30 | $0.56 | $0.42 |
| Diluted earnings per share | $2.52 | $2.00 | $1.25 | $0.55 | $0.41 |

| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2005 | 2004 | 2003 | 2002 | 2001 |
| Total Assets | $ 449,084,900 | $ 335,028,300 | $ 297,541,600 | $ 201,022,200 | $ 186,255,700 |
| Working Capital (Deficit) | $ (25,831,200) | $ 231,100 | $ 7,287,800 | $ 3,173,300 | $ 3,310,800 |
| Long-Term Debt | $ 24,000,000 | $ 21,000,000 | $ 53,000,000 | $ 25,000,000 | $ 28,000,000 |
| Stockholders' Equity | $ 188,265,300 | $ 154,020,600 | $ 112,559,200 | $ 92,886,600 | $ 87,616,300 |

(1) See Note 22 on page F-36 for the effect of the restatement on the above data.
(2) See Explanatory Note regarding restatement on Page 2.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

Statements, other than historical facts, contained in this Annual Report on Form 10-K, including statements of estimated oil and gas production and reserves, drilling plans, future cash flows, anticipated capital expenditures and Management's strategies, plans and objectives, are "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company’s management believes that its forward looking statements are based on reasonable assumptions, it cautions that such statements are subject to a wide range of risks and uncertainties incidental to the exploration for, acquisition, development and marketing of oil and gas, and it can give no assurance that its estimates and expectations will be realized. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to, changes in production volumes, worldwide demand, and commodity prices for petroleum natural resources; the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and gas reserves; the Company's ability to acquire leases, drilling rigs, supplies and services at reasonable prices; the availability of capital to the Company; the Company’s ability to raise funds through its Partnership Drilling Programs; risks incident to the drilling and operation of oil and gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; the effect of oil and gas derivatives activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-K.

2005 Restatement

As previously mentioned under "Explanatory Note Regarding Restatement" on Page 2 and Note 22 on F-35, the Company is amending and restating its prior consolidated statements of income for the years ended December 31, 2004 and 2003, for the quarterly periods ended March 31, 2005, June 30, 2005 and September 30, 2005 and for each of the quarters ended in the years 2004 and 2003. The selected financial data for the years ended December 31, 2002 and 2001 has also been restated. The restatement is being made to correct errors in the reporting of certain revenues and expenses to properly reflect the elimination of transactions between the Company and the Company sponsored limited partnerships. The corrections resulted in the elimination of revenues and expenses of equal amounts. The restatement had no effect on net income, earnings per share, cash flows, proved oil and gas reserves, or the Company's financial position.

Results of Operations

Management Overview

The Company has recorded historically strong revenues, income and cash flow for 2005. High oil and natural gas prices in combination with record Company production were the largest contributors to both income and cash flow. The high energy prices increased the Company's revenues both for sales of Company-owned production and for gas purchased and sold by RNG, our natural gas marketing subsidiary. Management also believes that high energy prices made the Company’s partnership investment programs more attractive to investors resulting in a significant increase in the sale of program interests. This resulted in an increase of drilling activity, volume of production revenues, and gross profit for the Company's drilling and development segment. The new wells drilled for the partnerships also led to an increase in revenues for the Company to operate wells for the partnerships and others.

The increased level of activities also increased the costs associated with the drilling and development and well operations activities because goods, services and other costs were incurred as a result of the higher levels of activities and prices have increased in response to higher demand.

Profitability in 2005 was reduced by losses in derivative transactions relating to the Company’s oil and gas sales in the amount of $9.4 million as recorded in the “Oil and gas price risk management” line item in the income statement. These consisted of both realized and unrealized losses. Realized losses are cash losses incurred at the maturity of derivatives positions which amounted to $6.4 million during 2005. Unrealized losses are charges that reflect possible losses on derivative positions maturing in future periods, and may increase or decrease depending on the level of gas or oil prices at the date the derivatives mature or on the date they are closed, whichever occurs first, which amounted to $3.0 million during 2005.

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

Year Ended December 31, 2005 Compared with December 31, 2004

Revenues

Total revenues for the year ended December 31, 2005 were $343.1 million compared to a restated $267.8 million for the year ended December 31, 2004, an increase of approximately $75.3 million, or 28.1 percent. The increase was a result of increased drilling revenues, gas sales from natural gas marketing activities, oil and gas sales, well operations and pipeline income, and other income.

Costs and Expenses

Total costs and expenses for the year ended December 31, 2005 were $267.0 million compared to a restated $210.5 million for the year ended December 31, 2004, an increase of approximately $56.5 million or 26.8 percent. The increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production and well operations cost, exploratory dry hole costs, general and administrative expenses and depreciation, depletion and amortization.

Drilling Operations

Drilling revenues for the year ended December 31, 2005 were $100.0 million compared to a restated $94.1 million for the year ended December 31, 2004, an increase of approximately $5.9 million or 6.3 percent. Such increase was due to the increased drilling funds raised and drilled during the year through the Company's drilling programs. The two public and one private drilling program of 2005 raised $116 million compared to $100 million in 2004. We believe higher oil and natural gas prices and the resulting improved performance of our prior programs are the reasons for the increase in our drilling program sales.

Oil and gas well drilling operations costs for the year ended December 31, 2005 were $88.2 million compared to a restated $77.7 million for the year ended December 31, 2004, an increase of approximately $10.5 million or 13.5 percent. The increase was due to the higher levels of drilling activity from our public drilling programs referred to above and increased costs from higher charges for services and materials provided to the Company. The gross margin on the drilling activities for the year ended December 31, 2005 was 11.8 percent compared with 17.4 percent for the year ended December 31, 2004, a decrease in gross margin of approximately 5.6 percent. The decrease was due to significantly increasing well drilling and completion costs, particularly the costs of fracturing and rising steel costs for casing and other well equipment and oil field services. The private drilling partnership funded on December 30, 2005 with wells to be drilled during the first quarter 2006 and future partnerships will be drilled on a "cost plus basis"; that should reduce these fluctuations in drilling gross margins.

This new cost-plus drilling arrangement eliminates the Company's risk of loss, thus the drilling revenues and corresponding costs will be netted to a one-lined income statement item representing only the gross profit portion of the drilling arrangement. This would have a significant effect on the Company's 2006 gross drilling revenues and corresponding drilling expenses, but would not change the gross profit.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of RNG, the Company's marketing subsidiary for the year ended December 31, 2005 were $121.1 million compared to $94.6 million for the year ended December 31, 2004, an increase of approximately $26.5 million or 28.0 percent. The increase was the result of significantly higher average natural gas sales prices and higher volumes sold offset in part by an increase in unrealized losses on derivative transactions which amounted to approximately $9.2 million and $700,000 for the years ended December 31, 2005 and 2004, respectively.

The costs of gas marketing activities for the year ended December 31, 2005 were $119.6 million compared to $92.9 million for the year ended December 31, 2004, an increase of $26.7 million or 28.7 percent. The increase was due to higher average volumes of natural gas purchased for resale and significantly higher average purchase prices offset in part by an increase in unrealized gains on derivative transactions which amounted to approximately $9.7 million and $1.4 million for the years ended December 31, 2005 and 2004, respectively. Income before income taxes for the Company's natural gas marketing subsidiary decreased from $1.8 million for the year ended December 31, 2004 to $1.7 million for the year ended December 31, 2005. Based on the nature of the Company's gas marketing activities, derivatives did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the year ended December 31, 2005 were $102.6 million compared to $69.5 million for the year ended December 31, 2004, an increase of $33.1 million or 47.6 percent. The increase was due to higher volumes sold at significantly higher average sales prices of oil and natural gas. The volume of natural gas sold for the year ended December 31, 2005 was 11.0 million Mcf at an average price of $7.29 per Mcf compared to 10.4 million Mcf at an average sales price of $5.30 per Mcf for the year ended December 31, 2004. Oil sales for the year ended December 31, 2005 were 439,000 barrels at an average sales price of $50.56 per barrel compared to 381,000 barrels at an average sales price of $38.00 per barrel for the year ended December 31, 2004. The increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, wells drilled in our NECO, Colorado area of operation, and the investment in oil and gas properties we own in our public drilling program partnerships.

Oil and Gas Production

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

| | Year Ended December 31, 2005 | | | Year Ended December 31, 2004 | | |
|---|---|---|---|---|---|---|
| | Oil (Bbl) | Natural Gas (Mcf) | Natural Gas Equivalents (Mcfe) | Oil (Bbl) | Natural Gas (Mcf) | Natural Gas Equivalents (Mcfe) |
| Appalachian Basin | 3,973 | 1,631,552 | 1,655,390 | 4,893 | 1,812,407 | 1,841,765 |
| Michigan Basin | 4,732 | 1,555,958 | 1,584,350 | 5,786 | 1,728,435 | 1,763,151 |
| Rocky Mountains | 430,266 | 7,843,250 | 10,424,846 | 370,482 | 6,831,032 | 9,053,924 |
| Total | 438,971 | 11,030,760 | 13,664,586 | 381,161 | 10,371,874 | 12,658,840 |
| Average Sales Price | $50.56 | $7.29 | $7.51 | $38.00 | $5.30 | $5.49 |

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

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2007 we have in place a series of floors and ceilings on 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 December 31, 2005 the Company averaged natural gas volumes sold of 973,700 Mcf per month and oil sales of 36,050 barrels per month. The positions in effect as of April 30, 2006 on the Company's share of production (The table below does not include positions related to Riley Marketing activities or derivative contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner) by area are shown in the following table.

| | | Floors | | Ceilings | |
|---|---|---|---|---|---|
| | | Monthly Quantity Mmbtu | Contract Price | Monthly Quantity Mmbtu | Contract Price |
| Month Set | Month | | | | |
| Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin) | | | | | |
| Jan-05 | Jan 2006 – Mar 2006 | 60,000 | $4.50 | 30,000 | $7.15 |
| Jul-05 | Jan 2006 – Mar 2006 | 27,500 | $6.50 | 13,750 | $8.27 |
| Sep-05 | Jan 2006 – Mar 2006 | 78,700 | $9.00 | – | – |
| Mar-05 | Apr 2006 – Oct 2006 | 42,000 | $4.50 | 21,000 | $7.25 |
| Jul-05 | Apr 2006 – Oct 2006 | 27,500 | $5.50 | 13,750 | $7.63 |
| Jul-05 | Nov 2006 – Mar 2007 | 27,500 | $6.00 | 13,750 | $8.40 |
| Feb-06 | Nov 2006 – Mar 2007 | 60,000 | $6.50 | – | – |
| Feb-06 | Apr 2007 – Oct 2007 | 44,000 | $5.50 | – | – |
| NYMEX Based Derivatives - (Appalachian and Michigan Basins) | | | | | |
| Jan-05 | Jan 2006 – Mar 2006 | 156,000 | $5.00 | 78,000 | $8.50 |
| Sep-05 | Jan 2006 – Mar 2006 | 156,000 | $10.50 | – | – |
| Mar-05 | Apr 2006 – Oct 2006 | 78,000 | $5.50 | 39,000 | $7.40 |
| Jul-05 | Apr 2006 – Oct 2006 | 61,000 | $6.25 | 30,000 | $8.98 |
| Jul-05 | Nov 2006 – Mar 2007 | 68,000 | $7.00 | 34,000 | $9.27 |
| Feb-06 | Nov 2006 – Mar 2007 | 34,000 | $8.00 | – | – |
| Feb-06 | Nov 2006 – Mar 2007 | 34,000 | $8.50 | 34,000 | $13.73 |
| Feb-06 | Apr 2007 – Oct 2007 | 34,000 | $7.00 | – | – |
| Feb-06 | Apr 2007 – Oct 2007 | 34,000 | $7.50 | 34,000 | $10.83 |
| NYMEX Based Derivatives (NECO) | | | | | |
| Jan-05 | Jan 2006 – Mar 2006 | 150,000 | $5.00 | 75,000 | $8.45 |
| Panhandle Based Derivatives (NECO) | | | | | |
| Sep-05 | Jan 2006 – Mar 2006 | 100,000 | $10.00 | – | – |
| Mar-05 | Apr 2006 – Oct 2006 | 150,000 | $5.00 | 75,000 | $8.62 |
| Jul-05 | Nov 2006 – Mar 2007 | 150,000 | $6.50 | 75,000 | $8.56 |
| Feb-06 | Apr 2007 – Oct 2007 | 60,000 | $6.00 | – | – |
| Feb-06 | Apr 2007 – Oct 2007 | 60,000 | $6.50 | 60,000 | $9.80 |

Well Operations and Pipeline Income

Well operations and pipeline income for the year ended December 31, 2005 were $8.8 million compared to a restated $7.7 million for the year ended December 31, 2004, an increase of approximately $1.1 million or 14.3 percent. The increase was due to an increase in the number of wells and pipeline systems operated by the Company for our public drilling programs as well as for third parties.

Other Income

Other income for the year ended December 31, 2005 was $10.7 million compared to a restated $1.9 million for the year ended December 31, 2004, an increase of $8.8 million. The increase is a result of a sale of a portion of one of our undeveloped leases in Garfield County, Colorado, which we sold to an unaffiliated entity in the first quarter of 2005 for a pre-tax gain of $6.2 million, a second quarter gain on sale to an unaffiliated party of some Pennsylvania wells in the amount of $1.7 million, management fees collected from the funding of three drilling partnerships, and interest earned on higher average cash balances and higher interest rates.

### Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company’s producing properties for the year ended December 31, 2005 were $19.9 million compared to a restated $17.3 million for the year ended December 31, 2004, an increase of approximately $2.6 million or 15.0 percent. The increase was due to the increased production costs and severance and property taxes on the increased volumes and higher average sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting costs per Mcfe increased from a restated $1.12 per Mcf for the year ended December 31, 2004 to $1.19 per Mcfe for the year ended December 31, 2005 due to increased severance and property taxes on the significantly increased oil and gas sales prices along with additional well workovers and production enhancements work performed.

### Exploratory Dry Hole Costs

The Company drilled eight exploratory wells in 2005 of which five were deemed to be dry holes. In the fourth quarter of 2005 four Kansas wells were drilled and plugged and abandoned for a total combined cost of $314,200, which included lease acreage with cost of $70,600 which was deemed impaired. Also in the fourth quarter the Coffeepot Springs #24-34 well in Colorado was determined to be uneconomical at a total dry hole cost of approximately $5.42 million, which included lease acreage with a cost of $90,000 which was deemed impaired. In the second quarter of 2005, it was determined the Fox Federal #1-13 well which was drilled in 2004 in Colorado was also an uneconomic well and total costs of approximately $5.39 million were expensed, which included lease acreage with a cost of $384,000 which was deemed impaired. These exploratory dry hole expenses were expensed in the period in which it was determined that the well was unsuccessful in accordance with the successful efforts method of accounting. All costs were incurred 100% by the Company because the drilling fund partnerships did not participate in these exploratory wells.

### General and Administrative Costs

General and administrative expenses for the year ended December 31, 2005 increased to $7.0 million compared to $4.5 million for the year ended December 31, 2004 an increase of approximately $2.5 million or 55.6 percent. The increase was primarily due to increased costs of complying with the various provisions of Sarbanes-Oxley, in particular Section 404 (Internal Controls), the cost of the Company's financial statement restatements and increased personnel costs for the increased number of employees.

### Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the year ended December 31, 2005 increased to $21.1 million from approximately $18.2 million for the year ended December 31, 2004, an increase of approximately $2.9 million or 15.9 percent. Such increase was due to the significantly increased production and investment in oil and gas properties by the Company as referred to above.

### Interest Expense

Interest expense for the year ended December 31, 2005 was $682,000 compared to $674,000 for the year ended December 31, 2004, an increase of $8,000 or 1.2 percent. Such increase is due to increased accretion of the Company's asset retirement obligation and rising interest rates offset in part by lower average outstanding balance of our credit facility. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of interest expense. The average outstanding debt balances for the year ended December 31, 2005 was $4.1 million compared to $11.3 million for the year ended December 31, 2004.

### Oil and Gas Price Risk Management Loss, Net

Oil and gas price risk management loss, net for the year ended December 31, 2005 was $9.4 million compared to approximately $3.1 million for the year ended December 31, 2004, an increase of $6.3 million. For the year ended December 31, 2005, the Company recorded unrealized losses of $3.0 million and realized losses of $6.4 million compared to the year ended December 31, 2004, which is comprised of unrealized losses of $1.5 million and realized losses of $1.6 million. The Company’s strategy in its derivative policy is to provide protection on declining oil and natural gas prices. During 2005 the Company experienced rising oil and natural gas pricing environment, this trend caused the Company to record losses in its derivative transactions. In a declining oil and natural gas pricing environment the Company would in theory record gains in its derivative transaction activities. Oil and gas price risk management (gain) loss, net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production (this line item does not include commodity based derivative transactions related to transactions from marketing activities).

### Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes decreased from 37.9% for the year ended December 31, 2004 to 37.3% for the year ended December 31, 2005 primarily as a result of the domestic production activities deduction.

Net Income and Earnings Per Share

Net income for the year ended December 31, 2005 was $41.5 million compared to a net income of $33.2 million for the year ended December 31, 2004, an increase of approximately $8.3 million or 25.0 percent.

Diluted earnings per share for the year ended December 31, 2005 was $2.52 per share compared to $2.00 per share for the year ended December 31, 2004, an increase of $0.52 per share or 26.0 percent.

Year Ended December 31, 2004 Compared with December 31, 2003

Revenues

Total revenues for the year ended December 31, 2004 were a restated $267.8 million compared to a restated $189.5 million for the year ended December 31, 2003, an increase of approximately $78.3 million, or 41.3 percent. The increase was a result of increased drilling revenues, gas sales from natural gas marketing activities, oil and gas sales and well operations and pipeline income.

Oil and Gas Well Drilling Revenue

Drilling revenues for the year ended December 31, 2004 were a restated $94.1 million compared to a restated $57.5 million for the year ended December 31, 2003, an increase of approximately $36.6 million or 63.7 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The four drilling programs of 2004 raised $100 million compared to $78.3 million in 2003. We believe higher oil and natural gas prices and the resulting improved performance of our prior programs are the reasons for the increase in our 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 year ended December 31, 2004 were $94.6 million compared to $73.1 million for the year ended December 31, 2003, an increase of approximately $21.5 million or 29.4 percent. The increase was the result of significantly higher average natural gas sales prices and higher volumes sold.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the year ended December 31, 2004 were $69.5 million compared to $48.4 million for the year ended December 31, 2003, an increase of $21.1 million or 43.6 percent. The increase was due to significantly higher volumes sold at substantially higher average sales prices of oil and natural gas. The volume of natural gas sold for the year ended December 31, 2004 was 10.4 million Mcf at an average price of $5.30 per Mcf compared to 8.7 million Mcf at an average sales price of $4.58 per Mcf for the year ended December 31, 2003. Oil sales for the year ended December 31, 2004 were 381,000 barrels at an average restated sales price of $38.00 per barrel compared to 289,000 barrels at an average sales price of $29.43 per barrel for the year ended December 31, 2003.

Since no acquisitions were made in 2004, the increase in production resulted primarily from the new wells drilled by the Company in 2004, recompletions of Wattenberg Field wells, and completion of behind pipe zones in the Appalachian Basin. Also the three acquisitions made in 2003 contributed to the increase to the extent they were not owned for the full year of 2003, but were in 2004.

