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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004

Commission File Number 0-7246

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transaction period from _______ to ________

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 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. [ ]

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

As of March 21, 2005, 16,589,824 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, 2004, the last business day of the Registrant's most recently completed second quarter was $318,343,540 (based on the last traded price of $27.42).

DOCUMENTS INCORPORATED BY REFERENCE

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

PART I

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, 2004, the Company operates approximately 2,700 wells located in the Appalachian basin, Michigan, and the Rocky Mountain Region, with gross proved reserves of 523 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 217 Bcfe. The Company's share of production for the fourth quarter of 2004 averaged 34,500 Mcfe per day.

Business Segments

The Company's operations are divided into four segments for management and reporting purposes. (See Consolidated Financial Statements, Note 19. Business Segments)

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 a 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% ownership interest in these drilling limited partnerships. In 2004, the Company, through four public drilling partnerships, raised $100 million making it the sponsor of the largest public oil and gas partnership program 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 hedging 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 2,700 wells ranging from a few percent to 100 percent. During 2004 approximately 14% of the Company's production was generated by Appalachian Basin wells, 14% by Michigan Basin wells and 72% by Rocky Mountain wells. As of the end of 2004, the Company's total proved reserves were located as follows: Appalachian Basin 19%, Michigan 12% and Rocky Mountain Region 69%. The majority of the Company's undeveloped reserves are in the Rocky Mountain Region and the planned drilling for 2005 will be focused in that area.

Well Operations

The Company operates almost all of the approximately 2,700 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 Appalachian Basin since its inception in 1969, in Michigan since 1997, and in the Rocky Mountain Region since 1999.

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. The Company’s management believes these deeper 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 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 158 wells in 2004, compared to 111 wells in 2003. In addition the Company seeks to maximize the value of its existing wells through a program of well recompletions and infill 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, 2004, the Company had leases or other development rights to 1,700 undeveloped acres in the Michigan Basin, 10,000 undeveloped acres in the northern Appalachian Basin and 152,830 undeveloped acres in the Rocky Mountain Region. The Company also has about 40 Wattenberg Field wells that it plans to recomplete in 2005, and the new wells it has drilled since 1999 in the field will be available for recompletions beginning in 2006.

To support future development activities the Company began an exploratory drilling program in 2004 that it plans to continue in 2005. 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 and that 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 2005, 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 2005. However 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's utilizes its marketing subsidiary, Riley Natural Gas, to manage the marketing of the Company's oil and natural gas and its commodity hedges. This allows the Company to maintain better control over third party risk in sales and hedging activities. The Company uses natural gas and oil hedges 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 2004 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; 24% and 15% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; and 25% by utilities for the generation of electricity; and 1% 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 2004. Continuing increases in world energy demand appear likely in 2005 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 use 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 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, 2004, the Company had leasehold rights to approximately 164,530 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 2004, the Company drilled a total of 157 development wells of which 153 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 an interest in each well it drills.

The Company also drilled one exploratory well in 2004 and plans additional exploratory wells in 2005. As of the date of this report the exploratory well had been completed and testing was underway but the well had not been classified as successful or dry. Testing of the well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing in the second quarter. If the well is determined to be a dry hole, its cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting. The cost of the well as of January 31, 2005 is $4,362,000. 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. 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. As 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 lock in its development costs in advance of drilling when possible.

Drilling Activity

The following table summarizes the Company's development 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. The Company's exploratory wells drilled in the past five years (not included in the table data) consist of one well (1.0 net) drilled in 2004 and one dry hole (1.0 net) drilled in 2003. The exploratory well drilled in 2004 was completed late in the year. Testing was commenced in December and suspended in January due to lease restrictions on the federal lease that restrict access for heavy equipment including service units during certain periods of the year to protect wildlife and the environment. The lease restrictions would not prevent the operation of producing wells during this period. Testing is scheduled to resume late in the second quarter. The well cannot be classified as dry or productive until testing is complete. If it is classified as dry the cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting.

	Development Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
2000	97	27.39	97	27.39	-	-
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	.60
Total	575	152.61	565	149.95	10	2.66

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 $60 million of a $100 million credit facility with J.P. Morgan Chase Bank, NA and BNP Paribas, however it has more than adequate reserves to allow the full line to be activated if necessary. As of the end of 2004 the Company had $21 million outstanding of 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 partnerships sponsored by the Company. A part of the Company's drilling investment is used to purchase an interest in 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 partnerships had $100 million in subscriptions in 2004, $78.3 million in subscriptions in 2003, and $56.9 million in subscriptions in 2002. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 22% of the aggregate subscriptions received for that particular drilling partnership and receives a 20% working interest in each partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership, during 2004 this amounted to $22.0 million.. The funds received from these programs are restricted to use in 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 assign 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. Currently the agreements can be classified as on a "footage-based" rate, whereby the Company receives drilling and completion payments based on the depth of the well. Basic drilling and completion operations are performed on a footage-based rate, with leases being contributed at the Company's cost. The Company may also purchase a working interest in the subject properties. In its financial reporting the Company reports only its share of reserves, production, revenue and costs associated with wells in which other investors participate. The level of the Company's third party 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.

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 2004, other potential purchasers outbid the Company, therefore none of its offers were successful. Several purchases made during 2003 as described below did contribute to the Company’s increased production in 2004.

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) at the time of acquisition, all of which is natural gas.

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.

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 included approximately 4.5 billion cubic feet equivalent (Bcfe) of proved developed producing and proved developed non-producing reserves along with 100,000 acres of oil and gas leases.

The Company also purchased a number of small interests in its partnerships from investor partners wishing to sell their interests in 2004, 2003 and 2002.

Production

The following table shows the Company's net production in barrels (Bbl) of crude oil and in thousand cubic feet (Mcf) of natural gas and the costs and weighted average selling prices thereof, for the last five years.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Production(1):					
Oil(MBbl)	381	289	227	195	109
Natural Gas (MMcf)	10,372	8,712	6,462	6,085	5,737
Equivalent Mmcf(2)	12,658	10,449	7,824	7,255	6,391
Average sales price:					
Oil (per Bbl)(3)	$35.13	$29.39	$24.41	$22.53	$29.99
Natural gas (per Mcf)(3)	$5.26	$4.42	$2.68	$3.53	$2.74
Average production cost (lifting cost)					
Per equivalent Mcf(4)	$1.18	$0.98	$0.82	$0.83	$0.66

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(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 derivative instruments as hedges to manage a portion of its exposure to price volatility of its natural gas and oil sales. The effect of hedges on the average sales price of natural gas per Mcf for the years ended December 31, 2004, 2003, 2002, 2001, and 2000 was $(0.09), $(0.09), $0.02, $(0.56),and $(0.91) respectively. The effect of hedges on the average sales price of oil per barrel for the year ended December 31, 2004 was $(2.71). There was no oil hedged in earlier years.

(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 Costs in Management's Discussion and Analysis.

Natural Gas Sales

Natural gas produced by the Company's well interests is sold under contracts with terms ranging from one month to three years. 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. Two customers accounted for 13.8% and 11.1% respectively of the Company's revenues from oil and gas sales (7.8% and 6.3% of total revenues) in 2004. Three customers accounted for 16.6%, 17.4% and 14.3%, respectively of the Company's revenues from oil and gas sales (9.8%, 10.3% and 8.5% of total revenues) in 2003. Two customers accounted for 21.1% and 11.0%, respectively of the Company's revenues from oil and gas sales (10.8% and

5.6% of total revenues) in 2002. No other single purchaser of the Company's natural gas accounted for 10% or more of the Company's total revenues during 2004, 2003, and 2002.

At December 31, 2004, natural gas produced by the Company sold at prices per Mcf ranging from $0.90 to $12.22, 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 2004 was $5.26 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 and Michigan, and most of the Company's wells in Wattenberg field in Colorado, produce oil in addition to natural gas. At the end of 2004 oil was about 9% 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 at prices and in accordance with arrangements that are customary in the oil industry. One purchaser accounted for 7.6%, 11.0% and 11.9% of the Company's revenues from oil and gas sales (4.3%, 6.5% and 5.6% of total revenues) in 2004, 2003, and 2002. At December 31, 2004, oil produced by the Company sold at prices ranging from $37.25 to $49.00 per barrel, depending upon the location and quality of oil. In 2004, the weighted net average price per barrel of oil sold by the Company was $35.13.