Oil and Gas Production

The Company's oil and gas production by area of operations along with average sales price (excluding derivative gains/losses) is presented below:

| | Year Ended December 31, 2004 | | | Year Ended December 31, 2003 | | |
|---|---|---|---|---|---|---|
| | Oil (Bbl) | Natural Gas (Mcf) | Natural Gas Equivalents (Mcfe) | Oil (Bbl) | Natural Gas (Mcf) | Natural Gas Equivalents (Mcfe) |
| Appalachian Basin | 4,893 | 1,812,407 | 1,841,765 | 3,992 | 1,921,200 | 1,945,152 |
| Michigan Basin | 5,786 | 1,728,435 | 1,763,151 | 6,627 | 1,832,737 | 1,872,499 |
| Rocky Mountains | 370,482 | 6,831,032 | 9,053,924 | 278,874 | 4,958,245 | 6,631,489 |
| Total | 381,161 | 10,371,874 | 12,658,840 | 289,493 | 8,712,182 | 10,449,140 |
| Average Price | $38.00 | $5.30 | $5.49 | $29.43 | $4.58 | $4.63 |

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

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through October of 2006 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 December 31, 2004 the Company averaged natural gas volumes sold of 872,000 Mcf per month and oil sales of 31,000 barrels per month. The positions in effect as of March 31, 2005 on the Company's share of production (The table below does not include positions related to Riley Marketing activities or derivative contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner) by area are shown in the following table.

| | | Floors | | Ceilings | |
|---|---|---|---|---|---|
| Month Set | Month | Monthly Quantity Mmbtu | Contract Price | Monthly Quantity Mmbtu | Contract Price |
| | NYMEX Based Derivatives - (Appalachian and Michigan Basin) | | | | |
| 5/04 | Jan 2005 – Mar 2005 | 180,000 | $5.67 | 90,000 | $7.00 |
| 2/04 | Apr 2005 – Oct 2005 | 122,000 | $4.28 | 61,000 | $5.00 |
| 3/05 | Apr 2005 – Oct 2005 | 39,000 | $5.75 | 19,500 | $8.37 |
| 1/05 | Nov 2005 – Mar 2006 | 156,000 | $5.00 | 78,000 | $8.50 |
| 3/05 | Apr 2006 –Oct 2006 | 78,000 | $5.50 | 39,000 | $7.40 |
| | Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin) | | | | |
| 5/04 | Jan 2005 – Mar 2005 | 60,000 | $5.04 | 30,000 | $6.00 |
| 2/04 | Apr 2005- Oct 2005 | 33,000 | $3.10 | 16,000 | $4.43 |
| 3/05 | Apr 2005 – Oct 2005 | 38,000 | $4.75 | 19,000 | $8.12 |
| 1/05 | Nov 2005 - Mar 2006 | 60,000 | $4.50 | 30,000 | $7.15 |
| 3/05 | Apr 2006 – Oct 2006 | 42,000 | $4.50 | 21,000 | $7.25 |

| | | | | | |
|---|---|---|---|---|---|
| | Colorado Interstate Gas (CIG) Based Derivatives (Wattenberg) | | | | |
| 7/04 | Jan 2005 – Mar 2005 | 80,000 | $5.00 | 40,000 | $6.20 |
| | NYMEX Based Derivatives (NECO) | | | | |
| 7/04 | Jan 2005 – Mar 2005 | 150,000 | $5.32 | - | - |
| 2/04 | Apr 2005 – Oct 2005 | 150,000 | $4.26 | 75,000 | $5.00 |
| 1/05 | Nov 2005 - Mar 2006 | 150,000 | $5.00 | 75,000 | $8.45 |
| | Oil - NYMEX Based Derivatives (Wattenberg) | | | | |
| | | Bbls | | Bbls | |
| 8/04 | Jan 2005 – Dec 2005 | 15,000 | $32.30 | 7,500 | $40.00 |

Well Operations, Pipeline & Other Income

Well operations and pipeline income for the year ended December 31, 2004 were a restated $7.7 million compared to a restated $6.9 million for the year ended December 31, 2003, an increase of approximately $800,000 or 11.6 percent. The increase was due to an increase in the number of wells and pipeline systems operated by the Company for our public drilling programs as well as for third parties. Other income for the year ended December 31, 2004 was a restated $1.9 million compared to a restated $3.5 million for the year ended December 31, 2003, a decrease of $1.6 million or 45.7 percent. Other income in 2003 included $1.0 million of life insurance proceeds. In 2004 the Company, for competitive reasons, lowered the management fee it charges to its drilling partnerships to 1-1/2% of subscriptions, from 2-1/2% of subscriptions.

Costs and Expenses

Costs and expenses for the year ended December 31, 2004 were a restated $210.5 million compared to a restated $152.9 million for the year ended December 31, 2003, an increase of approximately $57.6 million or 37.7 percent. The increase was primarily the result of increased cost of oil and gas well drilling operations, gas purchased for gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.

Oil and Gas Well Drilling Costs

Oil and gas well drilling operations costs for the year ended December 31, 2004 were a restated $77.7 million compared to a restated $46.9 million for the year ended December 31, 2003, an increase of approximately $30.8 million or 65.7 percent. The 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 year ended December 31, 2004 was 17.4 percent compared with 18.4 percent for the year ended December 31, 2003, a decrease in gross margin of approximately 1.0 percent. Such decrease was due to significantly increasing well drilling and completion costs, particularly the costs of fracturing and rising steel costs for casing and other well equipment. For the first two partnerships in 2005, the Company raised its turnkey rates charged to its Public Drilling Partnerships to reverse this declining trend in gross margins.

Cost of Gas Marketing Activities

The costs of gas marketing activities for the year ended December 31, 2004 were $92.9 million compared to $72.4 million for the year ended December 31, 2003, an increase of $20.5 million or 28.3 percent. The increase was due to the significantly higher average prices of natural gas purchased and higher volumes purchased for resale. Income before income taxes for the Company's natural gas marketing subsidiary improved from $762,000 for the year ended December 31, 2003 to $1,737,000 for the year ended December 31, 2004. Based on the nature of the Company's gas marketing activities, derivatives did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the year ended December 31, 2004 were a restated $17.3 million compared to a restated $13.3 million for the year ended December 31, 2003, an increase of approximately $4.0 million or 30.0% percent. Such increase was due to the increased production costs and severance and property taxes on the increased volumes and higher sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting cost per Mcfe increased from $0.93 per Mcfe to $1.12 per Mcfe due to increased severance and property taxes on the significantly increased oil and gas sales prices along with additional well workovers and production enhancements work performed.

General and Administrative Costs

General and administrative expenses for the year ended December 31, 2004 decreased to $4.5 million compared with $5.0 million for the year ended December 31, 2003 a decrease of approximately $469,000 or 9.4 percent. The decrease was primarily due to lower executive compensation costs partially offset by approximately $477,000 of costs of complying with the various provisions of Sarbanes-Oxley, in particular with Section 404 (Internal Controls).

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the year ended December 31, 2004 increased to $18.2 million from approximately $15.3 million for the year ended December 31, 2003, an increase of approximately $2.9 million or 19.0 percent. Such increase was due to the significantly increased production and investment in oil and gas properties by the Company as referred to above.

Interest Expense

Interest expense for the year ended December 31, 2004 was $674,000 compared to $1.2 million for the year ended December 31, 2003, a decrease of $526,000 or 43.8 percent. The impact of the derivative on interest expense was a reduction of $592,700 and $477,600 for the years ended December 31, 2004 and 2003, respectively. Such decrease is due to a lower average outstanding balance of our credit facility offset in part by rising interest rates. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of interest. The average outstanding debt balances for the year ended December 31, 2004 was $11.3 million compared to $24.1 million for the year ended December 31, 2003.

Oil and Gas Price Risk Management Loss, Net

Oil and gas price risk management loss, net for the year ended December 31, 2004 was $3.1 million compared to approximately $800,000 for the year ended December 31, 2003, an increase of $2.3 million. Oil and gas price risk management, net is comprised of both the realized and unrealized portions of the Company’s commodity based derivative transactions for its oil and gas production (this line item does not include commodity based derivative transactions related to transactions from marketing activities). The Company views these transactions as financial instruments and not a part of our oil and gas sales. The 2004 change is the result of increasing oil and natural gas prices.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from 34.5% for the year ended December 31, 2003 to 37.9% for the year ended December 31, 2004 primarily as a result of significantly increased earnings of the Company during 2004, lower percentage depletion for tax purposes, the benefit in 2003 of officers’ life insurance proceeds, and non-conventional source fuel tax credit.

Net Income and Earnings Per Share

Net income for the year ended December 31, 2004 was $33.2 million compared to a net income of $20.4 million for the year ended December 31, 2003, an increase of approximately $12.8 million or 62.7 percent.

Diluted earnings per share for the year ended December 31, 2004 was $2.00 per share compared to $1.25 per share for the year ended December 31, 2003, an increase of $0.75 per share or 60.0 percent.

Liquidity and Capital Resources

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

Natural Gas Pricing and Pipeline Capacity

The Company sells natural gas under contracts that are priced based on spot prices or price indexes that reflect current market prices for the commodity. As a result variations in the market are reflected in the revenue we receive. The price of natural gas has varied substantially over short periods of time in the past, and there is every reason to expect a continuation of that variability in the future. During 2005 prices for natural gas were close to or above record levels, and future expectations as reflected in the NYMEX futures market are for continuing high price levels for 2006 and beyond. Strong domestic and international demand for energy and inadequate short term supplies are believed to be key causes of the strong prices. High prices could encourage the development of new energy sources and reduced consumption as users find more efficient ways to use energy or substitute other energy forms. High energy prices could also slow global economic growth, further reducing demand. As a result the energy price outlook could change rapidly from current expectations. Reduced natural gas prices would reduce the profitability and cash flow from the Company's gas production operations.

Natural gas prices throughout the country tend to be fairly closely related after allowing for differences in the quality and energy content of the gas, the location and distance to market, and other factors. Sometimes prices in a particular area may vary from historical relationships. This can occur when a local condition restricts the marketability of the natural gas. For example limits on pipeline delivery capacity for natural gas can result in lower than normal prices for wells that use the system to deliver gas to market. This situation occurred in 2002 to 2003 in the Rocky Mountains, when the productive capacity of wells in the region exceeded the amount of gas that could be used by local markets or shipped out of the area. In order to access the available capacity producers were forced to sell their gas at lower than normal prices with the alternative being to shut wells in. Since that time, additional pipeline capacity has been added, and further additions are planned in the future, so prices have returned to the historical relationship to other producing regions. However future delivery constraints could result in lower than anticipated prices or production in any of the Company's producing areas.

Oil Pricing

Oil prices were near or above record levels for most of 2005. The Company's oil prices are largely determined by oil prices in the world market. Global supply and demand and geopolitical factors are the key determinants of oil prices. The rapid growth of energy use in developing countries, most notably China, is driving a rapid increase in worldwide oil consumption. Higher prices could result in reduced consumption and/or increasing supplies that could moderate the current high price levels. Over the past several years oil has been an increasing part of the Company's production mix. As a result higher oil prices have contributed to the Company's increased revenue from oil and gas sales more than in the past, and the Company would suffer a greater impact if oil prices were to decrease.

Oil and Gas Derivative Activities

Because of the uncertainty surrounding natural gas and oil prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2007 we have in place a series of floors and ceilings on part of our natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. See previous pages in this Management's Discussion and Analysis for a schedule of derivative positions.

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

Drilling Programs

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

In April, 2005, the Company commenced sales and funded its second 2005 Partnership (PDC 2005-B) at its maximum allowable subscriptions of $40 million. The Company commenced drilling operations of this partnership late in the second quarter and drilled for the partnership during the third and fourth quarters of 2005.

In December, 2005, the Company commenced sales and funded its third 2005 partnership, a private limited partnership, Rockies Region Private Limited Partnership with subscriptions of approximately $36 million. Drilling operations commenced in the first quarter of 2006.

The Company invests, as its equity contribution to each drilling partnership, a sum equal to approximately 22%-32% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. During 2005 this amounted to an investment of approximately $29.0 million in our drilling partnerships. No assurance can be made that the Company will continue to receive this level of funding from these or future programs. The Company posts, during the subscription period of a partnership, daily the amount of subscriptions that have been sold in the partnership at its website, www.petd.com under the heading of "Drilling Program".

Substantially all of the Company's drilling programs contain a repurchase provision allowing Investors to request that the Company repurchase their partnership units. This repurchase provision is in effect any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if investors request that the Company repurchase the units and subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $9.2 million. The Company has adequate liquidity to meet this obligation. During 2005 the Company spent $352,000 under this provision. As of December 31, 2005, outstanding repurchase offers to investing partners totaled $256,400. In 2006, $70,700 of such outstanding offers were consummated prior to their expiration on or before February 28, 2006.

Drilling Activity

During 2005 the Company and its drilling fund partnerships drilled a total of 132 wells with 2 developmental dry holes. The Company drilled 99 successful wells in its Wattenberg field in the Denver-Julesburg Basin and 33 successful wells in the Piceance Basin in western Colorado. The Company plans to conduct its 2006 partnership drilling activity in these two areas, as well as in the Red Desert Basin in Wyoming.

During 2005 the Company drilled several development wells outside of the public drilling fund partnerships. The Company drilled 57 wells on its northeast Colorado properties and participated in 24 additional wells which were drilled by joint venture partners. Of these 81 wells, 79 were successful. The Company also drilled 20 Wattenberg Field wells for its own account, all 20 were successful. The Company also drilled a developmental gas well in the Michigan Basin.

The total dry hole costs of $11.1 million associated with the six wells described below (five drilled in 2005, one in 2004) were expensed in accordance with the successful efforts method of accounting. All costs for the six wells were incurred 100% by the Company, as no costs were incurred by the drilling fund partnerships. The Company drilled eight new exploratory wells in 2005. In addition, one well, which was drilled in 2004, was determined to be a dry hole in 2005. Three of the eight wells drilled in 2005 were successful and five were dry holes.

Three of the wells were drilled in North Dakota (two in the Bakken Shale and one non-operated in the Nessen Shale). One Bakken Shale well was successful and the other two wells were in the process of being drilled and completed and had combined expenditures of $1.9 million as of December 31, 2005. If either or both of these wells are determined to be dry holes, those costs will be expensed in the period when the determination is made as required by the successful efforts method of accounting.

During the fourth quarter of 2005 the Coffeepot Springs #24-34 well located in Colorado was determined to be uneconomic and had a total dry hole cost of $5.42 million along with four unsuccessful shallow exploratory wells were drilled in Kansas for a total dry hole cost of $314,200.

During the second quarter of 2005, the Fox Federal #1-13 located in Colorado (for which drilling was begun 2004), was determined to be a dry hole at a cost of approximately $5.38 million.

Purchase of Oil and Gas Properties

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

Costs incurred by the Company in oil and gas property acquisition, exploration and development for the year ended December 31, 2005 are presented below:

| | |
|---|---|
| Acquisition of properties: | |
| Unproved properties | $16,910,200 |
| Proved properties | 1,608,300 |
| Development costs | 68,605,000 |
| Exploration costs | 12,942,700 |
| | $100,066,200 |

Common Stock Repurchase

On March 18, 2005 the Company publicly announced the authorization by its Board of Directors to repurchase up to 2% of the Company's outstanding common stock (331,796 shares) at fair market value at the date of purchase. At a meeting held June 10, 2005, the Board of Directors of Petroleum Development Corporation approved an amendment of the size of the stock repurchase from 2% to 10% (1,658,980 shares) of the Company's then outstanding common stock. Under the program, management has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program expired on December 31, 2005. The following activity has occurred from inception of the plan on March 18, 2005 until December 31, 2005.

| | |
|---|---|
| Month of Purchase | May, 2005 |
| Average Price Paid per Share | $23.75 |
| Broker/Dealer | McDonald Investments |
| Number of Shares Purchased | 331,796 |
| Remaining Number of Shares to Purchase | 1,327,184 |

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

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

Working Capital

Although the working capital of the Company as of December 31, 2005 is a negative $25.8 million this amount included a net current liability of $7.9 million related to the fair value of derivatives. The amount may or may not be realized depending on the change in the fair value of derivatives upon settlement, and if realized will be funded with proceeds from future oil and gas sales. The Company manages its working capital needs by only drawing from its credit facility of $200 million as liabilities come due and cash is required. At December 31, 2005, the Company has adequate liquidity with the credit facility to meet both its working capital and needs for continued investment in oil and gas well drilling over the next year.

Long-Term Debt

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

As of December 31, 2005 the outstanding balance was $24,000,000. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. At December 31, 2005, the outstanding balance was subject to a prime rate of 7.25%. As of the filing of this Form 10-K, the Company was in compliance with all covenants in the credit agreement, except for timely filing of this December 31, 2005 Form 10-K. The Company has received bank waivers to extend the due date of the December 31, 2005 consolidated financial statements until May 31, 2006, and the filing of the March 31, 2006 consolidated financial statements until June 15, 2006..

Contractual Obligations and Contingent Commitments

Contractual obligations and contingent commitments and due dates are as follows:

| | Payments due by period | | | | |
|---|---|---|---|---|---|
| Contractual Obligations and Contingent Commitments | Total | Less than 1 year | 1-3 years | 3-5 years | More than 5 years |
| Long-Term Debt | $ 24,000,000 | $ - | $ - | $24,000,000 | $ - |
| Operating Leases | 1,432,200 | 356,300 | 589,100 | 458,800 | 28,000 |
| Asset Retirement Obligations | 8,333,200 | 50,000 | 100,000 | 100,000 | 8,083,200 |
| Drilling Rig Commitment | 59,627,400 | 20,221,000 | 31,922,000 | 7,484,400 | - |
| Derivative Agreements (1) | 22,062,500 | 18,424,400 | 3,638,100 | - | - |
| Partnership Performance Supplement (2) | 4,808,400 | 1,256,700 | 3,099,500 | 409,800 | 42,400 |
| Other Liabilities | 3,722,600 | 40,000 | 250,000 | 250,000 | 3,182,600 |
| Total | $ 123,986,300 | $ 40,348,400 | $ 39,598,700 | $ 32,703,000 | $ 11,336,200 |

(1) Amount represents gross liability related to fair value of derivatives. Includes fair value of derivatives for Riley Natural Gas, Petroleum Development Corporation's share of oil and gas production and derivatives contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner. The Company has a corresponding receivable from the Partnerships of $5,351,500 as of December 31, 2005.

(2) Represents maximum amount the Company would be required to pay to investing partners if certain levels of Partnership performance are not met as of December 31, 2005. See Note 10 to the consolidated financial statements.

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

Commitments and Contingencies

As Managing General Partner of 75 partnerships (See Item 1. Business – Drilling and Development) the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes its and its subcontractors' casualty insurance coverage is adequate to meet this potential liability.

Critical Accounting Policies and Estimates

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

Principles of Consolidation

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

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our sponsored drilling programs using the percentage of completion method. These contracts include the sale of equipment and the providing of services at footage rates and are completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision for the drilling and completion process and uses subcontractors to perform drilling and completion services. Revenues are recognized under the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed periodically during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that our estimated costs exceed the estimated contract revenue. In 2005, the Company recorded a loss of $800,000 on uncompleted drilling contracts as part of Cost of Oil and Gas Well Drilling Operations. The Company did not experience any contract losses in 2004 or 2003.

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

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

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

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

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

Valuation of Accounts Receivable

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

Accounting for Derivatives Contracts at Fair Value

The Company uses derivative instruments to manage its commodity and financial market risks. Accounting requirements for derivatives and hedging activities are complex; interpretation of these requirements by standard-setting bodies is ongoing. The Company currently does not use hedge accounting treatment for its derivatives.

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

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

Use of Estimates in Long-Lived Asset Impairment Testing

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

Oil and Gas Properties

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

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

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

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

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

Deferred Tax Asset Valuation Allowance

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

Recently Adopted Accounting Standards

The FASB issued FIN 46R, "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 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 46R requires the consolidation of entities which are determined to be VIEs where 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 return, or both). The amended interpretation was effective for the first interim 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 the partnerships are not VIEs.

In June 2005, the EITF reached a consensus on EITF Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights". This consensus applies to voting right entities not within the scope of FASB Interpretation No. 46R, “Consolidation of Variable Interest Entities”, in which the investor is the general partner in a limited partnership or functional equivalent. The EITF consensus is that the general partner in a limited partnership is presumed to control that limited partnership regardless of the extent of the general partner’s ownership interest and, therefore, should include the limited partnership in its consolidated financial statements unless the limited partners have substantive participating or kick-out rights. Pursuant to the partnership agreements the presumption of control by the Company, the general partner, is overcome because the investor partners have substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner through substantive kick-out rights that can be exercised by a vote of simple majority of the investor partner units not held by the general partners without having to show cause. On the basis of this assessment, the partnership interests of the Company continue to be proportionately consolidated as disclosed above.

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

Recently Issued Accounting Standards

On December 16, 2004, the FASB issued SFAS No. 123(R) "Accounting for Share-Based Payments" and has issued several subsequent Staff Positions clarifying this guidance. This guidance replaced previously existing requirements under SFAS No. 123 and APB No. 25. Under SFAS No. 123(R), an entity must recognize the compensation cost related to employee services received in exchange for all forms of share-based payments to employees, including employee stock options, as an expense in its income statement. The compensation cost of awards will generally be measured based on the grant-date fair value of the award. The Company will be required to adopt SFAS No. 123(R) in the first quarter of 2006. The Company intends to use the modified prospective method for adoption of SFAS No. 123(R) as permitted by the guidance.

The Company has determined that the impact of SFAS No. 123(R) and related guidance will not be material to its financial statements. In accordance with SFAS No. 123, the Company has historically disclosed the impact on the Company’s net income and earnings per share had the fair value based method been adopted. Had the Company adopted SFAS No. 123(R) in prior periods, the impact of that standard on periods presented in these Consolidated Financial Statements would have approximated the impact of SFAS No. 123 as described in the disclosure of pro forma net income and earnings per share presented in Note 1.

In December 2004, the FASB issued FAS 153, "Exchange of Nonmonetary Assets", an amendment of APB Opinion 29, "Accounting for Nonmonetary Transactions". This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under FAS 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance criterion and fair value is determinable, the transaction must be accounted for at fair value resulting in recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. The adoption of this statement will not have a material impact on our results of operations or financial position.

In June 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections" – a replacement of APB Opinion No. 20 and FASB Statement No. 3, which replaces Accounting Principles Board Opinion No. 20, "Accounting Changes", and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements", and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Consequently, we will adopt the provisions of SFAS 154 for our fiscal year beginning January 1, 2006. We currently believe that adoption of the provisions of SFAS No. 154 in 2006 will not have a material impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk.

Market-Sensitive Instruments and Risk Management

The Company's primary market risk exposures are interest rate risk and commodity price risk. These exposures are discussed in detail below:

Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of December 31, 2005 is $68.5 million with an average interest rate of 3.5%. As of December 31, 2005, the Company had long-term debt of $24,000,000 subject to a prime interest rate of 7.25%.

Commodity Price Risk

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

The following tables summarize the open derivative and fixed-price purchase and sale contracts for Riley Natural Gas and Petroleum Development Corporation as of December 31, 2005 and 2004.

Riley Natural Gas
Open Derivative Positions

| Commodity | Type | Quantity Gas-Mmbtu | Weighted Average Price | Total Contract Amount | Fair Value |
|---|---|---|---|---|---|
| Total Positions as of December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Futures/Swaps Purchases | 1,025,500 | $ 9.05 | $9,283,010 | $ 1,983,352 |
| Natural Gas | Cash Settled Futures/Swaps Sales | 3,149,000 | $ 7.95 | $25,018,610 | $ (8,688,840) |
| Natural Gas | Cash Settled Basis Swap Purchases | 450,000 | $ 0.91 | $409,500 | $ (157,663) |
| Natural Gas | Cash Settled Basis Swap Sales | 240,000 | $ 0.50 | $120,000 | $ 3,700 |
| Natural Gas | Physical Purchases | 2,819,000 | $ 8.32 | $23,456,726 | $ 7,858,489 |
| Natural Gas | Physical Sales | 585,222 | $ 10.72 | $6,272,822 | $ (670,419) |
| Natural Gas | Physical Basis Purchases | 240,000 | $ 0.45 | $108,000 | $ 8,300 |
| Natural Gas | Physical Basis Sales | 450,000 | $ 0.94 | $420,750 | $ 168,913 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Positions maturing in 12 months following December 31, 2005 | | | | | | | |
| Natural Gas | Cash Settled Futures/Swaps Purchases | 1,025,500 | $ | 9.05 | $9,283,010 | $ | 1,983,352 |
| Natural Gas | Cash Settled Futures/Swaps Sales | 2,709,000 | $ | 8.12 | $21,991,390 | $ | (7,185,253) |
| Natural Gas | Cash Settled Basis Swap Purchases | 450,000 | $ | 0.91 | $409,500 | $ | (157,663) |
| Natural Gas | Cash Settled Basis Swap Sales | 220,000 | $ | 0.50 | $110,000 | $ | 4,900 |
| Natural Gas | Physical Purchases | 2,379,000 | $ | 8.71 | $20,717,126 | $ | 5,966,998 |
| Natural Gas | Physical Sales | 585,222 | $ | 10.72 | $6,272,822 | $ | (670,419) |
| Natural Gas | Physical Basis Purchases | 220,000 | $ | 0.45 | $99,000 | $ | 6,100 |
| Natural Gas | Physical Basis Sales | 450,000 | $ | 0.94 | $420,750 | $ | 168,913 |
| | | | | | | | |
| Prior Year Total Positions as of December 31, 2004 | | | | | | | |
| Natural Gas | Cash Settled Sale | 3,260,000 | $ | 5.60 | $18,249,250 | $ | (1,982,964) |
| Natural Gas | Cash Settled Purchase | 1,130,000 | $ | 6.77 | $7,644,540 | $ | (486,490) |
| Natural Gas | Cash Settled Sale Option | 530,000 | $ | 5.30 | - | $ | 134,242 |
| Natural Gas | Cash Settled Purchase Option | 265,000 | $ | 7.00 | - | $ | (85,541) |
| Natural Gas | Physical Contract Sale | 1,136,230 | $ | 6.96 | $7,908,865 | $ | 1,268,721 |
| Natural Gas | Physical Contract Purchase | 3,223,000 | $ | 5.82 | $18,747,564 | $ | 1,882,984 |

The maximum term for the derivative contracts listed above is 34 months.

Petroleum Development Corporation
Open Derivative Positions

| Commodity | Type | Quantity Gas-Mmbtu Oil-Barrels | Weighted Average Price | Total Contract Amount | Fair Value |
|---|---|---|---|---|---|
| Total Positions as of December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Option Sales | 5,665,000 | $8.17 | $46,273,550 | $ (12,531,796) |
| Natural Gas | Cash Settled Option Purchases | 14,030,000 | $6.36 | $89,210,000 | $ 2,660,289 |
| | | | | | |
| Positions maturing in 12 months following December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Option Sales | 4,930,000 | $8.07 | $39,802,550 | $ (10,411,106) |
| Natural Gas | Cash Settled Option Purchases | 12,560,000 | $6.38 | $80,165,000 | $ 2,251,533 |
| | | | | | |
| Prior Year Total Positions as of December 31, 2004 | | | | | |
| Natural Gas | Purchase | 120,000 | $6.63 | $796,150 | $ (45,680) |
| Natural Gas | Sale Option | 7,400,000 | $4.46 | - | $ 917,553 |
| Natural Gas | Purchase Option | 3,475,000 | $5.42 | - | $ (3,138,210) |
| Crude Oil | Sale Option | 360,000 | $32.30 | - | $ 306,702 |
| Crude Oil | Purchase Option | 180,000 | $40.00 | - | $ (973,638) |

The maximum term for the derivative contracts listed above is 15 months.

In addition to including the gross assets and liabilities related to the Company's share of oil and gas production, the above tables and the accompanying consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner. The accompanying consolidated balance sheets include the negative fair value of derivatives and a corresponding receivable from the Partnerships of $5,351,500 as of December 31, 2005 and $1,418,000 as of December 31, 2004. In addition to the short-term fair value of derivatives shown on the accompanying consolidated balance sheets there are long-term assets and long-term liabilities which total to a net long-term liability of approximately $1,323,100 as of December 31, 2005 and which total a net long-term asset of approximately $1,248,000 as of December 2004, respectively related to the fair value of derivatives included in accompanying balance sheets.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults during the years ended December 31, 2005, 2004 and 2003.

The average NYMEX closing prices for natural gas for the years 2005, 2004, and 2003 were $8.62 Mmbtu, $6.14 Mmbtu, and $5.39 Mmbtu. The average NYMEX closing prices for oil for the years 2005, 2004 and 2003 were $55.34 bbl, $41.44 bbl and $30.98 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.

Disclosure of Limitations

Because the information above incorporates only those exposures that exist at December 31, 2005, it does not consider those exposures or positions which could arise after that date. As a result, the Company's ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, the Company's hedging strategies at the time, and interest rates and commodity prices at the time.

Item 8. Financial Statements and Supplementary Data

The response to this Item is set forth herein in a separate section of this Report, beginning on Page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

**Item 9A.** *Controls and Procedures*

**(a) Evaluation of Disclosure Controls and Procedures**

The Company has evaluated, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, President and Chief Financial Officer, the effectiveness of the design and operations of the Company's disclosure controls and procedures pursuant to Securities Exchange Act of 1934, as amended (the Exchange Act) Rules 13a-15(e) and 15-d–15(e) as of December 31, 2005. In the course of the evaluation, the Company considered the material weaknesses in the Company's internal control over financial reporting and other internal control matters discussed below and has concluded that the Company did not maintain effective disclosure controls and procedures as of December 31, 2005.

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

There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the most recent fiscal quarter that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting, except for changes in the fourth quarter of 2005 as noted below.

- The Company has increased the Company's technical expertise through development of training programs and acquiring accounting research software during the fourth quarter of 2005. Training will be on-going, however programs provided during 2005 included oil and gas accounting, general accounting and SEC financial reporting.

- The Company has enhanced the documentation of the Company's policies and procedures and related templates and analyses that support the Company's application of accounting principles in the several areas, including derivative accounting, oil and gas properties, and asset retirement obligations during the fourth quarter of 2005.

In addition, during the third quarter of fiscal 2005 and subsequently in 2006 the Company made the following changes and remediation:

At the direction of the Company's board of directors and audit committee, the Company has spent and continues to spend a significant amount of time and resources to improve the Company's control environment. The Company is committed to instilling strong internal control policies and procedures and ensuring that the "tone at the top" fully supports accuracy and completeness in all financial reporting. In support of this position, the Company's progress toward improving internal control over financial reporting has been openly communicated with the Company's Audit Committee, and the Company has undertaken to improve the design and effectiveness of the Company's internal control over financial reporting. The initiatives developed by the Company were both organizational and process focused. Organizational changes made during 2005 and through the date of this filing include, among others:

- The Company has enhanced the corporate accounting and reporting functions in the third quarter of 2005 by creating and filling several new positions with professionals highly experienced in oil and gas accounting. Two new professionals hold degrees in accounting and are Certified Public Accountants. One additional Certified Public Accountant was hired in early 2006, and a financial reporting director will be hired during 2006.

- The Company engaged a team of highly experienced advisors in early 2006 to assist with various accounting research, projects and monitoring activities. They assist the Company with accounting and reporting issues including, but not limited to, derivatives, oil and gas activities, new accounting standards or rules, SEC reporting and on-going monitoring of changes that may impact the Company's application of accounting principles.

- The Company has strengthened its Sarbanes-Oxley Act Section 404 compliance department through the addition of a leadership position and other experienced resources in the third quarter of 2005. The Company believes the strengthening of this department will significantly improve the design, effectiveness and monitoring of internal control over financial reporting.

The Company has also implemented or is planning to implement several process changes to improve the documentation supporting certain accounting and reporting activities as well as to improve the documentation of the Company's application of accounting principles.

- The Company has evaluated and selected a third-party integrated oil and gas accounting software system, which the Company plans to implement during 2006.

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

**(c) Management’s Report on Internal Control Over Financial Reporting**

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as that term is defined under Rule 13a-15(f) promulgated under the Exchange Act. In order to evaluate the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, as required by Section 404 of the Sarbanes-Oxley Act of 2002, management conducted an assessment, including testing, using the criteria set forth in Internal Control – Integrated Framework issued by the committee of Sponsoring Organization of the Treadway Commission (the “COSO Framework”). Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or the degree of compliance with policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The Company's assessment as of December 31, 2005, identified the following material weaknesses:

The Company did not have effective policies and procedures, and was not adequately staffed with accounting personnel possessing an appropriate level of technical expertise in U.S. generally accepted accounting principles, as further described below:

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

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

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

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

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

Management has concluded that, as a result of the material weaknesses noted above, the Company did not maintain effective internal control over financial reporting as of December 31, 2005 based on criteria set forth in the COSO Framework.

The Company’s independent registered public accounting firm, KPMG LLP, has issued an audit report on management’s assessment of the Company's internal control over financial reporting as of December 31, 2005. Their report follows this section of the Form 10-K.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Petroleum Development Corporation:

We have audited management’s assessment, included in the accompanying Management’s Report on Internal Control Over Financial Reporting (Item 9A(c)), that Petroleum Development Corporation (the Company) did not maintain effective internal control over financial reporting as of December 31, 2005 because of the effect of the material weaknesses identified in management's assessment based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management’s assessment and an opinion on the effectiveness of the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management’s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. Management has identified and included in its assessment the following material weaknesses as of December 31, 2005:

The Company did not have effective policies and procedures, and was not adequately staffed with accounting personnel possessing an appropriate level of technical expertise in U.S. generally accepted accounting principles, as further described below:

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

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

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

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

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2005. The aforementioned material weaknesses were considered in determining the nature, timing and extent of audit tests applied in our audit of the 2005 consolidated financial statements, and this report does not affect our report dated May 24, 2006, which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, management's assessment that Petroleum Development Corporation did not maintain effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, Petroleum Development Corporation did not maintain effective internal control over financial reporting as of December 31, 2005, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

KPMG LLP
Pittsburgh, Pennsylvania
May 24, 2006

Item 9B. Other Information

None.

## PART III

Item 10. Directors and Executive Officers of the Company

Directors and Executive Officers of the Company

The executive officers and directors of the Company, their principal occupations for the past five years and additional information are set forth below:

| Name | Age | Positions and Offices Held | Held Current Position Since |
|---|---|---|---|
| Steven R. Williams | 55 | Chairman and Chief Executive Officer, | January 2004 |
| | | and Director | March 1983 |
| Thomas E. Riley | 53 | President | December 2004 |
| | | Director | January 2004 |
| Darwin L. Stump | 51 | Chief Financial Officer and Treasurer | November 2003 |
| Eric R. Stearns | 48 | Executive Vice President Exploration and Production | December 2005 |
| Gregory A. Morgan | 47 | Secretary | September 2004 |
| Vincent F. D'Annunzio | 54 | Director | February 1989 |
| Jeffrey C. Swoveland | 51 | Director | March 1991 |
| Donald B. Nestor | 57 | Director | March 2000 |
| Kimberly Luff Wakim | 47 | Director | January 2003 |
| David C. Parke | 39 | Director | November 2003 |

Steven R. Williams was elected Chairman and Chief Executive Officer in January 2004. Mr. Williams served as President from March 1983 until December 2004 and has been a Director of the Company since March 1983.

Thomas E. Riley was elected Director in January 2004 by the Board of Directors and assumed the position of President in December 2004. Previously Mr. Riley was appointed Executive Vice President of Production, Natural Gas Marketing and Business Development in November 2003. Prior thereto, Mr. Riley served as Vice President Gas Marketing and Acquisitions of the Company since April 1996. Prior to joining the Company, Mr. Riley was president of Riley Natural Gas Company, a natural gas marketing company which the Company acquired in April 1996.

Darwin L. Stump was appointed Chief Financial Officer and Treasurer in November 2003. Mr. Stump has been an officer of the Company since April 1995 and held the position of Corporate Controller since 1980. Mr. Stump, a CPA, was a senior accountant with Main Hurdman, Certified Public Accountants prior to joining the Company.

Eric R. Stearns was appointed Executive Vice President of Exploration and Production in December 2005. Prior to that he was Executive Vice President of Exploration and Development since November 2003, having previously served as Vice President of Exploration and Development since April 1995. Mr. Stearns joined the Company as a geologist in 1985 after working for Hywell, Incorporated and for Petroleum Consultants.

Gregory A. Morgan has been a member of the law firm of Young, Morgan & Cann, Clarksburg, West Virginia since 1986. Mr. Morgan is not active in the day-to-day business of the Company, but his law firm provides legal services to the Company.

Vincent F. D'Annunzio has served as president of Beverage Distributors, Inc. located in Clarksburg, West Virginia since 1985.

Jeffrey C. Swoveland has served as Chief Financial Officer of Body Media since September, 2000. Prior thereto, Mr. Swoveland was Vice President-Finance and Treasurer of Equitable Resources, Inc. since 1994.

Donald B. Nestor is a Certified Public Accountant and a Partner in the CPA firm of Toothman Rice, P.L.L.C. and is in charge of the firm's Buckhannon, West Virginia office. Mr. Nestor has served in that capacity since 1975.

Kimberly Luff Wakim, an Attorney and Certified Public Accountant, is a Partner with the law firm Thorp, Reed & Armstrong LLP. Ms. Wakim joined Thorp Reed & Armstrong LLP in 1990.

David C. Parke was elected Director by the Board of Directors in November 2003. In 2003, Mr. Parke joined Mufson/Howe/Hunter & Company LLC, an investment banking firm as a founder and Director. From 1992-2003, Mr. Parke was with the corporate finance department of Investec, Inc. and its predecessor Pennsylvania Merchant Group Ltd., investment banking companies. Prior to joining Pennsylvania Merchant Group, Mr. Parke served in the corporate finance departments of Wheat First Butcher & Singer, now part of Wachovia Securities, and Legg Mason, Inc.

The Company's By-Laws provide that the directors of the Company shall be divided into three classes and that, at each annual meeting of stockholders of the Company, successors to the class of directors whose term expires at the annual meeting will be elected for a three-year term. The classes are staggered so that the term of one class expires each year. Mr. Williams, Mr. Nestor and Ms. Wakim are members of the class whose term expires in 2006. Mr. D’Annunzio and Mr. Riley are members of the class whose term expires in 2007. Mr. Swoveland and Mr. Parke are members of the class whose term expires in 2008. There is no family relationship between any director or executive officer and any other director or executive officer of the Company. There are no arrangements or understandings between any director or officer and any other person pursuant to which the person was selected as an officer.

On January 24, 2003, the Company adopted a Code of Business Conduct and Ethics Policy meeting the specified standards applicable to the Chief Executive Officer and Chief Financial Officer. The policy also covers all the corporate officers. The policy is posted on the Company's website at www.petd.com. The Company will provide a copy of the Code to any person, without charge, upon request to the Company’s Secretary at the Company’s principal executive offices or by telephone at 800-624-3821.

The Company has determined that all of its directors, other than Messrs. Williams and Riley are independent under NASDAQ rule 4200.

The Audit Committee of the Board of Directors is comprised entirely of independent directors as defined by the NASDAQ rule 4200(a)(15). Donald B. Nestor, CPA, a partner in the certified public accounting firm of Toothman Rice PLLC, chairs the committee; other audit committee members are Mr. Jeffrey C. Swoveland and Ms. Kimberly Luff Wakim. The Board of Directors has determined that Mr. Nestor and the other Audit Committee members qualify as audit committee financial experts and are independent of management.

The Nominating and Governance and Compensation Committees are also comprised entirely of independent directors of the Company. Vincent F. D'Annunzio chairs the Nominating and Governance Committee, and David C. Parke chairs the Compensation Committee.

The independent directors conduct meetings without the presence of management at each scheduled Board meeting. Kimberly Luff Wakim serves as Chairperson of these meetings having been selected as lead independent director by the Board.

Shareholders wishing to communicate with the Board of Directors or a committee may do so by writing to the attention of the Board or Committee at the corporate headquarters or by emailing the Board at board@petd.com, with "Board" or appropriate committee in the subject line.

Item 11. Executive Compensation

Summary Compensation Table

The following table sets forth in summary form the compensation received during each of the Company's last three fiscal years by the Chief Executive Officer and by each other executive officer of the Company whose salary and bonus exceeded $100,000 in 2005 (the "Named Executives").

| | | Annual Compensation | | | Long Term Compensation | | |
|---|---|---|---|---|---|---|---|
| Name and Principal Position | Year | Salary($) | Bonus (1)($) | Other Annual Compen-sation($)(2) | Restricted Stock Awards ($)(3) | Securities underlying Options (#)(4) | All Other Compen-sation($)(5) |
| Steven R. Williams | 2005 | 318,000 | 271,597 | 11,886 | - | - | 146,666 |
| Chief Executive Officer | 2004 | 300,000 | 300,000 | 37,567 | 302,030 | 5,870 | 135,834 |
| and Director | 2003 | 166,485 | 1,312,385 | 6,241 | - | - | 101,726 |
| Thomas E. Riley | 2005 | 252,000 | 141,135 | 4,638 | - | - | 106,666 |
| President | 2004 | 240,000 | 140,000 | 5,624 | 200,239 | 3,890 | 100,834 |
| and Director | 2003 | 153,400(6) | 121,370 | 1,565 | - | - | 21,726 |
| Eric R. Stearns | 2005 | 231,000 | 129,374 | 11,406 | - | - | 102,666 |
| Executive Vice President | 2004 | 220,000 | 140,000 | 9,678 | 188,796 | 3,670 | 97,834 |
| | 2003 | 132,567(6) | 121,370 | 1,084 | - | - | 20,726 |
| Darwin L. Stump | 2005 | 210,000 | 98,713 | 9,398 | - | - | 106,666 |
| Chief Financial Officer | 2004 | 200,000 | 140,000 | 12,773 | 177,577 | 3,450 | 97,834 |
| and Treasurer | 2003 | 112,733(6) | 121,370 | 1,074 | - | - | 12,777 |

(1) Includes bonuses earned in the reported fiscal year and paid in the following fiscal year.

(2) Amounts disclosed in this column consist of use of a company vehicle, life insurance, disability insurance, and medical reimbursement as provided for in the Named Executive's employment contract.

(3) Amounts disclosed in this column consist of the value of restricted stock awards based upon the closing price of our common stock on the date of grant which was $37.15 on December 13, 2004. During 2004 the number of shares awarded to Messrs. Williams, Riley, Stearns and Stump amounted to 8,130, 5,390, 5,080 and 4,780 shares, respectively. These shares vest in four equal installments on the first, second, third and fourth anniversaries of the grant date.