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.

Hedging Activities

The Company utilizes commodity-based derivative instruments as hedges 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 contracts hedge committed and anticipated natural gas purchases and sales and anticipated oil sales, generally forecasted to occur within the next two year period. Company policy prohibits the use of natural gas or oil futures or options for speculative purposes and permits utilization of hedges only if there is an underlying physical position.

The Company through RNG has extensive experience with the use of financial hedges to reduce the risk and impact of natural gas price changes. These hedges 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 price realized for the sale of natural gas and oil. In order for contracts to serve as effective hedges, the derivatives must be highly effective in offsetting changes in cash flows of hedged items. There must be sufficient correlation to the underlying hedged transaction. While hedging can help provide price protection if spot prices drop, hedges can also limit upside potential.

For unhedged 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 hedge transactions. In addition, the Company may also close out any portion of hedges that may exist from time to time which may result in a gain or loss on that hedge transaction. Generally the Company hedges only a portion of its anticipated production, so some or all of the production is subject to the full fluctuation of market pricing.

Well Operations

The Company currently operates approximately 1,476 wells in the Appalachian Basin, 204 wells in the Michigan Basin and 991 wells in the Rocky Mountain Region. The Company's ownership interest in these wells ranges from 0% to 100%, and, on average, the Company has an approximate 51% ownership interest in the wells it operates.

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 substantial 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. In as much 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 have 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 2004 were not significant in relation to operating costs and the Company expects no material change in 2005. 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 natural gas and obtaining desirable 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 2004 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, 2004, the Company had 120 employees, including 17 in finance and data processing, 8 in administration, 12 in exploration and development, 78 in production and 5 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's employees are not covered by a collective bargaining agreement. The Company considers relations with its employees to be excellent.

Risks Related to the Oil and Natural Gas Industry and the Company

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, successful efforts accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows. 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 Wright & Company (Wright), independent petroleum engineers, using pricing, production, cost, tax and other information provided by the Company. Over time, Wright may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. Also, Wright makes 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, 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 prices and costs in effect on the day of estimate. 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, 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 we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us 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.

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 reserves, 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.

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 wells 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 decreased profitability for the Company and the temporary or permanent loss of part or all of its partnership drilling activity.

The Company's drilling and development segment receives virtually all of its revenue from the publicly registered 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 sponsor of SEC registered 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 11% of the partnership units in 2004. 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 other reason, the sales of the partnership units would decline, reducing or eliminating the revenue and profits associated with the drilling and completion business segment.

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 net income and could have a negative impact on the Company's stock price.

The Company plans to increase its exploratory drilling in 2005 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 they 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.

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 2004 on a per unit basis, particularly in the Rocky Mountain region, and the Company believes these values may continue to increase in 2005. 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 writedown 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 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 available under our revolving credit facility is not sufficient to meet our capital requirements, the 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.

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. The revolving credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. 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.

A substantial part of the Company’s producing properties are 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, 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 it also participates in some cases through joint operating agreements under which it owns partial interests in oil and natural gas properties. 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. 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 a lack of a 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.

Our hedging 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 hedging arrangements for a portion of its oil and natural gas production from its own wells, and for gas purchases and sales by its marketing subsidiary. Hedging 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 hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. In addition, 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.

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 hedging arrangements as well as the hedging arrangements of 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.

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 of the 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, 2004.

	Productive Wells			
	Gas		Oil	
Location	Gross	Net	Gross	Net
Colorado	964	530.42	-	-
Kansas	26	18.00	-	-
Michigan	197	109.96	7	2.66
North Dakota	-	-	1	.20
Pennsylvania	530	168.71	-	-
Tennessee	1	0.71	35	13.62
West Virginia	906	516.76	4	1.72
Total	2,624	1,344.56	47	18.20

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 Wright & Company Inc., independent petroleum engineers ("Wright & Company"), to be 197,549,000 Mcf of natural gas and 3,316,000 Bbls of oil at December 31, 2004, 180,998,000 Mcf of natural gas and 3,029,000 Bbls of oil at December 31, 2003, and 128,851,000 Mcf of natural gas and 2,073,000 Bbls of oil at December 31, 2002.