(4) Amounts in this column represent the number of options granted on December 13, 2004 to the named individuals. The fair value of these options at date of grant was $16.75 using the Black-Scholes option pricing model with an exercise price of $37.15. These options vest in four equal installments on the first, second, third and fourth anniversaries of the grant date.

(5) This amount includes contributions made by the Company under the Company's Employee Profit Sharing Plan and 401(k) plan. In 2005, 2004 and 2003 the Company contributed $420,000, $300,000 and $250,000, respectively, to the Employee Profit Sharing Plan. Of the contributions for 2005 and 2004, Messrs. Williams, Riley, Stearns and Stump were each credited $13,666 and $9,834, respectively. Of the contributions for 2003, Messrs., Williams, Riley and Stearns were each credited $9,726 and Mr. Stump was credited $8,634. The Company provided a matching of 401(k) contribution based upon all employees respective contributions. The total Company matching contributions were $450,653, $382,700 and $305,515 in 2005, 2004 and 2003. For 2005, Messrs. Williams, Riley and Stump were each credited with matching contributions of $18,000, Mr. Stearns was credited with a matching contribution of $14,000. For 2004, Messrs. Williams and Riley were each credited with matching contributions of $16,000, Messrs. Stearns and Stump were credited with matching contributions of $13,000. For 2003, Messrs. Williams and Riley were each credited with matching contributions of $12,000, Messrs. Stearns and Stump were credited with matching contributions of $11,000 and $4,143, respectively. This amount also includes retirement compensation for the named individuals which provides for an amount per year worked under their employment agreements for 10 years following their termination of service. The total amounts earned during 2005 and 2004 to be paid over the ten-year period following such individuals' termination amounted to $115,000 and $110,000, respectively for Mr. Williams, and $75,000 for Messrs. Riley, Stearns and Stump for each year. For 2003 such amount was $80,000 for Mr. Williams. See "Retirement Arrangements" discussed below for a description of these arrangements.

(6) This amount includes compensation for Messrs. Riley, Stearns and Stump earned during 2003 while each was an officer of the Company prior to becoming an Executive Officer in November 2003.

Aggregated Option Exercises in Last Fiscal Year and Fiscal Year-End Option Values

The following table provides certain information with respect to options exercised during 2005 by the persons named in the Summary Compensation Table under the Company's stock option plans, the number of options outstanding as of December 31, 2005 and the year-end value of such options, with respect to options granted pursuant to the Company's employee stock compensation plans.

| | Number of Shares Exercised | Value Realized ($)* | Number of Options at Year-end | | Value of Unexercised In-The-Money Options at Year-End(1)($) | |
|---|---|---|---|---|---|---|
| | | | Exercisable | Unexercisable | Exercisable | Unexercisable* |
| Steven R. Williams | - | - | 1,467 | 4,403 | - | - |
| Thomas E. Riley | - | - | 972 | 2,918 | - | - |
| Eric R. Stearns | - | - | 917 | 2,753 | - | - |
| Darwin L. Stump | - | - | 862 | 2,588 | - | - |

*Market value of the underlying securities at exercise or year-end, as applicable, minus the exercise price.

(1) On December 31, 2005, the closing sales price of the Common Stock was $33.34 per share; the exercise price of these options is $37.15 per share.

Employment and Other Agreements and Arrangements

The Company entered into employment agreements with Messrs. Williams, Riley, Stearns and Stump effective January 1, 2004. The initial term of the agreements is for two years and they are automatically extended for an additional 12 months beginning on the first anniversary of the effective date and on each successive anniversary unless either party cancels. The employment agreements provided for a base annual salary for Mr. Williams, Mr. Riley, Mr. Stearns and Mr. Stump in the amounts of $300,000, $240,000, $220,000 and $200,000, respectively for 2004. For 2005 the Compensation Committee established base salaries for Mr. Williams, Mr. Riley, Mr. Stearns and Mr. Stump in the amounts of $318,000, $252,000, $231,000 and $210,000, respectively. Each employment agreement provides for an annual performance bonus, based upon a combination of written objective criteria approved by the Compensation Committee, determined prior to the beginning of each calendar year and upon the discretion of the Compensation Committee. The maximum amounts of the entire annual performance bonus were $300,000 for Mr. Williams and $140,000 for Messrs. Riley, Stearns and Stump in 2004. Each of the executives earned the maximum bonus in 2004. For 2005 the Compensation Committee set maximum annual performance amounts for Mr. Williams, Mr. Riley, Mr. Stearns and Mr. Stump of $413,400, $201,600, $184,800 and $168,000, respectively. Bonus earned in 2005 was $271,597 for Mr. Williams, $141,135 for Mr. Riley, $129,374 for Mr. Stearns and $98,713 for Mr. Stump.

In the event of a change in control of the Company, each Named Executive has the right to elect to terminate his employment under his employment agreement and receive severance compensation equal to three times the sum of 1) his highest base salary in the previous two years of employment plus 2) highest bonus paid to the named Executive during the same two year period.

Each employment agreement contains a standard non-disclosure covenant. Each employment agreement also provides that the Named Executive is prohibited during the term of his employment and for a period of one year following his termination from engaging in any business that is competitive with the Company's oil and gas drilling business.

Retirement Arrangements

The Company provides supplemental retirement benefits under terms of the various employment agreements with the Company's executive officers. The January 1, 2004 agreements provide for retirement benefits for each executive officer for a ten year period following the date of termination of service. During the life of each respective agreement, $110,000 for Mr. Williams and $75,000 for each of Messrs. Riley, Stearns and Stump are allocated yearly to their respective retirement account. The allocated amounts are accumulated over the life of the respective agreements. Following termination of service the aggregate fund will be disbursed to the individual officer in equal installments over ten years. Mr. Williams' agreement has an escalator provision which provides an increase in the annual contribution allocated to his retirement amount equal to $5,000 per year. In 2004, the allocation to Mr. Williams supplemental retirement account was $110,000; in 2005, the allocation increased to $115,000 for his account; in 2006, the allocation will increase to $120,000. At December 31, 2005, the executive officers had accumulated the following amounts in their respective retirement accounts, Mr. Williams $225,000; Mr. Riley $150,000; Mr. Stearns $150,000 and Mr. Stump $150,000. These accounts will continue to accumulate retirement funds during the terms of the respective employment agreements.

Under his previous employment agreement, Mr. Williams also earned supplemental retirement benefits. The prior agreement requires the Company to pay Mr. Williams an annual sum of $40,000 per year for the ten year period following his retirement from the Company (an aggregate of $400,000), in addition to benefit discussed above. This benefit was fully vested on December 31, 2003.

Stock Option Plans

Under the Company's incentive stock option plans, options to purchase shares of Common Stock of the Company may be granted to certain officers and key employees of the Company, which options are intended to qualify as incentive stock options under the provisions of the Internal Revenue Code. The options may be exercised six months after the date of grant. Options will expire ten years from the date of grant if not exercised. A dissolution or liquidation of the Company or a merger or consolidation in which the Company is not the surviving corporation will cause each outstanding option to terminate, provided that each optionee, in such event, will have the right immediately prior to said dissolution or liquidation or merger or consolidation to exercise his option in whole or in part without regard to any installment vesting provisions with respect to such options. No additional options may be granted under these earlier plans.

As approved by the shareholders at the annual meeting in 2004, the Company has a Long-Term Equity Compensation Plan which allows for the awarding of Non-qualified stock options, Incentive Stock Options, Stock Appreciation Rights, Restricted Stock, Performance shares and Performance units. The number of shares allocated to this plan is 750,000 shares. During 2004, a total of 23,380 shares of restricted stock and 16,880 options were granted to the executives named previously. As of April 30, 2006, 664,075 shares remain in the plan, for future grants.

Key-Man Life Insurance

The Company maintains key-man life insurance policies on the life of Mr. Williams in the amount of $4.0 million, and in the amount of $1.0 million for Messrs. Riley, Stearns and Stump. The Company is the beneficiary of each policy.

Employee 401(k) and Profit Sharing Plan

In 1987, the Company established a retirement plan qualified under Section 401(k) of the Internal Revenue Code. The plan is funded by employee contributions and a company matching contribution. Administrative costs of the plan are borne by the Company. The employees choose from eight investment programs and, therefore, the amount of an individual's plan assets depends on the amount of their contributions and the performance by their chosen investments.

In 1992, the Company began a Profit Sharing Retirement plan to supplement the 401(k) Plan. Contributions are dependent on corporate profitability and are at the discretion of the Board of Directors of the Company. The Company filed and qualified the plan with the Internal Revenue Service.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth certain information regarding ownership of the Company's Common Stock as of April 30, 2006 by (a) each person known by the Company to own beneficially more than 5% of the outstanding shares of Common Stock; (b) each director of the Company; (c) each Named Executive; (d) all directors and executive officers as a group.

| | Beneficial Ownership (1) | |
|---|---|---|
| Name and Address | Number | Percent |
| Barclays Global Investors, NA<br>45 Fremont Street<br>San Francisco, CA 94105 | 2,477,121 (2) | 15.40% |
| Fidelity Management<br>82 Devonshire Street<br>Boston, MA 02109 | 2,415,600 (3) | 15.00% |
| Kayne Anderson Rudnick<br>Investment Management LLC<br>1800 Avenue of the Stars 2nd Floor<br>Los Angeles, CA 90067 | 1,281,289 (4) | 8.00% |
| Steinberg Asset Management LLC<br>12 East 49th Street<br>New York, NY 10017 | 1,104,781 (5) | 6.90% |
| Steven R. Williams<br>103 East Main Street<br>Bridgeport, WV 26330 | 421,101 (6) | 2.60% |
| Thomas E. Riley<br>103 E. Main Street<br>Bridgeport, WV 26330 | 109,700 (7) | * |
| Eric R. Stearns<br>103 E. Main Street<br>Bridgeport, WV 26330 | 61,438 (8) | * |
| Darwin L. Stump<br>103 E. Main Street<br>Bridgeport, WV 26330 | 30,473 (9) | * |
| Vincent F. D'Annunzio | 18,646 | * |
| Jeffrey C. Swoveland | 13,721 | * |
| Donald B. Nestor | 2,522 | * |
| Kimberly Luff Wakim | 2,965 | * |
| David C. Parke | 2,450 | * |
| All directors and executive officers as a group (9 persons) | 663,016 | 4.10% |

* Less than 1%

(1) Includes shares over which the person currently holds or shares voting or investment power. Unless otherwise indicated in the footnotes to this table, the persons named in this table have sole voting and investment power with respect to the shares beneficially owned.
(2) According to the Schedule 13G filed by Barclay Global Investors, NA with the Securities and Exchange Commission on January 26, 2006.
(3) According to the Schedule 13G filed by Fidelity Management with the Securities and Exchange Commission on January 10, 2006.
(4) According to Schedule 13G filed by Kayne Anderson Rudnick Investment Management, LLC with the Securities and Exchange Commission on February 6, 2006.
(5) According to the Schedule 13F-HR filed by Steinberg Asset Management, LLC with the Securities and Exchange Commission on April 17, 2006.
(6) Mr. Williams: includes 1,467 shares subject to options exercisable within 60 days of April 30, 2006.
(7) Mr. Riley: includes 972 shares subject to options exercisable within 60 days of April 30, 2006.
(8) Mr. Stearns: includes 917 shares subject to options exercisable within 60 days of April 30, 2006.
(9) Mr. Stump: includes 862 shares subject to options exercisable within 60 days of April 30, 2006.

*Section 16(a) Beneficial Ownership Reporting Compliance*

Section 16(a) of the Exchange Act requires the Company's officers and directors, and persons who own more than 10% of a Company's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission. Officers, directors and holders of more than 10% of the Common Stock are required by regulations promulgated by the Commission pursuant to the Exchange Act to furnish the Company with copies of all Section 16(a) forms they file. The Company assists officers and directors, and will assist beneficial owners, if any, of more than 10% of the Common Stock, in complying with the reporting requirements of Section 16(a) of the Exchange Act.

Based solely on its review of the copies of such forms received by it, the Company believes that since January 1, 2005, all Section 16(a) filing requirements applicable to its directors, officers and greater than 10% beneficial owners were met.

The Company has the following common stock options outstanding under the stock option plans authorized for issuance:

Equity Compensation Plan Information
April 30, 2006

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 94,234 | $18.82 | 664,075 |
| Equity compensation plans not approved by security holders | 0 | 0 | 0 |
| Total | 94,234 | $18.82 | 664,075 |

Item 13. Certain Relationships and Related Transactions

During the year ended December 31, 2005, there was no transaction or series of transactions to which we were or are a party in which the amount involved exceeded or exceeds $60,000 and in which any director, executive officer, holder of more than 5% of our common stock or any member of the immediate family of any of the foregoing persons had or will have a direct or indirect material interest.

Item 14. Principal Accountant Fees and Services

KPMG Fees

The following table presents the aggregate fees billed to the Company by KPMG LLP (KPMG) for services in 2005 and 2004 as of March 31, 2006:

| | 2005 | 2004 |
|---|---|---|
| Audit Fees | $ 1,743,010 | $ 708,524 |
| Audit Related Fees | 140,977 | 309,127 |
| Total Audit and Audit Related Fees | $1,883,987 | $1,017,651 |
| Tax Fees | 0 | 4,000 |
| All Other Fees | 0 | 0 |
| Total Fees | $ 1,883,987 | $1,021,651 |

Audit Fees

The aggregate audit fees billed for professional services rendered by KPMG LLP for the audit of our annual financial statements and the audit of the Company's internal controls over financial reporting for the fiscal years ended December 31, 2005 and 2004, including reviews of the condensed financial statements included in our quarterly reports on Form 10-Q for the fiscal years ended December 31, 2005 and 2004, were $1,743,010 and $708,524.

Audit Related Fees

The aggregate of audit related fees relating to registration statements filed with the Securities and Exchange Commission amounted to $24,900 for the year ended December 31, 2004. Also included as audit related fees are the annual audits of the financial statements for the fiscal years ended December 31, 2005 and 2004 of sixty-five and sixty-two limited partnerships, respectively, for which the Company acts as managing general partner. The aggregate billings for those professional services was $284,227 for the year ended December 31, 2004, the services for the year ended December 31, 2005 have not been billed as of March 31, 2006. The total of audit related fees for the year ended December 31, 2005 was for due diligence services provided for a contemplated transaction.

Tax Fees

Tax Fees include tax compliance services for the fiscal year ended December 31, 2004 provided for the partnerships formed in such year for which the Company acts as managing general partner, in the amount of $4,000.

Pre-Approval Policies and Procedures

The Sarbanes-Oxley Act of 2002 requires that all services provided to the Company by its Independent Registered Public Accounting Firm be subject to pre-approval by the Audit Committee or authorized members of the Committee. The Audit Committee has adopted policies and procedures for pre-approval of all audit services and non-audit services to be provided by the Company's Independent Registered Public Accounting Firm. Services necessary to conduct the annual audit must be pre-approved by the Audit Committee annually at a meeting. Permissible non-audit services to be performed by the independent accountant may also be approved on an annual basis by the Audit Committee if they are of a recurring nature. Permissible non-audit services to be conducted by the independent accountant which are not eligible for annual pre-approval must be pre-approved individually by the full Audit Committee or by an authorized Audit Committee member. Actual fees incurred for all services performed by the independent accountant will be reported to the Audit Committee after the services are fully performed. The duties of the Committee are described in the Audit Committee Charter, which is available at the Company's website under Corporate Governance.

Item 15. Exhibits and Financial Statement Schedules

(a) (1) Financial Statements:
See Index to Financial Statements and Schedules on page F-1.

(2) Financial Statement Schedules:
See Index to Financial Statements and Schedules on page F-1.

Schedules and Financial Statements Omitted

All other financial statement schedules are omitted because they are not required, inapplicable, or the information is included in the Financial Statements or Notes thereto.

(3) Exhibits:
See Exhibits Index on page E-1.

CONFORMED COPY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

By /s/ Steven R. Williams
Steven R. Williams, Chairman

May 31, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

| Signature | Title | Date |
|---|---|---|
| /s/ Steven R. Williams<br>Steven R. Williams | Chairman, Chief Executive Officer and Director | May 31, 2006 |
| /s/ Darwin L. Stump<br>Darwin L. Stump | Chief Financial Officer and Treasurer<br>(principal financial and accounting officer) | May 31, 2006 |
| /s/ Thomas E. Riley<br>Thomas E. Riley | President and Director | May 31, 2006 |
| /s/ Donald B. Nestor<br>Donald B. Nestor | Director, Chairman of Audit Committee | May 31, 2006 |
| /s/ Vincent F. D'Annunzio<br>Vincent F. D'Annunzio | Director | May 31, 2006 |
| /s/ Jeffrey C. Swoveland<br>Jeffrey C. Swoveland | Director | May 31, 2006 |
| /s/ Kimberly Luff Wakim<br>Kimberly Luff Wakim | Director | May 31, 2006 |
| /s/ David C. Parke<br>David C. Parke | Director | May 31, 2006 |

Exhibits Index

(a) Exhibits

| Exhibit Name | Exhibit Number | Location |
|---|---|---|
| Articles of Incorporation | 3.1 | Incorporated by reference to Exhibit 3.1 to Form S-2 SEC File No. 333-36369 filed on September 25, 1997 |
| By Laws | 3.2 | Incorporated by reference to Exhibit 3.2 to Form 8-K SEC File No. 0-07246 filed on September 8, 2003 |
| Amended and restated Credit Agreement, dated as of November 4, 2005, Petroleum Development Corporation, as borrower, and JPMorgan Chase Bank, N.A. and BNP Paribas, as lenders. | 10.1 | Incorporated by reference to Exhibit 10.2 to Form 8-K dated November 4, 2005. |
| Employment Agreement with Steven R. Williams, Chief Executive Officer and Chairman, dated as of March 7, 2003 and amended December 29, 2005 | 10.2 | Incorporated by reference in Exhibit 10.2 to Form 10-K filed on March 7, 2003 and amended by reference of Form 8-K filed January 4, 2006 |
| Employment Agreement with Darwin L. Stump, Chief Financial Officer, dated as of January 5, 2004 and amended December 29, 2005 | 10.3 | Incorporated by reference to Exhibit 99.4 Form 8-K dated January 5, 2004 and Exhibit 99.4 to Form 8-K dated January 4, 2006 |
| Employment Agreement with Thomas E. Riley, President, dated as of January 5, 2004 and amended December 29, 2005 | 10.4 | Incorporated by reference to Exhibit 99.6 Form 8-K dated January 5, 2004 and Exhibit 99.2 to Form 8-K dated January 4, 2006 |
| Employment Agreement with Eric R. Stearns, Executive Vice President, dated as of January 5, 2004 and amended December 29, 2005 | 10.5 | Incorporated by reference to Exhibit 99.5 Form 8-K dated January 5, 2004 and Exhibit 99.3 to Form 8-K dated January 4, 2006. |
| 2005 Non-Employee Director Restricted Stock Plan | 10.6 | Incorporated by reference to Exhibit 99.1 to Form S-8, SEC file No. 333-126444 filed on July 7, 2005 |
| 2004 Long-Term Equity Compensation Plan | 10.7 | Incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-118215, filed on August 13, 2004 |
| Non-Employee Director Deferred Compensation Plan | 10.8 | Incorporated by reference Exhibit 99.1 to Form S-8, SEC File No. 333-118222, filed on August 13, 2004 |
| 1999 Incentive Stock Option and Non-Qualified Stock | 10.9 | Incorporated by reference to Exhibit 99.1 to form S-8, SEC File No. 333-111825, filed on January 9, 2004 |
| 1997 Employee Incentive Stock Option Plan | 10.10 | Incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-111824, filed on January 9, 2004 |
| Tom Carpenter Employment Agreement Stock Option Plan | 10.11 | Incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-111823, filed on January 9, 2004 |
| Code of Business Conduct and Ethics | 14 | Incorporated by reference to Exhibit 3.1 to Form 10-K for the year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003 |
| Subsidiaries | 21 | Riley Natural Gas Company, a West Virginia Corporation |
| | 21 | PDC Securities Incorporated, a West Virginia Corporation |
| Consent of Independent Registered Public Accounting Firm | 23.1 | Filed herewith. |
| Consent of Independent Petroleum Engineers | 23.2 | Filed herewith. |
| Consent of Independent Petroleum Engineers | 23.3 | Filed herewith |

| | | |
|---|---|---|
| Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer | 31.1 | Filed herewith. |
| Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer | 31.2 | Filed herewith. |
| Title 18 U.S.C. Section 1350 (Section 906 of Sarbanes-Oxley Act of 2002) Certifications by Chief Executive Officer and Chief Financial Officer | 32.1 | Filed herewith. |

## GLOSSARY OF TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this Form 10-K.

*Bbl*. One barrel, or 42 U.S. gallons of liquid volume.

*Bcf*. One billion cubic feet.

*Bcfe*. One billion cubic feet of natural gas equivalents.

*Completion*. The installation of permanent equipment for the production of oil or gas.

*Credit Facility*. A line of credit provided by a group of banks, secured by oil and gas properties.

*DD&A*. Refers to depreciation, depletion and amortization of the Company's property and equipment.

*Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

*Dry hole*. A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil or gas well.

*Exploratory well*. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

*Extensions and discoveries*. As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

*Gross acres or wells*. Refers to the total acres or wells in which the Company has a working interest.

*Horizontal drilling*. A drilling technique that permits the operator to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

*MBbls*. One thousand barrels.

*Mcf*. One thousand cubic feet.

*Mcfe*. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 Mcf for each barrel of oil, which reflects the relative energy content.

*MMbtu*. One million British thermal units. One British thermal unit is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

*MMcf*. One million cubic feet.

*MMcfe*. One million cubic feet of natural gas equivalents.

*Natural gas liquids*. Liquid hydrocarbons that have been extracted from natural gas, such as ethane, propane, butane and natural gasoline.

*Net acres or wells*. Refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by the Company.

*Net production*. Oil and gas production that is owned by the Company, less royalties and production due others.

*NYMEX*. New York Mercantile Exchange, the exchange on which commodities, including crude oil and natural gas futures contracts, are traded.

*Oil*. Crude oil or condensate.

*Operator*. The individual or company responsible for the exploration, development and production of an oil or gas well or lease.

*Present value of proved reserves*. The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, (ii) nonproperty related expenses such as general and administrative expenses, debt service and future income tax expense, or (iii) depreciation, depletion and amortization.

*Proved developed nonproducing reserves*. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

*Proved developed producing reserves.* Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

*Proved developed reserves.* The combination of proved developed producing and proved developed nonproducing reserves.

*Proved reserves*. The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

*Proved undeveloped reserves (PUD).* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

*Royalty*. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

*SEC*. The United States Securities and Exchange Commission.

*Standardized measure of discounted future net cash flows*. Present value of proved reserves, as adjusted to give effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, and (ii) estimated future income taxes.

*Undeveloped acreage*. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether such acreage contains proved reserves.

*Working interest.* An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest is entitled will be smaller than the share of costs that the working interest owner is required to bear to the extent of any royalty burden.

*Workover*. Operations on a producing well to restore or increase production.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Index to Financial Statements and Financial Statement Schedule

## Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Petroleum Development Corporation:

We have audited the accompanying consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2005. In connection with our audits of the consolidated financial statements, we also have audited the related financial statement schedule II. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U. S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 22 to the consolidated financial statements, the Company restated its 2004 and 2003 consolidated financial statements.

As discussed in Note 1 to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, in 2003.

We also have audited, in accordance with the standards of Public Company Accounting Oversight Board (United States), the effectiveness of Petroleum Development Corporation's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated May 15, 2006, expressed an unqualified opinion on management's assessment of, and an adverse opinion on the effective operation of, internal control over financial reporting as of December 31, 2005.

KPMG LLP
Pittsburgh, Pennsylvania
May 24, 2006

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2005 and 2004

| Assets | 2005 | 2004 |
|---|---|---|
| Current assets: | | |
| Cash and cash equivalents | $ 90,110,100 | $ 77,070,400 |
| Restricted cash | 1,500,600 | 664,900 |
| Accounts receivable | 49,779,500 | 33,834,700 |
| Accounts receivable affiliates | 7,233,800 | 2,230,600 |
| Inventories | 5,054,900 | 1,657,300 |
| Fair value of derivatives | 10,381,800 | 3,266,100 |
| Other current assets | 4,640,500 | 6,612,800 |
| Total current assets | 168,701,200 | 125,336,800 |
| Properties and equipment: | | |
| Oil and gas properties (successful efforts accounting method) | 365,379,600 | 282,837,200 |
| Pipelines | 11,511,600 | 9,515,000 |
| Transportation and other equipment | 6,382,800 | 4,453,700 |
| Land and buildings | 3,980,800 | 2,942,800 |
| Construction in progress | 1,509,300 | - |
| | 388,764,100 | 299,748,700 |
| Less accumulated depreciation, depletion and amortization | 111,605,900 | 92,165,400 |
| | 277,158,200 | 207,583,300 |
| Other assets | 3,225,500 | 2,108,200 |
| Total Assets | $ 449,084,900 | $ 335,028,300 |

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2005 and 2004

| Liabilities and Stockholders' Equity | 2005 | 2004 |
|---|---|---|
| Current liabilities: | | |
| Accounts payable | $ 65,004,100 | $ 43,182,900 |
| Production tax liability | 30,144,500 | 17,510,500 |
| Fair value of derivatives | 18,424,400 | 6,716,400 |
| Other accrued expenses | 4,140,500 | 2,286,800 |
| Advances for future drilling contracts | 49,999,400 | 42,497,300 |
| Federal and state income taxes payable | 8,473,200 | - |
| Funds held for future distribution | 18,346,300 | 12,911,800 |
| Total current liabilities | 194,532,400 | 125,105,700 |
| Long-term debt | 24,000,000 | 21,000,000 |
| Other liabilities | 7,115,500 | 3,927,500 |
| Deferred income taxes | 26,888,500 | 22,976,300 |
| Asset retirement obligation | 8,283,200 | 7,998,200 |
| Total liabilities | 260,819,600 | 181,007,700 |
| Commitments and contingencies (Note 10) | | |
| Stockholders' equity: | | |
| Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 16,281,923 and 16,589,824 shares | 162,800 | 165,800 |
| Additional paid-in capital | 30,422,900 | 37,684,300 |
| Retained earnings | 158,504,200 | 117,052,500 |
| Unamortized stock award | (824,600) | (882,000) |
| Total stockholders' equity | 188,265,300 | 154,020,600 |
| Total Liabilities and Stockholders' Equity | $ 449,084,900 | $ 335,028,300 |

See accompanying Notes to Consolidated Financial Statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Income

Years Ended December 31, 2005, 2004, and 2003

| | 2005 | 2004 (Restated) | 2003 (Restated) |
|---|---|---|---|
| Revenues: | | | |
| Oil and gas well drilling operations | $ 99,962,900 | $ 94,076,000 | $ 57,509,600 |
| Gas sales from marketing activities | 121,104,100 | 94,626,800 | 73,131,700 |
| Oil and gas sales | 102,559,200 | 69,492,100 | 48,393,800 |
| Well operations and pipeline income | 8,759,600 | 7,676,900 | 6,907,100 |
| Other income | 10,747,300 | 1,880,700 | 3,528,500 |
| Total revenues | 343,133,100 | 267,752,500 | 189,470,700 |
| Costs and expenses: | | | |
| Cost of oil and gas well drilling operations | 88,184,900 | 77,696,200 | 46,945,900 |
| Cost of gas marketing activities | 119,643,700 | 92,881,200 | 72,361,400 |
| Oil and gas production and well operations costs | 19,934,700 | 17,277,200 | 13,251,300 |
| Exploratory dry hole costs | 11,115,100 | - | - |
| General and administrative expenses | 6,960,300 | 4,505,600 | 4,974,400 |
| Depreciation, depletion and amortization | 21,116,200 | 18,155,900 | 15,312,800 |
| Total costs and expenses | 266,954,900 | 210,516,100 | 152,845,800 |
| Income from operations | 76,178,200 | 57,236,400 | 36,624,900 |
| Interest expense | 682,300 | 673,700 | 1,195,300 |
| Oil and gas price risk management loss, net | 9,368,100 | 3,084,600 | 812,400 |
| Income before income taxes and cumulative effect of change in accounting principle | 66,127,800 | 53,478,100 | 34,617,200 |
| Income taxes | 24,676,100 | 20,250,500 | 11,933,500 |
| Net income before cumulative effect of change in accounting principle | 41,451,700 | 33,227,600 | 22,683,700 |
| Cumulative effect of change in accounting principle (net of taxes of $1,392,000) | - | - | (2,271,300) |
| Net income | $ 41,451,700 | $ 33,227,600 | $ 20,412,400 |
| Basic earnings per common share before accounting change | $ 2.53 | $ 2.05 | $ 1.45 |
| Cumulative effect of change in accounting principle | - | - | $ (0.15) |
| Basic earnings per common share | $ 2.53 | $ 2.05 | $ 1.30 |
| Diluted earnings per share before accounting change | $ 2.52 | $ 2.00 | $ 1.39 |
| Cumulative effect of change in accounting principle | - | - | $ (0.14) |
| Diluted earnings per common and common equivalent share | $ 2.52 | $ 2.00 | $ 1.25 |

See accompanying Notes to Consolidated Financial Statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 2005, 2004, and 2003

| | Common Stock Issued | | | | | | |
|---|---|---|---|---|---|---|---|
| | Number of Shares | Amount | Additional Paid-In-Capital | Retained Earnings | Treasury Stock at Cost (Restated) | Unamortized Stock Award | Total |
| Balance, December 31, 2002 | 15,734,767 | $ 157,300 | $ 29,340,500 | $ 63,412,500 | $ - | $ (23,700) | $ 92,886,600 |
| Amortization of stock award | - | - | - | - | - | 8,900 | 8,900 |
| Repurchase of treasury stock | - | - | - | - | (748,700) | - | (748,700) |
| Treasury stock retirement | (106,334) | (1,100) | (747,600) | - | 748,700 | - | - |
| Net income | - | - | - | 20,412,400 | - | - | 20,412,400 |
| Balance, December 31, 2003 | 15,628,433 | 156,200 | 28,592,900 | 83,824,900 | - | (14,800) | 112,559,200 |
| Issuance of common stock | | | | | | | |
| Exercise of employee stock options | 1,100,000 | 11,000 | 4,981,700 | - | - | - | 4,992,700 |
| Stock award | 23,380 | 200 | 870,700 | - | - | (870,900) | - |
| Amortization of stock award | - | - | - | - | - | 3,700 | 3,700 |
| Repurchase of treasury stock | - | - | - | - | (4,157,400) | - | (4,157,400) |
| Treasury stock retirement | (161,989) | (1,600) | (4,155,800) | - | 4,157,400 | - | - |
| Income tax benefit from the exercise of stock options | - | - | 7,394,800 | - | - | - | 7,394,800 |
| Net income | - | - | - | 33,227,600 | - | - | 33,227,600 |
| Balance, December 31, 2004 | 16,589,824 | 165,800 | 37,684,300 | 117,052,500 | - | (882,000) | 154,020,600 |
| Issuance of common stock | | | | | | | |
| Exercise of employee stock options | 3,000 | 100 | 11,500 | - | - | - | 11,600 |
| Stock award | 20,895 | 200 | 602,600 | - | - | (602,800) | - |
| Amortization of stock award | - | - | - | - | - | 660,200 | 660,200 |
| Repurchase of treasury stock | - | - | - | - | (7,878,800) | - | (7,878,800) |
| Treasury stock retirement | (331,796) | (3,300) | (7,875,500) | - | 7,878,800 | | |
| Net income | - | - | - | 41,451,700 | - | - | 41,451,700 |
| Balance, December 31, 2005 | 16,281,923 | $ 162,800 | $ 30,422,900 | $ 158,504,200 | $ - | $ (824,600) | $188,265,300 |

See accompanying Notes to Consolidated Financial Statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years Ended December 31, 2005, 2004, and 2003

| Cash flows from operating activities: | 2005 | 2004 | 2003 |
|---|---|---|---|
| Net income | $41,451,700 | $33,227,600 | $20,412,400 |
| Adjustment to reconcile net income to cash provided by operating activities: | | | |
| Deferred income taxes | 3,350,600 | 9,887,300 | 8,462,300 |
| Depreciation, depletion and amortization | 21,116,200 | 18,155,900 | 15,312,800 |
| Accretion of asset retirement obligation | 465,200 | 436,000 | 379,200 |
| Exploratory dry hole costs | 11,115,100 | - | - |
| Unrealized loss (gain) on derivative transactions | 3,225,900 | 535,200 | (1,110,200) |
| Cumulative effect of change in accounting principle | - | - | 2,271,300 |
| Gain from sale of assets | (7,875,800) | (32,000) | (202,500) |
| Expired and abandoned leases | 47,600 | 300,800 | 1,383,000 |
| Amortization of stock award | 660,200 | 3,700 | 8,900 |
| Change in assets and liabilities: | | | |
| Increase in accounts receivable | (11,276,400) | (10,492,600) | (7,197,800) |
| (Increase) decrease in accounts receivable affiliates | (5,003,200) | (343,200) | 10,700 |
| (Increase) decrease in restricted cash | (835,700) | 1,201,500 | 894,100 |
| (Increase) decrease in inventories | (3,397,600) | 357,000 | (1,383,600) |
| Decrease (increase) in other current assets | 3,482,100 | 4,776,200 | (1,095,900) |
| (Increase) decrease in other assets | (651,600) | (48,800) | 1,696,200 |
| Increase in production tax liability | 12,634,000 | 8,441,100 | 3,974,800 |
| Increase in accounts payable and accrued expenses | 22,453,500 | 10,355,800 | 13,018,300 |
| Increase (decrease) in advances for future drilling contracts | 7,502,100 | (7,961,500) | 13,175,000 |
| Increase in federal and state income taxes payable | 8,473,200 | - | - |
| Increase in funds held for future distribution | 5,434,500 | 4,500,900 | 4,493,000 |
| Total adjustments | 70,919,900 | 40,073,300 | 54,089,600 |
| Net cash provided by operating activities | 112,371,600 | 73,300,900 | 74,502,000 |
| Cash flows from investing activities: | | | |
| Capital expenditures | (106,468,500) | (45,391,800) | (73,042,300) |
| Proceeds from sale of leases to partnerships | 2,829,200 | 1,950,900 | 1,382,100 |
| Proceeds from sale of fixed assets | 9,597,600 | 94,700 | 156,800 |
| Net cash used in investing activities | (94,041,700) | (43,346,200) | (71,503,400) |
| Cash flows from financing activities: | | | |
| Proceeds from debt | 91,000,000 | 84,000,000 | 86,600,000 |
| Retirement of debt | (88,000,000) | (116,000,000) | (58,600,000) |
| Payment of debt issue costs | (423,000) | (232,500) | - |
| Proceeds from issuance of stock | 11,600 | 3,584,400 | - |
| Repurchase of treasury stock | (7,878,800) | (2,749,100) | (748,700) |
| Net cash (used in) provided from financing activities | (5,290,200) | (31,397,200) | 27,251,300 |
| Net increase (decrease) in cash and cash equivalents | 13,039,700 | (1,442,500) | 30,249,900 |
| Cash and cash equivalents, beginning of year | 77,070,400 | 78,512,900 | 48,263,000 |
| Cash and cash equivalents, end of year | $ 90,110,100 | $ 77,070,400 | $ 78,512,900 |

See accompanying Notes to Consolidated Financial Statements.

(1) Summary of Significant Accounting Policies

General

Petroleum Development Corporation (PDC or the Company) is an independent energy company engaged primarily in the drilling and development, production and marketing of natural gas and oil. Since it began oil and gas operations in 1969, the Company has grown primarily through drilling and development activities, the acquisition of producing natural gas and oil wells and the expansion of its natural gas marketing activities. As of December 31, 2005, the Company operates approximately 2,800 wells located in the Appalachian Basin, Michigan, and the Rocky Mountain Region. Substantially all of the Company's oil and gas wells are located in West Virginia, Tennessee, Pennsylvania, Michigan, North Dakota, Colorado and Kansas. The Company is involved in four business segments. The segments are drilling and development, natural gas marketing, oil and gas sales and well operations. (See Note 20)

Principles of Consolidation

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

Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

Restricted Cash

The Company is required to maintain margin deposits with brokers for outstanding derivative contracts. As of December 31, 2005 and 2004, cash in the amount of $1,500,600 and $664,900, respectively was on deposit.

Inventories

Inventories consist primarily of tubular goods and other well equipment, parts and supplies which are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased, through RNG activities, in excess of deliveries to customers and is recorded at the lower of cost or market.

Oil and Gas Properties

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

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing its reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of our financial statements, the costs are expensed to exploratory dry hole costs. If we are unable to make a final determination about the productive status of a well prior to issuance of our financial statements, the well is classified as “Suspended Well Costs” until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded. The determination of an exploratory well's ability to produce is made within one year from the completion of drilling activities. See Note 16.

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

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

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

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. The Company adopted FASB Statement No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" on January 1, 2002. The adoption of FASB No. 144 did not affect the Company's financial statements.

In accordance with FASB Statement No. 144, long-lived assets, such as property, plant, and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Maintenance and repairs are charged to expense as incurred. Major renewals and betterments are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion and amortization are removed from the accounts, the proceeds applied thereto and any resulting gain or loss is reflected in income.

Buildings

Buildings are carried at cost and depreciated on the straight-line method over estimated useful lives of 30 years.

Asset Retirement Obligations

The Company accounts for asset retirement obligations by recording the fair value of its plugging and abandonment obligations when incurred, which is at the time the well is completely drilled. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to Interest expense. The initial capitalized costs are depleted over the useful lives of the related assets, through charges to depreciation, depletion and amortization. See Note 5 for a reconciliation of asset retirement obligation activity.

Advances for Future Drilling Contracts

Advances for future drilling contracts represents funds received from Partnerships and other joint ventures for drilling activities which have not been completed and accordingly have not yet been recognized as revenue in accordance with the Company's revenue recognition policies.

Retirement Plans

The Company has a 401-K contributory retirement plan (401-K Plan) covering full-time employees. The Company provides a discretionary matching of employee contributions to the plan.

The Company has a profit sharing plan covering full-time employees. The Company's contributions to this plan are discretionary.

The Company has a deferred compensation arrangement covering executive officers of the Company as a supplemental retirement benefit.

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our sponsored drilling programs using the percentage of completion method. These contracts include the sale of equipment and the providing of services at footage rates and are completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services. Revenues are recognized under the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed continually during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts would be recorded at the time that our estimated costs exceeded the contract revenue. In the fourth quarter of 2005, the Company recorded a loss of $800,000 on uncompleted drilling contracts as cost of oil and gas well drilling operations with the related liability recorded in other accrued expenses in the accompanying consolidated balance sheet. The Company did not experience any contract losses in 2004 or 2003.

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

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

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

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

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

<u>Income Taxes</u>

Income taxes are accounted for under the asset and liability method.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

<u>Derivative Financial Instruments</u>

The Company accounts for derivative financial instruments in accordance with FAS Statement No. 133 "Accounting for Derivative Instruments and Certain Hedging Activities" as amended.

During 2005, 2004, and 2003, none of the derivative contracts qualified for hedge accounting under the terms of FAS No. 133. Accordingly, the derivative instruments are recorded as an asset or liability on the balance sheet at fair value and the change in the fair value is recorded in oil and gas price risk management, net for the Company's oil and gas commodities (derivatives related to the Company's production only), in gas sales from marketing activities for RNG's gas sales, in cost of gas marketing activities for RNG's gas purchases and in interest expense for the Company's interest rate swap (2004 and 2003 only). See Note 13.

In the accompanying balance sheet, the Company records the fair value of derivatives entered into on behalf of the affiliated partnerships and records an offsetting receivable or payable with the partnerships. See Note 9.

Stock Compensation

The Company applies the intrinsic-value based method of accounting prescribed by Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees”, and related interpretations including FASB Interpretation No. 44, “Accounting for Certain Transactions involving Stock Compensation, an interpretation of APB Opinion No. 25”, to account for its fixed-plan stock options. Under this method, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. FASB Statement No. 123, “Accounting for Stock-Based Compensation” and FASB Statement No. 148, “Accounting for Stock Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123”, established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. As permitted by existing accounting standards, the Company has elected to continue to apply the intrinsic-value-based method of accounting described above, and has adopted only the disclosure requirements of Statement 123, as amended. If the fair-value-based method had been applied to all outstanding and awards in each period, the impact in 2005 and 2004 would have been an additional expense of $94,700 and $18,400, respectively. There would have been no impact on reported net income in 2003.

| | Year Ended December 31, | |
|---|---|---|
| | 2005 | 2004 |
| Net income, as reported | $ 41,451,700 | $ 33,227,600 |
| Stock-based employee compensation expenses included in reported net income, net of related tax effects | 413,900 | 2,400 |
| Deduct total stock-based employee compensation expense determined under fair-value based method for all awards, net of tax | (508,600) | (20,800) |
| Pro forma net income | $ 41,357,000 | $ 33,209,200 |
| Basic earnings per share as reported | $2.53 | $2.05 |
| Pro forma basic earnings per share | $2.53 | $2.05 |
| Diluted earnings per share as reported | $2.52 | $2.00 |
| Pro forma diluted earnings per share | $2.52 | $2.00 |

Compensation expense for stock options is measured as the excess, if any, of the quoted market price of the Company stock at the date of the grant over the amount an optionee must pay to acquire the stock. The Company records compensation expense for restricted stock awards based on the quoted market price of the Company's stock at the date of grant and recognizes the cost over the vesting period.