The Company's approximate net proved developed reserves were estimated, by Wright & Company, to be 146,152,000 Mcf of natural gas and 3,190,000 Bbl of oil at December 31, 2004, 134,936,000 Mcf of natural gas and 2,889,000 Bbls of oil at December 31, 2003, and 94,847,000 Mcf of natural gas and 1,849,000 Bbls of oil at December 31, 2002.

The Company's oil and natural gas reserves by region are as follows as of December 31, 2004:

	Oil (Mbbl)	Gas (Mmcf)	Natural Gas Equivalent (Mmcfe)	%
Proved Developed Reserves				
Appalachian Basin	48	41,384	41,672	25.21%
Michigan Basin	52	24,895	25,207	15.25%
Rocky Mountain Region	3,090	79,873	98,413	59.54%
Total Proved Developed Reserves	3,190	146,152	165,292	100.00%
Proved Undeveloped Reserves				
Appalachian Basin	0	0	0	0.00%
Michigan Basin	0	630	630	1.21%
Rocky Mountain Region	126	50,767	51,523	98.79%
Total Proved Undeveloped	126	51,397	52,153	100.00%
Total Proved Reserves				
Appalachian Basin	48	41,384	41,672	19.16%
Michigan Basin	52	25,525	25,837	11.88%
Rocky Mountain Region	3,216	130,640	149,936	68.96%
Total Proved Reserves	3,316	197,549	217,445	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, 2004. Reserves cannot be measured exactly, as 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 Wright & Company to be $234.2 million as of December 31, 2004, $217.3 million as of December 31, 2003, and $98.5 million as of December 31, 2002. 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 Wright & Company at December 31, 2004 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, 2004 prices. An analysis of the change in estimated quantities of natural gas and oil reserves from January 1, 2004 to December 31, 2004, 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	180,998,000	3,029,000
Revisions of previous estimates	(10,635,000)	305,000
Beginning of year as revised	170,363,000	3,334,000
New discoveries and extensions		
Rocky Mountain region	40,716,000	358,000
Dispositions to partnerships	(4,240,000)	(12,000)
Acquisitions		
Michigan Basin	96,000	-
Rocky Mountain region	242,000	17,000
Appalachian basin	744,000	-
Production	(10,372,000)	(381,000)
End of year	197,549,000	3,316,000
Proved developed reserves:		
Beginning of year	134,936,000	2,889,000
End of year	146,152,000	3,190,000

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, 2004 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.

	As of December 31, 2004
Future estimated revenues	$1,298,394,000
Future estimated production costs	(319,065,000)
Future estimated development costs	(95,498,000)
Future estimated income tax expense	(332,497,000)
Future net cash flows	551,334,000
10% annual discount for estimated timing of cash flows	(317,099,000)
Standardized measure of discounted future estimated net cash flows	$ 234,235,000

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows from January 1, 2004 through December 31, 2004:

Sales of oil and natural gas production, net of production costs	$(52,974,000)
Net changes in prices and production costs	36,656,000
Extensions, discoveries and improved recovery, less related costs	135,816,000
Dispositions to partnerships	(16,782,000)
Acquisitions	6,451,000
Development costs incurred during the period	36,870,000
Revisions of previous quantity estimates	(34,611,000)
Changes in estimated income taxes	(66,790,000)
Accretion of discount	(27,691,000)
	$16,945,000

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, as 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 the limitations inherent therein.

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 of Notes to Consolidated Financial Statements.

Oil and Natural Gas Leases

The following table sets forth, as of December 31, 2004, the acres available for development of oil and natural gas available to the Company, listed alphabetically by state.

Colorado	105,200
Kansas	21,250
Michigan	1,700
New York	10,000
Wyoming	26,380
Total	164,530

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 site. The Company also owns a field operating building in Weld County, Colorado and one in Gilmer County, West Virginia. The Company leases field operating offices in Colorado, Michigan and Pennsylvania under operating leases.