The pro forma amounts that would have been reported if FAS No. 123 had been in effect for all years are based on the fair value of the stock-based awards granted for each year and recognized over the vesting period.

The fair value at date of grant for a common stock option granted under Company's option plan during 2004 was $16.75. There were no common stock options granted during 2005 or 2003. The fair value of each option granted during 2004 was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions.

| | |
|---|---|
| Dividend yield | 0% |
| Expected volatility | 39.71% |
| Risk-free interest rate | 4.06% |
| Expected option life (in years) | 7.0 |

As of December 31, 2005, there was approximately $131,700 of unrecognized, pre-tax compensation cost related to non-vested stock options. This cost is expected to be recognized over three years. The Company will adopt the provisions of FASB Statement No. 123R (revised 2004), “Accounting for Share Based Payments,” effective January 1, 2006 regarding stock compensation as discussed above. Upon adoption of FASB Statement No. 123R, the fair value of share based awards will be recognized directly in our consolidated statements of income.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with generally accepted accounting principles. Actual results could differ from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and debt obligations are estimated to be substantially the same as the fair values as of December 31, 2005, 2004 and 2003.

Reclassifications

Certain reclassifications of prior year financial statement amounts have been made to conform to current year presentations. The fair value of derivatives of $3,266,100 and $6,716,400 were broken out from other current assets and other accrued expenses, respectively as of December 31, 2004 in the accompanying consolidated balance sheets. The decrease in restricted cash for the years ended 2004 and 2003 was reclassified from cash flows from investing activities to cash flows from operating activities and the proceeds from the retirement of debt are shown gross instead of net for the years ended 2004 and 2003 in the accompanying consolidated statements of cash flows. There are certain reclassifications in the tax rate reconciliation for 2004 and the 2003 deferred tax asset related to asset retirement obligations and the deferred tax liability related to properties and equipment were both grossed-up by approximately $1.4 million. See footnote 4. The oil and gas capitalized costs as of December 31, 2004 were reclassified from intangible well equipment, intangible drilling costs, undeveloped properties and capitalized asset retirement costs to proved oil and gas properties and unproved oil and gas properties to comply with required disclosures per FASB Statement No. 69. See footnote 16. Expenditures for segment long-lived assets of $4,583,000 and $6,168,000 in 2004 and 2003, respectively were reclassified from the drilling and development segment to the oil and gas sales segment. See footnote 20.

Recently Adopted Accounting Standards

The FASB issued FIN 46R, "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 46R requires the consolidation of entities which are determined to be VIEs where 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 return, or both). The amended interpretation was effective for the first interim 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 the partnerships are not VIEs.

In June 2005, the EITF reached a consensus on EITF Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights". This consensus applies to voting right entities not within the scope of FASB Interpretation No. 46R, “Consolidation of Variable Interest Entities”, in which the investor is the general partner in a limited partnership or functional equivalent. The EITF consensus is that the general partner in a limited partnership is presumed to control that limited partnership regardless of the extent of the general partner’s ownership interest and, therefore, should include the limited partnership in its consolidated financial statements unless the limited partners have substantive participating or kick-out rights. The EITF provided that the presumption may be overcome if the limited partners possess certain substantive kick-out rights or participation rights. Pursuant to the partnership agreements which govern the limited partnerships sponsored by the Company, the presumption of control by the Company, the general partner, is overcome because the investor partners have substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner through substantive kick-out rights that can be exercised by a vote of simple majority of the investor partner units not held by the general partners without having to show cause. As a result, the partnership interests of the Company continue to be proportionately consolidated as disclosed above.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1 “Accounting for Suspended Well Costs.” This staff position amends FASB Statement No. 19 “Financial Accounting and Reporting by Oil and Gas Producing Companies” and provides guidance about exploratory well costs to companies which use the successful efforts method of accounting. The Position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well’s economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management’s evaluation of capitalized exploratory well costs. In addition, the FSP requires annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. The Company adopted FAS 19-1 during the third quarter of 2005. See Note 16. The application of this FSP did not have a significant impact on the Company’s financial position or results of operations.

Recently Issued Accounting Standards

On December 16, 2004, the FASB issued SFAS No. 123(R) "Accounting for Share Based Payments" and has issued several subsequent Staff Positions clarifying this guidance. This guidance replaced previously existing requirements under SFAS No. 123 and APB No. 25. Under SFAS No. 123(R), an entity must recognize the compensation cost related to employee services received in exchange for all forms of share-based payments to employees, including employee stock options, as an expense in its income statement. The compensation cost of the award would generally be measured based on the grant-date fair value of the award. The Company will be required to adopt SFAS No. 123(R) in the first quarter of 2006. The Company intends to use the modified prospective method for adoption of SFAS No. 123(R) as permitted by the guidance.

The Company has determined that the impact of SFAS No. 123(R) and related guidance will not be material to its financial statements. In accordance with SFAS No. 123, the Company has historically disclosed the impact on the Company’s net income and earnings per share had the fair value based method been adopted. Had the Company adopted SFAS No. 123(R) in prior periods, the impact of that standard on periods presented in these Consolidated Financial Statements would have approximated the impact of SFAS No. 123 as described in the disclosure of pro forma net income and earnings per share presented earlier in Note 1.

In December 2004, the FASB issued SFAS 153, "Exchange of Nonmonetary Assets", an amendment of APB Opinion 29, "Accounting for Nonmonetary Transactions". This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under SFAS 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance criterion and fair value is determinable, the transaction must be accounted for at fair value resulting in recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. The adoption of SFAS No. 153 will not have a material impact on our results of operations or financial position.

In June 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections" – a replacement of APB Opinion No. 20 and FASB Statement No. 3, which replaces Accounting Principles Board Opinion No. 20, "Accounting Changes", and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements", and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Consequently, we will adopt the provisions of SFAS 154 for our fiscal year beginning January 1, 2006. We currently believe that adoption of the provisions of SFAS No. 154 in 2006 will not have a material impact on our consolidated financial statements.

(2) Accounts Receivable

The allowance for doubtful accounts receivable is determined based on the Company's historical write-off experience and is the Company's best estimate of the amount of probable credit losses in the Company's existing accounts receivable. Included in other assets are noncurrent accounts receivable as of December 31, 2005 and 2004, in the amounts of $382,200 and $608,500 net of an allowance for doubtful accounts of $161,400 and $244,400, respectively.

The allowance for doubtful current accounts receivable as of December 31, 2005 and 2004 was $247,600 and $164,600, respectively.

(3) Long-Term Debt

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

As of December 31, 2005 and 2004 the outstanding balance was $24,000,000 and $21,000,000, respectively. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. At December 31, 2005, the outstanding balance was subject to a prime interest rate of 7.25%. As of the filing of this Form 10-K, the Company was in compliance with all covenants in the credit agreement, except for timely filing of this December 31, 2005 Form 10-K. The Company has received bank waivers to extend the due date of the December 31, 2005 consolidated financial statements until May 31, 2006, and the due date of the March 31, 2006 consolidated financial statements until June 15, 2006.

(4) Income Taxes

The Company's provision for income taxes consisted of the following:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Current: | | | |
| Federal | $ 17,893,900 | $ 8,649,900 | $ 2,600,700 |
| State | 3,431,600 | 1,713,300 | 870,500 |
| Total current income taxes | 21,325,500 | 10,363,200 | 3,471,200 |
| Deferred: | | | |
| Federal | 2,833,800 | 8,429,700 | 7,429,800 |
| State | 516,800 | 1,457,600 | 1,032,500 |
| Total deferred income taxes | 3,350,600 | 9,887,300 | 8,462,300 |
| Total income taxes | $ 24,676,100 | $ 20,250,500 | $ 11,933,500 |

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 35%.

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Computed "expected" tax | $ 23,144,700 | $ 18,717,300 | $ 12,116,000 |
| State income tax | 2,566,500 | 2,061,100 | 1,236,900 |
| Percentage depletion | (770,900) | (648,600) | (736,000) |
| Domestic production activities deduction | (399,400) | - | - |
| Nonconventional source fuel credit | - | - | (186,600) |
| Officers life insurance | - | - | (350,000) |
| Surtax exemption | - | - | (100,000) |
| Other | 135,200 | 120,700 | (46,800) |
| | $ 24,676,100 | $ 20,250,500 | $ 11,933,500 |

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2005 and 2004 are presented below.

| | 2005 | 2004 |
|---|---|---|
| Deferred tax assets: | | |
| Allowance for doubtful accounts | $ 159,100 | $ 159,100 |
| Drilling notes | 71,200 | 57,200 |
| Deferred revenue related to cash withheld for future plugging costs | 823,800 | 725,500 |
| Deferred compensation | 903,900 | 692,100 |
| Asset retirement obligations | 3,241,600 | 3,111,300 |
| Derivatives | 1,561,600 | 306,700 |
| Other | 8,300 | 21,800 |
| Total gross deferred tax assets | 6,769,500 | 5,073,700 |
| Less valuation allowance | - | - |
| Deferred tax assets | 6,769,500 | 5,073,700 |
| Less current deferred tax assets (included in other current assets) | (1,848,300) | (337,300) |
| Net non-current deferred tax assets | 4,921,200 | 4,736,400 |
| Deferred tax liabilities: | | |
| Properties and equipment, principally due to differences in depreciation and amortization | (31,809,700) | (27,712,700) |
| Total gross deferred tax liabilities | (31,809,700) | (27,712,700) |
| Net non-current deferred tax liability | $ (26,888,500) | $ (22,976,300) |

In assessing whether a valuation allowance for the deferred tax assets should be recorded, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

Employee stock options exercised during the year 2004 resulted in an income tax benefit of $7,394,800 that is reflected in Stockholders' Equity and as a reduction of current tax payable.

(5) Asset Retirement Obligations

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

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Balance at beginning of year | $7,998,200 | $7,390,800 | $6,046,200 |
| Obligations assumed with development activities and acquisitions | 301,400 | 238,600 | 997,200 |
| Obligations discharged with disposed properties and asset retirements | (445,800) | (67,200) | (31,800) |
| Revisions to estimates | 14,200 | - | - |
| Accretion expense | 465,200 | 436,000 | 379,200 |
| Balance at end of year | $8,333,200 | $7,998,200 | $7,390,800 |

Approximately $50,000 was classified as short-term and included in other accrued expenses as of December 31, 2005 and 2004.

If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost.

Upon the adoption of FAS No. 143 effective January 1, 2003, the Company recorded a net asset of $2,382,900 and a related liability of $6,046,200 (using a 5.75% discount rate) and a cumulative effect of change in accounting principle on prior years of $2,271,300 (net of taxes of $1,392,000).

(6) Common Stock

Stock-Based Compensation Plans

As of December 31, 2005, the Company has stock-based compensation plans for certain employees and officers. These plans are described below:

The Company maintains a long-term equity compensation plan for officers and certain key employees of the Company. Under the plan, approved by the shareholders in June 2004, awards may be issued in the form of stock options, stock appreciation rights, restricted stock, or performance shares. A total of 750,000 shares of common stock have been reserved for issuance. These awards vest over periods set at the discretion of the Compensation Committee of the Company’s Board of Directors and have a maximum exercisable period of ten years. During 2005 and 2004 the Company granted 14,000 shares and 23,380 shares, respectively, with restriction periods of four years at the market price on the date of issuance as deferred compensation to certain officers of the Company. The related compensation amount is being amortized to expense over the respective vesting periods and totaled $596,700 and $3,700 for the years ended December 31, 2005 and 2004, respectively.

The Company also maintains a restricted stock plan for non-employee directors. A total of 40,000 shares of common stock have been reserved for issuance under the plan which was approved by shareholders in June 2005. The stock is subject to restrictions ending on the earliest of various retirement or termination dates, including certain provisions for change in control. On July 8, 2005, 6,895 shares were granted at a price of $29.00 per share. Compensation expense for the year ended December 31, 2005 related to these shares of restricted stock was $63,300.

Options amounting to 16,880 shares were granted during 2004 to certain officers and directors under the Company's Stock Option Plan. These options were granted with an exercise price equal to the market value of the Company's common stock as of the date of grant and vest over a four year period. The outstanding options expire in 2014.

The following table summarizes the activity of the Company's option plans:

| | Number of Shares | Average Exercise Price | Range of Exercise Prices |
|---|---|---|---|
| Outstanding January 1, 2003 | 1,160,000 | $4.48 | $1.125 - 6.25 |
| Granted | - | - | - |
| Exercised | - | - | - |
| Outstanding December 31, 2003 | 1,160,000 | 4.48 | 1.125 - 6.25 |
| Granted | 16,880 | 37.15 | 37.15 |
| Exercised | (1,100,000) | 4.48 | 1.125-6.25 |
| Outstanding December 31, 2004 | 76,880 | 11.64 | 3.875-37.15 |
| Granted | - | - | - |
| Exercised | (3,000) | 3.88 | 3.875 |
| Outstanding December 31, 2005 | 73,880 | $11.96 | $3.875-37.15 |

Options outstanding under the Company's plans as of December 31, 2005:

| Range of Exercise Price | Options Outstanding | Remaining Life | Options Exercisable | Weighted-Average Exercise Price | Grant Date | Option Expiration Date | Vesting Period |
|---|---|---|---|---|---|---|---|
| $3.875 - $6.25 | 57,000 | 2.9 years | 57,000 | $4.50 | 1999 | 2009 | Less than 1 year |
| $37.15 | 16,880 | 9 years | 4,218 | $37.15 | 2004 | 2014 | 1 to 4 years |
| Total | 73,880 | | 61,218 | | | | |

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, management had discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. From inception of the program until December 31, 2004, the Company has repurchased 109,200 shares at an average price of $6.86 for a total purchase price of approximately $749,100. This program expired on December 31, 2004.

In March 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 2004. The Company also repurchased 1,703 shares from an employee upon retirement from the Company in June, 2004 and the treasury stock was subsequently cancelled.

On March 18, 2005, the Company publicly announced the authorization by its Board of Directors to repurchase up to 2% of the Company's outstanding common stock (331,796 shares) at fair market value at the date of purchase. At a meeting held June 10, 2005, the Board of Directors of Petroleum Development Corporation approved an amendment of the size of the stock repurchase from 2% to 10% (1,658,980 shares) of the Company's then outstanding common stock. 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 expired on December 31, 2005. The following activity has occurred since inception of the plan on March 18, 2005 until December 31, 2005.

| | |
|---|---|
| Month of Purchase | May, 2005 |
| Average Price Paid per Share | $23.75 |
| Broker/Dealer | McDonald Investments |

| | |
|---|---|
| Number of Shares Purchased | 331,796 |
| Remaining Number of Shares to Purchase | 1,327,184 |

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

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

Stock Repurchase Agreement

The Company had stock repurchase agreements with four executive officers of the Company. These agreements were eliminated in December, 2005. The agreements required the Company to maintain life insurance on each executive in the amount of $1,000,000. The agreements required the Company to utilize the proceeds from the insurance to purchase from the executives' estates or heirs, at their option, shares of the Company's stock in the event of the executive's death. The purchase price for the outstanding common stock was to be based upon the average closing asked price for the Company's stock as quoted by NASDAQ on the date of purchase. The Company is not required to purchase any shares in excess of the amount provided for by such insurance. During the fourth quarter of 2003, the Company received $1,000,000 in life insurance proceeds which was recorded as other income from the death of the Company's Chief Financial Officer who had a stock repurchase agreement. In May 2004, the Company repurchased 50,487 shares of common stock from the estate of the Company's former officer in accordance with the terms of this 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 the life insurance proceeds.

(7) Employee Benefit Plans

The Company sponsors a qualified deferred compensation plan (401-K) that enables eligible employees to contribute a portion of their compensation through payroll deductions in accordance with specific guidelines. The Company matches a percentage of the employees' contributions up to certain limits. Expenses related to this plan amounted to $450,700, $382,700 and $305,500 for 2005, 2004 and 2003, respectively.

The Company has a profit sharing plan covering full-time employees. The Company contributed $420,000, $300,000, and $250,000 to the plan in cash during 2005, 2004 and 2003, respectively.

During 2003 the Company expensed $90,000 under a deferred compensation arrangement with certain executive officers of the Company. This amount was paid to the executive officers during 2003.

The Company has a deferred compensation arrangement covering certain executive officers of the Company as a supplemental retirement benefit. During 2005, 2004 and 2003 the Company expensed $169,000, $171,900 and $181,900, respectively, and has recorded a related liability in the amount $1,129,200 and $1,000,200 as of December 31, 2005 and 2004, respectively. The Company began paying the retirement benefit during 2004 to the estate of one of the Company's former officers. The Company paid $40,000 for each of the years 2005 and 2004.

The Company maintains a non-qualified deferred compensation plan created for non-employee directors of the Company. The amount of compensation deferred by each Participant is based on Participant elections.

(8) Earnings Per Share

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Basic earnings per common share: | | | |
| Net income before cumulative effect of change in accounting principle | $41,451,700 | $33,227,600 | $22,683,700 |
| Cumulative effect of accounting change, net of tax | - | - | (2,271,300) |
| Net income | $41,451,700 | $33,227,600 | $20,412,400 |
| Weighted average common shares outstanding | 16,361,530 | 16,239,454 | 15,659,591 |
| Basic earnings per common share | $2.53 | $2.05 | $1.30 |
| Diluted earnings per common and common equivalent share: | | | |
| Net income before cumulative effect of change in accounting principle | $41,451,700 | $33,227,600 | $22,683,700 |
| Cumulative effect of accounting change, net of tax | - | - | (2,271,300) |
| Net income applicable to common stock | $41,451,700 | $33,227,600 | $20,412,400 |
| Weighted average common shares outstanding | 16,361,530 | 16,239,454 | 15,659,591 |
| Potentially dilutive securities: Stock options and awards | 65,619 | 367,177 | 638,202 |
| Weighted average common and common equivalent shares outstanding | 16,427,149 | 16,606,631 | 16,297,793 |
| Diluted earnings per common share | $2.52 | $2.00 | $1.25 |

(9) Transactions with Affiliates

Funds held for future distribution on the consolidated balance sheets of $18,346,300 and $12,911,800 primarily represents amounts owed to affiliated partnerships as of December 31, 2005 and 2004, respectively.

The Company provided oil and gas well drilling services and well operations and pipeline services to affiliated partnerships. Substantially all of the Company's revenue and expenses related to oil and gas well drilling operations and revenues from well operations and pipeline income are associated with services provided to the investing partners. Amounts due from the affiliated partnerships as of December 31, 2005 and 2004 were $7,233,800 and $2,230,600, respectively and are principally amounts due from the Partnerships related to derivative positions.

Management fees collected from the affiliated partnerships amounted to $1.7 million, $1.5 million and $2.0 million for the years ended December 31, 2005, 2004 and 2003, respectively, and are included in other income on the accompanying consolidated statements of income.

Revenues from oil and gas well drilling operations and costs of oil and gas well drilling operations each include $218,700, $102,500 and $55,800 during 2005, 2004 and 2003, respectively related to investments made by officers of the Company in working interests in wells drilled during the respective years.

The Company through its wholly-owned subsidiary, PDC Securities Incorporated, acts as Dealer-Manager of the Drilling Partnerships. PDC Securities Incorporated receives the applicable commissions and marketing allowances from the Escrow Agent of the Drilling Program and distributes them to the Soliciting Broker/Dealers who sell the programs. The commissions and marketing allowances received by PDC Securities are included in other income net of the commissions distributed to the soliciting broker/dealer. The net commissions and marketing allowance amounts included in other income were less than $1,000 for each of the years ending December 31, 2005, 2004 and 2003, respectively. The commissions and marketing allowances received by PDC Securities and distributed to the Soliciting Broker/Dealers amounted to $11,353,400, $9,747,500 and $7,994,300 for the years ended December 31, 2005, 2004, and 2003, respectively.

During 2005, 2004, and 2003, the Company paid $25,900, $22,500, and $30,000, respectively, to the Corporate Secretary's law firm for various legal services.

(10) 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, gas marketers and industrial customers. No customer accounted for 10% or more of the Company's total revenues in 2005 or 2004. One customer accounted for 11.1% of total revenues in 2003.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's derivative instruments or the counterparties to the Company's gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2005, 2004 or 2003.