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 Company's Common Stock and Related Stockholders Matters

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
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
2003		
First Quarter	$ 6.30	$ 5.30
Second Quarter	9.70	6.16
Third Quarter	12.33	8.63
Fourth Quarter	25.05	12.09

As of March 21, 2005, there were approximately 922 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 Condensed Financial Data (1)

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Revenues					
Oil and gas well drilling operations	$119,210,500	$71,841,500	$57,149,100	$76,291,200	$43,194,700
Oil and gas sales	161,179,100	120,162,700	69,223,000	92,095,300	90,419,700
Well operations income	8,384,500	7,347,700	6,116,200	5,604,200	5,061,600
Other income	1,945,700	3,499,100	2,853,600	3,132,400	2,540,500
Total	$290,719,800	$202,851,000	$135,341,900	$177,123,100	$141,216,500
Costs and Expenses (excluding interest and depreciation, depletion and amortization)	$217,284,200	$152,445,000	$108,816,600	$144,468,600	$118,813,300
Interest Expense	$ 874,300	$ 1,329,100	$ 1,339,800	$ 993,400	$1,186,000
Depreciation, depletion and Amortization	$17,958,200	$14,153,400	$12,103,300	$10,578,300	$6,943,500
Net Income	$34,060,600	$22,619,100	$ 9,284,800	$14,967,800	$10,681,000
Basic earnings per common Share	$2.10	$1.45	$.59	$.92	$.66
Diluted earnings per share	$2.05	$1.39	$.58	$.90	$.65
Average Common and Common equivalent Shares Outstanding during the Year	16,647,174	16,297,793	16,143,414	16,639,634	16,437,488

	December 31,				
	2004	2003	2002	2001	2000
Total Assets	$341,393,,000	$306,722,000	$212,251,600	$199,852,100	$187,684,500
Working Capital	$(536,300)	$ 6,230,700	$ 1,770,500	$ 3,419,600	$ 780,700
Long-Term Debt, excluding current maturities	$21,000,000	$ 53,000,000	$ 25,000,000	$ 28,000,000	$ 17,350,000
Stockholders' Equity	$ 164,672,900	$123,604,600	$101,122,200	$ 96,772,800	$ 82,256,900

(1) See Consolidated Financial Statements elsewhere herein.

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 and drilling rigs at reasonable prices; 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 hedging activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-K.

Results of Operations

Management Overview

The Company had record revenues and income for 2004. 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 Riley Natural Gas, 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, revenues, and gross profit for the drilling and development segment. The new wells drilled for the partnerships also led to an increase in revenues for operating wells for the partnerships and others.

The higher level of partnership investments also increased the costs associated with the drilling and development and well operations activities since more goods, services and other costs were required to drill and produce the greater number of wells. Similarly higher oil and natural gas prices also increased the cost of purchasing gas for resale by Riley Natural Gas.

Increased profitability and cash flow from operations allowed the Company to reduce its long term debt and to continue to invest in capital projects. The majority of capital investment was for oil and gas drilling and development activities. The Company also constructed an office building in Colorado for the Company's field operations in the area.

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

Revenues

Total revenues for the year ended December 31, 2004 were $290.7 million compared to $202.9 million for the year ended December 31, 2003, an increase of approximately $87.8 million, or 43.3 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 $119.2 million compared to $71.8 million for the year ended December 31, 2003, an increase of approximately $47.4 million or 66.0 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 $93.2 million compared to $73.1 million for the year ended December 31, 2003, an increase of approximately $20.1 million or 27.5 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 $67.9 million compared to $47.0 million for the year ended December 31, 2003, an increase of $20.9 million or 44.5 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 $5.26 compared to 8.7 million Mcf at an average sales price of $4.42 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 sales price of $35.13 per barrel compared to 289,000 barrels at an average sales price of $29.39 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 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	$35.13	$5.26	$5.37	$29.39	$4.42	$4.50

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

Oil and Gas Hedging Activities

Because of uncertainty surrounding natural gas prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2006 we have in place a series of floors and ceilings on part of our natural gas 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 current positions in effect on the Company's share of production 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 Hedges - (Appalachian and Michigan Basins)				
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 Hedges (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 Hedges (Wattenberg)				
7/04	Jan 2005 – Mar 2005	80,000	$5.00	40,000	$6.20
	NYMEX Based Hedges (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 (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 was $8.4 million compared to $7.3 million for the year ended December 31, 2003, an increase of approximately $1.1 million or 15.1 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 $1.9 million compared to $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 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 $236.1 million compared to $167.9 million for the year ended December 31, 2003, an increase of approximately $68.2 million or 40.6 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 $102.8 million compared to $61.3 million for the year ended December 31, 2003, an increase of approximately $41.5 million or 67.7 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 13.7% compared with 14.7% for the year ended December 31, 2003, a decrease in gross margin of approximately 1%. 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.