Substantially all of the Company's drilling programs contain a repurchase provision where Investing Partners may request that the Company purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to the Company's financial ability to do so. The maximum annual repurchase obligation as of December 31, 2005 was approximately $9.2 million. The Company has adequate liquidity to meet this obligation. During 2005 and 2004, the Company paid $352,000 and $408,300, respectively, under this provision for the repurchase of partnership units. As of December 31, 2005, outstanding repurchase offers to investing partners totaled $256,400. In 2006, $70,700 of such outstanding offers were consummated prior to their expiration.

The Company's drilling programs formed since 1996 contain a performance supplement that requires the Company to remit a payment equal to one-half of its share of revenue from the partnership to the investing partners if certain levels of performance are not met. During 2005, 2004, and 2003 the Company paid partnerships a total of $689,700, $597,300 and $385,400, respectively in accordance with the provision. As of December 31, 2005 based upon current oil and gas reserve reports of the Partnerships with this provision, the maximum amount of this contingency is $4.8 million.

As Managing General Partner of 75 partnerships the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes the casualty insurance coverage carried by the Company and its subcontractors is adequate to meet this potential liability.

In order to secure the services for drilling rigs, the Company made commitments to the drilling contractors which call for a minimum commitment of $24,000 daily for a specified amount of time if the Company ceases to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $55,400 daily for a specified amount of time for daily use of the drilling rigs. As of December 31, 2005, commitments for these three separate contracts expire in May of 2008, July of 2009, and May of 2010. As of December 31, 2005, the Company has an outstanding minimum commitment for $22,524,000, and an outstanding maximum commitment for $59,627,000.

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

(11) Lease Obligations

The Company has entered into operating leases on behalf of itself and its Partnerships principally for the leasing of natural gas compressors on its Michigan operating facilities and office printing and copying equipment. The future minimum lease payments under these non-cancelable operating leases as of December 31, 2005 are as follows:

| Year | Lease Amount |
|---|---|
| 2006 | $356,300 |
| 2007 | 297,500 |
| 2008 | 291,600 |
| 2009 | 291,000 |
| 2010 | 167,800 |
| Thereafter | 28,000 |
| | $1,432,200 |

The Company's share of this lease expense for operating leases for the years ended December 31, 2005, 2004 and 2003 was $313,000, $310,000 and $574,700, respectively.

(12) Supplemental Disclosure of Cash Flows

The Company paid $101,300, $1,049,200 and $1,274,003 for interest in 2005, 2004 and 2003, respectively. The Company paid income taxes in 2005, 2004 and 2003 in the amounts of $10,675,000, $5,027,800 and $3,649,600, respectively.

During 2004, 337,360 options were exercised by employees exchanging 62,999 mature shares of stock with a fair value of $1,408,300. All these mature shares were subsequently cancelled.

(13) Derivative Financial Instruments

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

The fair value of the commodity based derivatives was $(9,365,700) and $(2,202,300) at December 31, 2005 and 2004, respectively. The Company recognized in the statement of income an unrealized gain (loss) on commodity based derivatives of $(3,225,900), $(1,127,900) and $632,600 for the years ended December 31, 2005, 2004, and 2003, respectively.

The following tables summarize the open derivative option and purchase and sales contracts for Riley Natural Gas and the Company as of December 31, 2005 and 2004.

Riley Natural Gas
Open Derivative Positions

| Commodity | Type | Quantity Gas-Mmbtu | Weighted Average Price | Total Contract Amount | Fair Value |
|---|---|---|---|---|---|
| Total Positions as of December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Futures/Swaps Purchases | 1,025,500 | $ 9.05 | $9,283,010 | $ 1,983,352 |
| Natural Gas | Cash Settled Futures/Swaps Sales | 3,149,000 | $ 7.95 | $25,018,610 | $ (8,688,840) |
| Natural Gas | Cash Settled Basis Swap Purchases | 450,000 | $ 0.91 | $409,500 | $ (157,663) |
| Natural Gas | Cash Settled Basis Swap Sales | 240,000 | $ 0.50 | $120,000 | $ 3,700 |
| Natural Gas | Physical Purchases | 2,819,000 | $ 8.32 | $23,456,726 | $ 7,858,489 |
| Natural Gas | Physical Sales | 585,222 | $ 10.72 | $6,272,822 | $ (670,419) |
| Natural Gas | Physical Basis Purchases | 240,000 | $ 0.45 | $108,000 | $ 8,300 |
| Natural Gas | Physical Basis Sales | 450,000 | $ 0.94 | $420,750 | $ 168,913 |
| Positions maturing in 12 months following December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Futures/Swaps Purchases | 1,025,500 | $ 9.05 | $9,283,010 | $ 1,983,352 |
| Natural Gas | Cash Settled Futures/Swaps Sales | 2,709,000 | $ 8.12 | $21,991,390 | $ (7,185,253) |
| Natural Gas | Cash Settled Basis Swap Purchases | 450,000 | $ 0.91 | $409,500 | $ (157,663) |
| Natural Gas | Cash Settled Basis Swap Sales | 220,000 | $ 0.50 | $110,000 | $ 4,900 |
| Natural Gas | Physical Purchases | 2,379,000 | $ 8.71 | $20,717,126 | $ 5,966,998 |
| Natural Gas | Physical Sales | 585,222 | $ 10.72 | $6,272,822 | $ (670,419) |
| Natural Gas | Physical Basis Purchases | 220,000 | $ 0.45 | $99,000 | $ 6,100 |
| Natural Gas | Physical Basis Sales | 450,000 | $ 0.94 | $420,750 | $ 168,913 |
| Prior Year Total Positions as of December 31, 2004 | | | | | |
| Natural Gas | Cash Settled Sale | 3,260,000 | $ 5.60 | $18,249,250 | $ (1,982,964) |
| Natural Gas | Cash Settled Purchase | 1,130,000 | $ 6.77 | $7,644,540 | $ (486,490) |
| Natural Gas | Cash Settled Sale Option | 530,000 | $ 5.30 | - | $ 134,242 |
| Natural Gas | Cash Settled Purchase Option | 265,000 | $ 7.00 | - | $ (85,541) |
| Natural Gas | Physical Contract Sale | 1,136,230 | $ 6.96 | $7,908,865 | $ 1,268,721 |
| Natural Gas | Physical Contract Purchase | 3,223,000 | $ 5.82 | $18,747,564 | $ 1,882,984 |

The maximum term for the derivative contracts listed above is 34 months.

Petroleum Development Corporation
Open Derivative Positions

| Commodity | Type | Quantity Gas-Mmbtu Oil-Barrels | Weighted Average Price | Total Contract Amount | Fair Value |
|---|---|---|---|---|---|
| Total Positions as of December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Option Sales | 5,665,000 | $8.17 | $46,273,550 | $ (12,531,796) |
| Natural Gas | Cash Settled Option Purchases | 14,030,000 | $6.36 | $89,210,000 | $ 2,660,289 |
| Positions maturing in 12 months following December 31, 2005 | | | | | |
| Natural Gas | Cash Settled Option Sales | 4,930,000 | $8.07 | $39,802,550 | $ (10,411,106) |
| Natural Gas | Cash Settled Option Purchases | 12,560,000 | $6.38 | $80,165,000 | $ 2,251,533 |
| Prior Year Total Positions as of December 31, 2004 | | | | | |
| Natural Gas | Purchase | 120,000 | $6.63 | $796,150 | $ (45,680) |
| Natural Gas | Sale Option | 7,400,000 | $4.46 | - | $ 917,553 |
| Natural Gas | Purchase Option | 3,475,000 | $5.42 | - | $ (3,138,210) |
| Crude Oil | Sale Option | 360,000 | $32.30 | - | $ 306,702 |
| Crude Oil | Purchase Option | 180,000 | $40.00 | - | $ (973,638) |

The maximum term for the derivative contracts listed above is 15 months.

In addition to including the gross assets and liabilities related to the Company's share of oil and gas production, the above tables and the accompanying consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner. The accompanying consolidated balance sheets include the negative fair value of derivatives and a corresponding receivable from the Partnerships of $5,351,500 as of December 31, 2005 and $1,418,000 as of December 31, 2004. In addition to the short-term fair value of derivatives shown in the accompanying consolidated balance sheet there are long-term assets and long-term liabilities which total to a net long-term liability of approximately $1,323,100 as of December 31, 2005 and which total to a net long-term asset of approximately $1,248,000 as December 31, 2004, respectively related to the fair value of derivatives included in accompanying balance sheet.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2005 and 2004, cash in the amount of $1,500,600 and $664,900 was on deposit.

An interest rate swap agreement was used to reduce the potential impact of increases in interest rates on variable rate long-term debt. The swap agreement expired in October 2004. The agreement required the Company, on a quarterly basis, to make a fixed-rate interest payment of 6.89% plus its current LIBOR rate margin (+1.50% At December 31, 2003) on a $10,000,000 amount related to its outstanding line of credit.

The fair value of the interest rate swap agreement was a liability of $592,700 at December 31, 2003. Current market pricing models were used to estimate fair value. The change in the fair value of the swap is included in interest expense; the related gain was $592,700 and $477,600 for the years ended December 31, 2004 and, 2003, respectively.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults during the years ended December 31, 2005, 2004 and 2003.

Changes in the fair value of commodity based derivatives are recorded in earnings because they do not qualify for hedge accounting. These changes are included in the following income statement captions:

| Income Statement Caption | |
|---|---|
| Oil and gas price risk management loss (gain), net | Includes realized and unrealized gains and losses on commodity based derivatives related to the Company's oil and gas sales. |
| Gas sales from marketing activities<br>Cost of gas marketing activities | Includes realized and unrealized gains and losses on commodity based derivatives related to the RNG gas sales and purchases. |

(14) Purchases and Sales of Oil and Gas Properties

During the first quarter of 2005, the Company sold a portion of one of its undeveloped Garfield County, Colorado leases to an unaffiliated entity. The proceeds of the sale were $6.2 million and the Company's carrying value of the property was zero. The Company was required to remit $1.0 million to the original lessor, unless it commenced construction of certain facilities adjacent to this undeveloped property subject to certain timing conditions. The gain of $5.2 million was recognized during the first quarter of 2005 and is included in "Other Income" in the accompanying consolidated statements of income. During the second quarter of 2005, the Company commenced construction of the facilities and recorded income of $1.0 million which is included in "Other income" in the accompanying consolidated statements of income.

During the second quarter of 2005, the Company completed the sale to an unaffiliated entity of 111 Pennsylvania wells it purchased from Pemco Gas, Inc. in 1998. The Company received proceeds of $3.4 million and recorded a gain of approximately $1.7 million which is included in "Other income" in the accompanying consolidated statements of income.

During the second quarter of 2003, the Company purchased 166 wells in the Denver Julesburg Basin in northeastern Colorado from Williams Production RMT Company for $28 million. The Company estimates the acquisition included approximately 22.6 billion cubic feet (Bcf) of proved developed producing (PDP) and 3.4 Bcf of proved developed non-producing reserves (PDNP), all of which is natural gas. The Company received approval for increased density well spacing in 2004. The Company drilled 20 new Niobrara wells on the property in 2004 and 72 wells in 2005.

During the fourth quarter of 2003, the Company purchased from one of its unaffiliated joint venture partners in the Denver-Julesburg Basin in Weld County, Colorado approximately 3.1 billion cubic feet equivalent (Bcfe) of proved developed producing reserves from interests in 20.6 net wells (230 gross) and 1.8 Bcfe of proved developed non-producing reserves from interests in 17 net wells (183 gross). The purchase price was $5.2 million which also included over 30 additional drilling locations.

During the fourth quarter of 2003, the Company purchased from an unaffiliated party 97 gross wells (73 net) in the Denver-Julesburg Basin located in northeast Colorado and northwestern Kansas for $6.0 million. This purchase added approximately 4.5 billion cubic feet equivalent (Bcfe) of proved developed producing and proved developed non-producing reserves to the Company's oil and gas reserves along with 100,000 acres of oil and gas leases.

(15) Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (unaudited)

Costs incurred by the Company in oil and gas property acquisition, exploration and development are presented below:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Acquisition of properties: | | | |
| Unproved properties | $16,910,200 | $ 4,583,000 | $ 6,167,800 |
| Proved properties | 1,608,300 | 720,000 | 33,946,600 |
| Development costs | 68,605,000 | 32,700,500 | 30,630,100 |
| Exploration costs | 12,942,700 | 4,169,900 | - |
| | $100,066,200 | $42,173,400 | $70,744,500 |

The proved reserves attributable to the development costs in the above table were 85,624,000 Mcf and 1,576,000 Bbls for 2005, 40,716,000 Mcf and 358,000 Bbls for 2004, 27,719,000 Mcf and 517,000 Bbls for 2003 (amounts unaudited). Of the above development costs incurred for the years ended December 31, 2005, 2004, and 2003 the amounts of $6,935,400, $1,819,619, and $4,289,600, respectively, were incurred to develop proved undeveloped properties from the prior year end.

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, recompletions and to provide facilities to extract, treat, gather and store oil and gas.

(16) Oil and Gas Capitalized Costs (unaudited)

Aggregate capitalized costs for the Company related to oil and gas exploration and production activities with applicable accumulated depreciation, depletion and amortization are presented below:

| | December 31, 2005 | December 31, 2004 |
|---|---|---|
| Proved oil and gas properties | $ 345,533,300 | $ 274,631,900 |
| Unproved oil and gas properties | 19,846,300 | 8,205,300 |
| | 365,379,600 | 282,837,200 |
| Less accumulated depreciation, depletion and amortization | 102,513,400 | 84,576,100 |
| | $ 262,866,200 | $ 198,261,100 |

Suspended Well Costs

The following table lists the capitalized exploratory well costs which are pending the determination of proved reserves.

| | |
|---|---|
| Balance, January 1, 2003 | $ - |
| Additions | - |
| Charged to expense | - |
| Balance, January 1, 2003 | - |
| Addition - Fox Federal #1-13 | 4,169,900 |
| Charged to expense | - |
| Balance, December 31, 2004 | 4,169,900 |
| Addition - Violet Olsen 34-2914 | 1,401,500 |
| Addition - Norgaard #1 | 516,900 |
| Addition - Fedora | 4,523,400 |
| Reclassification to wells, facilities and equipment based on determination of proved reserves | (4,523,400) |
| Charged to expense - Fox Federal #1-13 | (4,169,900) |
| Balance, December 31, 2005 | $1,918,400 |

Both of the above referenced wells with costs as of December 31, 2005 were drilled in the fourth quarter of 2005. The wells were completed and evaluated in 2006 and were deemed to have proved reserves.

None of the wells listed in the table have been capitalized for more than one year waiting for a proved reserve determination.

Exploratory dry hole costs of $11.1 million in the accompanying consolidated statements of income include the $4.2 million above related to costs incurred in 2004 on the Fox Federal #1-13 well plus $6.9 million of costs incurred and expensed during 2005. The 2005 costs incurred and expensed included an additional $1.2 million related to the Fox Federal #1-13 well, approximately $5.42 million related to the Coffeepot Springs #24-34 well in Colorado and four Kansas wells which totaled $314,200.

(17) Results of Operations for Oil and Gas Producing Activities (unaudited)

The results of operations for oil and gas producing activities (excluding marketing) are presented below:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| | | (Restated) | (Restated) |
| Revenue: | | | |
| Oil and gas sales | $102,559,200 | $69,492,100 | $48,393,800 |
| Expenses: | | | |
| Production costs | 16,193,400 | 14,201,300 | 9,714,600 |
| Oil and gas price risk management loss, net | 9,368,100 | 3,084,600 | 812,400 |
| Depreciation, depletion and amortization | 19,322,200 | 16,680,200 | 14,157,000 |
| Exploratory dry hole costs | 11,115,100 | - | - |
| | 55,998,800 | 33,966,100 | 24,684,000 |
| Results of operations for oil and gas producing activities before provision for income taxes | 46,560,400 | 35,526,000 | 23,709,800 |
| Provision for income taxes | 18,112,000 | 13,819,600 | 9,223,100 |
| Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs) | $28,448,400 | $21,706,400 | $14,486,700 |

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including costs such as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and production taxes. In addition, production costs include administrative expenses and depreciation applicable to support equipment associated with these activities. Depreciation, depletion and amortization expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment. The provision for income taxes is computed using statutory tax rates.

## (18) Net Proved Oil and Gas Reserves (Unaudited)

The proved reserves of oil and gas of the Company have been estimated by independent petroleum engineers at December 31, 2005, 2004 and 2003. These reserves have been prepared in compliance with the Securities and Exchange Commission and Financial Accounting Standards Board rules which require that reserve reports be prepared under economic and operating conditions existing at the Company's year-end with no provision for price and cost escalation except by contractual arrangements. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

| | Oil (Bbls) | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Proved developed and undeveloped reserves: | | | |
| Beginning of year | 3,316,000 | 3,029,000 | 2,073,000 |
| Revisions of previous estimates | 80,000 | 305,000 | 533,000 |
| Beginning of year as revised | 3,396,000 | 3,334,000 | 2,606,000 |
| New discoveries and extensions: | | | |
| Rocky Mountain Region | 1,576,000 | 358,000 | 517,000 |
| Sales of reserves to partnerships | - | (12,000) | (112,000) |
| Purchase of reserves: | | | |
| Rocky Mountain Region | 5,000 | 17,000 | 307,000 |
| Production | (439,000) | (381,000) | (289,000) |
| End of year | 4,538,000 | 3,316,000 | 3,029,000 |
| Proved developed reserves: | | | |
| Beginning of year | 3,190,000 | 2,889,000 | 1,849,000 |
| End of year | 3,860,000 | 3,190,000 | 2,889,000 |

| | Gas (Mcf) | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Proved developed and undeveloped reserves: | | | |
| Beginning of year | 197,549,000 | 180,998,000 | 128,851,000 |
| Revisions of previous estimates | (15,850,000) | (10,635,000) | 4,394,000 |
| Beginning of year as revised | 181,699,000 | 170,363,000 | 133,245,000 |
| New discoveries and extensions: | | | |
| Rocky Mountain Region | 85,624,000 | 40,716,000 | 27,719,000 |
| Dispositions to partnerships | (9,556,000) | (4,240,000) | (4,410,000) |
| Purchases of reserves: | | | |
| Michigan Basin | 47,000 | 96,000 | 265,000 |
| Rocky Mountain Region | 71,000 | 242,000 | 32,169,000 |
| Appalachian Basin | 434,000 | 744,000 | 722,000 |
| Production | (11,031,000) | (10,372,000) | (8,712,000) |
| End of year | 247,288,000 | 197,549,000 | 180,998,000 |
| Proved developed reserves: | | | |
| Beginning of year | 146,152,000 | 134,936,000 | 94,847,000 |
| End of year | 155,354,000 | 146,152,000 | 134,936,000 |

(19) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves (Unaudited)

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

| | 2005 | 2004 | | 2003 | |
|---|---|---|---|---|---|
| Future Estimated Cash Flows | $ 2,381,238,000 | $ 1,298,394,000 | | $ 1,088,415,000 | |
| Future Estimated Production Costs | (545,683,000) | (319,065,000) | | (250,735,000) | |
| Future Estimated Development Costs | (207,164,000) | (95,498,000) | | (65,275,000) | |
| Future Estimated Income Tax Expense | (633,444,000) | (343,810,000) | (1) | (300,466,000) | (1) |
| Future Net Cash Flows | 994,947,000 | 540,021,000 | (1) | 471,939,000 | (1) |
| 10% Annual Discount for Estimated Timing of Cash Flows | (589,517,000) | (310,593,000) | (1) | (269,556,000) | (1) |
| Standardized Measure of Discounted Future Estimated Net Cash Flows | $ 405,430,000 | $ 229,428,000 | (1) | $ 202,383,000 | (1) |

(1) Amounts restated since the filing of the December 31, 2004 Form 10-K/A.