Cost of Gas Marketing Activities

The cost of gas marketing activities for the year ended December 31, 2004 were $91.9 million compared to $72.4 million for the year ended December 31, 2003, an increase of $19.5 million or 26.9 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 $689,000 for the year ended December 31, 2003 to $1,324,000 for the year ended December 31, 2004. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production Costs

Oil and gas production costs from the Company's producing properties for the year ended December 31, 2004 were $18.0 million compared to $13.7 million for the year ended December 31, 2003, an increase of approximately $4.3 million or 31.4% 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 $.98 per Mcfe to $1.18 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 $4.9 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 $18.0 million from approximately $14.2 million for the year ended December 31, 2003, an increase of approximately $3.8 million or 26.8 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 costs for the year ended December 31, 2004 were $874,000 compared to $1.3 million for the year ended December 31, 2003, a decrease of $426,000 or 32.8 percent. Such decrease is due to 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.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from 34.7% for the year ended December 31, 2003 to 37.62% 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 fuel source tax credit.

Net income and Earnings Per Share

Net income for the year ended December 31, 2004 was $34.1 million compared to a net income of $22.6 million for the year ended December 31, 2003, an increase of approximately $11.5 million or 50.9 percent.

Diluted earnings per share for the year ended December 31, 2004 was $2.05 per share compared to $1.39 per share for the year ended December 31, 2003, an increase of $.66 per share or 47.5 percent.

Year Ended December 31, 2003 Compared with December 31, 2002

Revenues

Total revenues for the year ended December 31, 2003 were $202.9 million compared to $135.3 million for the year ended December 31, 2002, an increase of approximately $67.6 million, or 50.0 percent. Such increase was a result of increased drilling revenues, gas sales from gas marketing activities, oil and gas sales and well operations and pipeline income.

Drilling Revenue

Drilling revenues for the year ended December 31, 2003 were $71.8 million compared to $57.1 million for the year ended December 31, 2002, an increase of approximately $14.7 million or 25.7 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The four drilling programs of 2003 raised $78.3 million compared to $56.9 million in 2002. We believe this increase is fueled by the increase in oil and natural gas prices which has improved the performance of our prior programs which in turn has helped to increase our 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, 2003 were $73.1 million compared to $46.4 million for the year ended December 31, 2002, an increase of approximately $26.7 million or 57.5 percent. Such increase was due to natural gas sold at significantly higher average sales prices offset in part by slightly lower volumes sold.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the year ended December 31, 2003 were $47.0 million compared to $22.9 million for the year ended December 31, 2002, an increase of $24.1 million or 105.2 percent. The increase was due to significantly increased 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, 2003 was 8.7 million Mcf at an average sales price of $4.42 per Mcf compared to 6.5 million Mcf at an average sales price of $2.68 per Mcf for the year ended December 31, 2002. Oil sales were 289,000 barrels at an average sales price of $29.39 per barrel for the year ended December 31, 2003 compared to 227,000 barrels at an average sales price of $24.41 per barrel for the year ended December 31, 2002. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily the Williams property acquisition in the second quarter, recompletions of existing wells, two fourth quarter acquisitions of oil and gas properties in Colorado and Kansas and to a lesser extent the investment in oil and gas properties we own with our public drilling program partnerships. The table below outlines our increased production in Mcf equivalents of our 2003 recompletions and acquisitions by quarter.