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

| | 2005 | 2004 (Restated) | 2003 (Restated) |
|---|---|---|---|
| Sales of oil and gas production net of production costs | $ (86,366,000) | $ (55,291,000) | $ (38,679,000) |
| Net changes in prices and production costs | 208,353,000 | 26,768,000 | 73,241,000 |
| Extensions, discoveries, and improved recovery, less related costs | 150,654,000 | 51,413,000 | 51,583,000 |
| Sales of reserves | (14,456,000) | (7,565,000) | (5,637,000) |
| Purchase of reserves | 1,266,000 | 1,953,000 | 68,104,000 |
| Development costs incurred during the period | 24,035,000 | 8,495,000 | 10,400,000 |
| Revisions of previous quantity estimates | (24,130,000) | 6,312,000 | 13,906,000 |
| Changes in estimated income taxes | (112,054,000) | (16,160,000) | (73,907,000) |
| Accretion of discount | 38,241,000 | 33,500,000 | 15,182,000 |
| Timing and other | (9,541,000) | 22,380,000 | 2,363,000 |
| Total | $ 176,002,000 | $ 27,045,000 | $ 116,556,000 |

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

The estimated present value of future cash flows relating to proved reserves is extremely sensitive to prices used at any measurement period. The average prices used for each commodity for the years ended December 31, 2005, 2004 and 2003 were as follows:

| | Average Price | |
|---|---|---|
| As of December 31: | Oil | Gas |
| 2005 | $58.25 | $8.56 |
| 2004 | $41.63 | $5.87 |
| 2003 | $31.80 | $5.48 |

(20) Business Segments (Thousands)

The Company's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 2,800 wells from which it derives oil and gas working interests. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the years ended December 31, 2005, 2004 and 2003 is as follows:

| | 2005 | 2004 (Restated) | 2003 (Restated) |
|---|---|---|---|
| REVENUES | | | |
| Drilling and Development | $ 99,963 | $ 94,076 | $ 57,509 |
| Natural Gas Marketing | 121,387 | 94,675 | 73,186 |
| Oil and Gas Sales | 102,559 | 69,492 | 48,394 |
| Well Operations | 8,760 | 7,677 | 6,907 |
| Unallocated amounts (1) | 10,464 | 1,833 | 3,475 |
| | $ 343,133 | $ 267,753 | $ 189,471 |
| SEGMENT INCOME | | | |
| Drilling and Development | $ 11,778 | $ 16,380 | $ 10,564 |
| Natural Gas Marketing | 1,737 | 1,784 | 815 |
| Oil and Gas Sales (3) | 46,560 | 35,526 | 23,710 |
| Well Operations | 3,539 | 3,695 | 2,618 |
| Unallocated amounts (1) | | | |
| General and Administrative | (6,960) | (4,506) | (4,974) |
| Interest expense | (682) | (674) | (1,195) |
| Other (2) | 10,156 | 1,273 | 3,079 |
| Total | $ 66,128 | $ 53,478 | $ 34,617 |
| SEGMENT ASSETS | | | |
| Drilling and Development | $ 89,030 | $ 64,348 | $ 62,546 |
| Natural Gas Marketing | 56,518 | 31,234 | 17,007 |
| Oil and Gas Sales | 256,621 | 211,255 | 194,371 |
| Well Operations | 31,407 | 16,518 | 11,602 |
| Unallocated amounts | | | |
| Cash | 3,383 | 112 | 800 |
| Other | 12,126 | 11,561 | 11,216 |
| Total | $ 449,085 | $ 335,028 | $ 297,542 |
| EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS | | | |
| Drilling and Development | $ - | $ - | $ - |
| Natural Gas Marketing | 1 | 6 | - |
| Oil and Gas Sales | 100,066 | 42,173 | 69,756 |
| Well Operations | 3,949 | 1,911 | 2,944 |
| Unallocated amounts | 2,452 | 1,302 | 342 |
| Total | $ 106,468 | $ 45,392 | $ 73,042 |

(1) Items which are not allocated in assessing segment performance.
(2) Includes interest on investments, partnership management fees and gains on sales of assets in 2005, 2004 and 2003 which are not allocated in assessing segment performance.
(3) Includes $11.1 million in exploratory dry hole costs for the year ended December 31, 2005.

(21) Quarterly Financial Data (Unaudited)

Quarterly financial data for the years ended December 31, 2005, 2004 and 2003, are as follows:

| | 2005 | | | | |
|---|---|---|---|---|---|
| | Quarter | | | | Year |
| | First (Restated) | Second (Restated) | Third (Restated) | Fourth | |
| Revenues: | | | | | |
| Oil and gas well drilling operations | $ 25,366,300 | $ 28,110,800 | $ 32,266,600 | $ 14,219,200 | $ 99,962,900 |
| Gas sales from marketing activities | 17,522,000 | 25,917,100 | 14,970,300 | 62,694,700 | 121,104,100 |
| Oil and gas sales | 18,663,700 | 21,542,800 | 28,413,400 | 33,939,300 | 102,559,200 |
| Well operations and pipeline income | 1,927,100 | 2,067,900 | 2,290,900 | 2,473,700 | 8,759,600 |
| Other income | 6,213,800 | 3,492,600 | 209,400 | 831,500 | 10,747,300 |
| Total revenues | 69,692,900 | 81,131,200 | 78,150,600 | 114,158,400 | 343,133,100 |
| Costs and expenses: | | | | | |
| Cost of oil and gas well drilling operations | 20,644,100 | 23,743,000 | 28,733,500 | 15,064,300 | 88,184,900 |
| Cost of gas marketing activities | 17,901,600 | 26,177,300 | 14,269,500 | 61,295,300 | 119,643,700 |
| Oil and gas production costs and well operations costs | 3,978,100 | 4,481,200 | 6,263,000 | 5,212,400 | 19,934,700 |
| Exploratory dry hole costs | - | 4,864,000 | 135,800 | 6,115,300 | 11,115,100 |
| General and administrative expenses | 1,617,500 | 1,266,000 | 1,645,500 | 2,431,300 | 6,960,300 |
| Depreciation, depletion and amortization | 4,856,900 | 4,845,100 | 5,120,000 | 6,294,200 | 21,116,200 |
| Total costs and expenses | 48,998,200 | 65,376,600 | 56,167,300 | 96,412,800 | 266,954,900 |
| Income from operations | 20,694,700 | 15,754,600 | 21,983,300 | 17,745,600 | 76,178,200 |
| Interest expense | 147,800 | 143,000 | 142,200 | 249,300 | 682,300 |
| Oil and gas price risk management loss (gain), net | 3,659,100 | (858,400) | 9,922,300 | (3,354,900) | 9,368,100 |
| Income before income taxes | 16,887,800 | 16,470,000 | 11,918,800 | 20,851,200 | 66,127,800 |
| Income taxes | 6,247,900 | 6,091,400 | 4,413,000 | 7,923,800 | 24,676,100 |
| Net income | $ 10,639,900 | $ 10,378,600 | $ 7,505,800 | $ 12,927,400 | $ 41,451,700 |
| Basic earnings per common share | $ 0.64 | $ 0.63 | $ 0.46 | $ 0.80 | $ 2.53 |
| Diluted earnings per common and common equivalent share | $ 0.64 | $ 0.63 | $ 0.46 | $ 0.79 | $ 2.52 |

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

| | 2004 (Restated) | | | | |
|---|---|---|---|---|---|
| | Quarter | | | | Year |
| | First | Second | Third | Fourth | |
| Revenues: | | | | | |
| Oil and gas well drilling operations | $ 22,109,100 | $ 24,065,900 | $ 24,070,300 | $ 23,830,700 | $ 94,076,000 |
| Gas sales from marketing actitities | 22,058,900 | 24,954,300 | 22,630,200 | 24,983,400 | 94,626,800 |
| Oil and gas sales | 16,316,200 | 16,209,000 | 16,580,500 | 20,386,400 | 69,492,100 |
| Well operations and pipeline income | 1,706,900 | 1,737,600 | 1,875,000 | 2,357,400 | 7,676,900 |
| Other income | 58,100 | 622,000 | 589,000 | 611,600 | 1,880,700 |
| Total revenues | 62,249,200 | 67,588,800 | 65,745,000 | 72,169,500 | 267,752,500 |
| Costs and expenses: | | | | | |
| Cost of oil and gas well drilling operations | 17,965,500 | 19,579,400 | 19,681,300 | 20,470,000 | 77,696,200 |
| Cost of gas marketing activities | 21,889,700 | 24,605,800 | 22,047,400 | 24,338,300 | 92,881,200 |
| Oil and gas production and well operations costs | 3,775,500 | 3,796,200 | 3,753,600 | 5,951,900 | 17,277,200 |
| General and administrative expenses | 994,200 | 900,900 | 926,300 | 1,684,200 | 4,505,600 |
| Depreciation, depletion and amoritization | 4,544,400 | 4,451,300 | 4,312,300 | 4,847,900 | 18,155,900 |
| Total costs and expenses | 49,169,300 | 53,333,600 | 50,720,900 | 57,292,300 | 210,516,100 |
| Income from operations | 13,079,900 | 14,255,200 | 15,024,100 | 14,877,200 | 57,236,400 |
| Interest expense | 209,600 | 194,400 | 223,100 | 46,600 | 673,700 |
| Oil and gas price risk management loss (gain), net | 830,000 | 868,700 | 2,378,800 | (992,900) | 3,084,600 |
| Income before income taxes | 12,040,300 | 13,192,100 | 12,422,200 | 15,823,500 | 53,478,100 |
| Income taxes | 4,334,400 | 4,755,400 | 4,506,400 | 6,654,300 (1) | 20,250,500 |
| Net income | $ 7,705,900 | $ 8,436,700 | $ 7,915,800 | $ 9,169,200 | $ 33,227,600 |
| Basic earnings per common share | $ 0.49 | $ 0.52 | $ 0.49 | $ 0.55 | $ 2.05 |
| Diluted earnings per common and common-equivalent share | $ 0.47 | $ 0.51 | $ 0.47 | $ 0.54 | $ 2.00 |

(1) Includes an adjustment of approximately $600,000 to the tax provision of the prior three quarters.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

| | 2003 (Restated) | | | | |
|---|---|---|---|---|---|
| | Quarter | | | | Year |
| | First | Second | Third | Fourth | |
| Revenues: | | | | | |
| Oil and gas well drilling operations | $ 17,147,000 | $ 9,507,000 | $ 11,325,800 | $ 19,529,800 | $ 57,509,600 |
| Gas sales from marketing actitities | 20,651,000 | 16,805,000 | 20,370,200 | 15,305,500 | 73,131,700 |
| Oil and gas sales | 9,658,200 | 11,213,200 | 13,304,200 | 14,218,200 | 48,393,800 |
| Well operations and pipeline income | 1,542,800 | 1,671,500 | 1,747,500 | 1,945,300 | 6,907,100 |
| Other income | 327,400 | 285,100 | 488,300 | 2,427,700 | 3,528,500 |
| Total revenues | 49,326,400 | 39,481,800 | 47,236,000 | 53,426,500 | $ 189,470,700 |
| Costs and expenses: | | | | | |
| Cost of oil and gas well drilling operations | 13,325,300 | 7,760,600 | 9,201,400 | 16,658,600 | $ 46,945,900 |
| Cost of gas marketing activities | 20,937,600 | 16,443,700 | 19,797,200 | 15,182,900 | 72,361,400 |
| Oil and gas production and well operations cost | 2,694,200 | 3,363,300 | 3,868,500 | 3,325,300 | 13,251,300 |
| General and administrative expenses | 1,177,700 | 1,186,600 | 1,377,300 | 1,232,800 | 4,974,400 |
| Depreciation, depletion and amoritization | 3,146,400 | 3,594,400 | 4,140,100 | 4,431,900 | 15,312,800 |
| Total costs and expenses | 41,281,200 | 32,348,600 | 38,384,500 | 40,831,500 | $ 152,845,800 |
| Income from operations | 8,045,200 | 7,133,200 | 8,851,500 | 12,595,000 | 36,624,900 |
| Interest expense | 215,500 | 257,300 | 355,000 | 367,500 | 1,195,300 |
| Oil and gas price risk-management loss(gain), net | 788,400 | (426,400) | (550,900) | 1,001,300 | 812,400 |
| Income before income taxes and cumulative effect of change in accounting principle | 7,041,300 | 7,302,300 | 9,047,400 | 11,226,200 | 34,617,200 |
| Income taxes | 2,324,500 | 2,410,100 | 2,986,900 | 4,212,000 | 11,933,500 |
| Net income before cumulative effect of change in accounting principle | 4,716,800 | 4,892,200 | 6,060,500 | 7,014,200 | 22,683,700 |
| Cumulative effect of change in accounting principle (net of taxes of $1,392,000) | (2,271,300) | - | - | - | (2,271,300) |
| Net income | $ 2,445,500 | $ 4,892,200 | $ 6,060,500 | $ 7,014,200 | $ 20,412,400 |
| Basic earnings per common share before accounting change | $ 0.30 | $ 0.31 | $ 0.39 | $ 0.45 | $ 1.45 |
| Cumulative effect of change in accounting principle | $ (0.15) | - | - | - | $ (0.15) |
| Basic earnings per common share | $ 0.15 | $ 0.31 | $ 0.39 | $ 0.45 | $ 1.30 |
| Diluted earnings per share before accounting change | $ 0.29 | $ 0.30 | $ 0.37 | $ 0.43 | $ 1.39 |
| Cumulative effect of change in accounting principle | $ (0.14) | - | - | - | $ (0.14) |
| Diluted earnings per common and common equivalent share | $ 0.15 | $ 0.30 | $ 0.37 | $ 0.43 | $ 1.25 |

The following tables set forth the effect of the restatement (See footnote 22 for discussion of restatement) on the affected line items within the Company's previously reported consolidated statements of income for the quarters ended March 31, 2005, June 30, 2005 and September 30, 2005 and for each of the quarters in 2004 and 2003.

| Quarterly Information (Unaudited) (in thousands) | 2005 | | | | | |
|---|---|---|---|---|---|---|
| | First Quarter | | Second Quarter | | Third Quarter | |
| Consolidated Statements of Income Data: | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated |
| Revenues: | | | | | | |
| Oil and gas well drilling operations | $ 32,351 | $ 25,366 | $ 36,057 | $ 28,111 | $ 39,711 | $ 32,267 |
| Well operations and pipeline income | $ 2,112 | $ 1,927 | $ 2,244 | $ 2,068 | $ 2,483 | $ 2,291 |
| Other income | $ 6,214 | $ 6,214 | $ 3,573 | $ 3,493 | $ 209 | $ 209 |
| Total revenues | $ 76,863 | $ 69,693 | $ 89,334 | $ 81,131 | $ 85,787 | $ 78,150 |
| Costs and expenses: | | | | | | |
| Cost of oil and gas well drilling | $ 27,629 | $ 20,644 | $ 31,689 | $ 23,743 | $ 36,178 | $ 28,734 |
| Oil and gas production and well operations costs | $ 4,163 | $ 3,978 | $ 4,738 | $ 4,482 | $ 6,455 | $ 6,263 |
| Total costs and expenses | $ 56,168 | $ 48,998 | $ 73,579 | $ 65,376 | $ 63,804 | $ 56,167 |
| Income from operations | $ 20,695 | $ 20,695 | $ 15,755 | $ 15,755 | $ 21,983 | $ 21,983 |

Quarterly Information (Unaudited)
(in thousands)

| | 2004 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | First Quarter | | Second Quarter | | Third Quarter | | Fourth Quarter | |
| Consolidated Statements of Income Data: | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated |
| Revenues: | | | | | | | | |
| Oil and gas well drilling operations | $ 29,499 | $ 22,109 | $ 29,454 | $ 24,066 | $ 30,394 | $24,070 | $29,864 | $23,831 |
| Well operations and pipeline income | $ 1,838 | $ 1,707 | $ 1,912 | $ 1,738 | $ 2,074 | $ 1,875 | $ 2,561 | $ 2,357 |
| Other income | $ 58 | $ 58 | $ 687 | $ 622 | $ 589 | $ 589 | $ 612 | $ 612 |
| Total revenues | $ 69,770 | $ 62,249 | $ 73,217 | $ 67,589 | $ 72,268 | $65,745 | $78,405 | $72,169 |
| Costs and expenses: | | | | | | | | |
| Costs of oil and gas well drilling operations | $ 25,356 | $ 17,966 | $ 24,967 | $ 19,579 | $ 26,005 | $19,681 | $26,503 | $20,470 |
| Oil and gas production and well operations costs | $ 3,906 | $ 3,776 | $ 4,036 | $ 3,796 | $ 3,952 | $ 3,754 | $ 6,156 | $ 5,952 |
| Total costs and expenses | $ 56,690 | $ 49,169 | $ 58,961 | $ 53,333 | $ 57,244 | $50,721 | $63,528 | $57,292 |
| Income from operations | $ 13,080 | $ 13,080 | $ 14,255 | $ 14,255 | $ 15,024 | $15,024 | $14,877 | $14,877 |

Quarterly Information (Unaudited)
(in thousands)

| Consolidated Statements of Income Data: | 2003 First Quarter As previously reported | First Quarter As restated | Second Quarter As previously reported | Second Quarter As restated | Third Quarter As previously reported | Third Quarter As restated | Fourth Quarter As previously reported | Fourth Quarter As restated |
|---|---|---|---|---|---|---|---|---|
| Revenues: | | | | | | | | |
| Oil and gas well drilling operations | $ 21,498 | $ 17,147 | $ 11,866 | $ 9,507 | $ 14,080 | $11,326 | $24,398 | $19,530 |
| Well operations and pipeline income | $ 1,648 | $ 1,543 | $ 1,769 | $ 1,672 | $ 1,865 | $ 1,747 | $ 2,066 | $ 1,945 |
| Other income | $ 385 | $ 327 | $ 285 | $ 285 | $ 488 | $ 488 | $ 2,428 | $ 2,428 |
| Total revenues | $ 53,840 | $ 49,326 | $ 41,938 | $ 39,482 | $ 50,108 | $47,236 | $58,415 | $53,426 |
| Costs and expenses: | | | | | | | | |
| Costs of oil and gas well drilling operations | $ 17,676 | $ 13,325 | $ 10,120 | $ 7,761 | $ 11,956 | $ 9,201 | $21,526 | $16,659 |
| Oil and gas production and well operations costs | $ 2,857 | $ 2,694 | $ 3,460 | $ 3,363 | $ 3,986 | $ 3,869 | $ 3,446 | $ 3,325 |
| Total costs and expenses | $ 45,795 | $ 41,281 | $ 34,805 | $ 32,349 | $ 41,256 | $38,384 | $45,820 | $40,831 |
| Income from operations | $ 8,045 | $ 8,045 | $ 7,133 | $ 7,133 | $ 8,852 | $ 8,852 | $12,595 | $12,595 |

(22) Restatement

In this Annual Report on Form 10-K for the year ended December 31, 2005, the Company is amending and restating its prior consolidated statements of income for the years ended December 31, 2004 and 2003, and for each of the quarters ended in the years 2004 and 2003. This Annual Report on Form 10-K is also amending and restating our consolidated statements of income for the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005.

As previously announced in a Form 8K as filed with the Securities and Exchange Commission on April 3, 2006, the Company identified that corrections were needed to certain revenues and expenses to properly reflect the elimination of transactions between the Company and the limited partnerships. The corrections resulted in elimination of revenues and expenses of equal amounts. The restatement had no effect on Net Income, Earnings per Share, Cash Flow, Proved Oil and Gas Reserves, or the Company's financial position. In addition, the Company made other corrections that in the prior periods were considered immaterial both individually and in the aggregate.

Effects of the Restatement

The restatement also impacted or made changes to the following financial statement footnotes; Note 17, 19, 20, 21 and added Note 22, Restatement.

The following tables set forth the effects of the restatement on the affected line items within the Company's previously reported Consolidated Statements of Income for the years 2004 and 2003.

| For the year ended December 31, (in thousands) Consolidated Statements of Income Data: | 2004 | | 2003 | |
|---|---|---|---|---|
| | As previously reported | As restated | As previously reported | As restated |
| Revenues: | | | | |
| Oil and gas well drilling operations | $ 119,211 | $ 94,076 | $ 71,842 | $ 57,510 |
| Well operations and pipeline income | $ 8,385 | $ 7,677 | $ 7,348 | $ 6,907 |
| Other Income | $ 1,946 | $ 1,881 | $ 3,586 | $ 3,529 |
| Total revenues | $ 293,660 | $ 267,753 | $ 204,301 | $ 189,471 |
| Costs and expenses: | | | | |
| Costs of oil and gas well drilling operations | $ 102,831 | $ 77,696 | $ 61,278 | $ 46,946 |
| Oil and gas production and well operations costs | $ 18,050 | $ 17,277 | $ 13,749 | $ 13,251 |
| Total costs and expenses | $ 236,423 | $ 210,516 | $ 167,676 | $ 152,846 |
| Income from operations | $ 57,236 | $ 57,236 | $ 36,625 | $ 36,625 |

## SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years Ended December 31, 2005, 2004 and 2003

| Column A<br>Description | Column B<br>Balance at Beginning of Period | Column C<br>Additions, Charged to Costs and Expenses | Column D<br>Deductions | Column E<br>Balance At End of Period |
|---|---|---|---|---|
| Allowance for doubtful accounts deducted from accounts receivable in the Balance sheet | | | | |
| 2005 | $409,000 | $ - | $ - | $409,000 |
| 2004 | $487,300 | $ - | $ 78,300 (a) | $409,000 |
| 2003 | $524,500 | $ - | $ 37,200 (a) | $487,300 |

(a) Deduction relates to the write-off of accounts receivable deemed uncollectible.