	Mcfe				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Recompletions	40,000	161,000	223,000	285,000	709,000
Williams Acquisition	-	453,000	573,000	519,000	1,545,000
4th Quarter Acquisitions	-	-	-	196,000	196,000
	40,000	614,000	796,000	1,000,000	2,450,000

Oil and Gas Production

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

	Year Ended December 31, 2003			Year Ended December 31, 2002		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	3,992	1,921,200	1,945,152	5,814	2,095,903	2,130,787
Michigan Basin	6,627	1,832,737	1,872,499	8,443	2,146,101	2,196,759
Rocky Mountains	278,874	4,958,245	6,631,489	212,779	2,220,033	3,496,707
Total	289,493	8,712,182	10,449,140	227,036	6,462,037	7,824,253
Average Price	$29.39	$4.42	$4.50	$24.41	$2.68	$2.92

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

Oil and Gas Hedging Activities

Because of uncertainty surrounding natural gas prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2005 we have in place a series of floors and ceilings on part of our natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. During the three months ended December 31, 2003 the Company averaged natural gas volumes sold of 857,000 Mcf per month and oil sales of 31,400 barrels per month. The current positions in effect on the Company's share of production are shown in the following table.

	Floors		Ceilings	
Month	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
NYMEX Based Hedges - (Appalachian and Michigan Basins)				
Jan 2004	114,000	$4.45	57,000	$5.40

Feb 2004	114,000	$4.30	57,000	$5.25
Mar 2004	114,000	$4.20	57,000	$5.00
Apr 2004 - Oct 2004	81,000	$4.00	81,000	$5.65
Apr 2004 - Oct 2004*	122,000	$5.00	-	-
Apr 2005 - Oct 2005*	122,000	$4.28	61,000	$5.00
Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)				
Jan 2004 - Mar 2004	20,000	$3.50	20,000	$5.25
Apr 2004 - Oct 2004	25,000	$3.20	25,000	$4.70
Apr 2004 - Oct 2004*	25,000	$4.17	-	-
Apr 2005- Oct 2005*	33,000	$3.10	16,000	$4.43
NYMEX Based Hedges (Williams acquisition)				
Jan 2004 - Dec 2004	150,000	$4.50	-	-
Apr 2005 - Oct 2005*	150,000	$4.26	75,000	$5.00

Oil hedges (Wattenberg Field)

Month	Monthly Quantity Bbl	Contract Price
Mar 2004 - Dec 2004*	10,000	$31.60

*Entered into during 2004

Well Operations, Pipeline & Other Income

Well operations and pipeline income for the year ended December 31, 2003 was $7.3 million compared to $6.1 million for the year ended December 31, 2002, an increase of approximately $1.2 million or 19.7 percent. Such increase was due to an increase in the number of wells and pipeline systems operated by the Company for our Drilling Fund Partnerships as well as joint ventures. Other income for the year ended December 31, 2003 was $3.5 million compared to $2.9 million for the year ended December 31, 2002. Such increase was due to receiving the proceeds of $1.0 million in life insurance offset in part by a reduction in sales of miscellaneous items.

Costs and Expenses

Costs and expenses for the year ended December 31, 2003 were $167.9 million compared to $122.3 million for the year ended December 31, 2002, an increase of approximately $45.6 million or 37.3 percent. Such 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, 2003 were $61.3 million compared to $49.2 million for the year ended December 31, 2002, an increase of approximately $12.1 million or 24.6 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above.

Cost of Gas Marketing Activities

The cost of gas marketing activities for the year ended December 31, 2003 were $72.4 million compared to $46.2 million for the year ended December 31, 2002, an increase of $26.2 million or 56.7 percent. The increase was due to the significantly higher average prices of natural gas purchased and offset in part by slightly lower volumes purchased for resale. Income before income taxes for the Company's natural gas marketing subsidiary improved from $174,000 for the year ended December 31, 2002 to $689,000 for the year ended December 31, 2003. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production Costs

Oil and gas production costs from the Company's producing properties for the year ended December 31, 2003 were $13.7 million compared to $9.1 million for the year ended December 31, 2002, an increase of approximately $4.6 million or 50.5% 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 $.82 per Mcfe to $.98 per Mcfe which is almost entirely attributed to the increase in severance and property taxes on the significantly increased oil and gas sales prices.

General and Administrative Costs

General and administrative expenses for the year ended December 31, 2003 increased to $4.9 million compared with $4.4 million for the year ended December 31, 2002 an increase of approximately $500,000 or 11.4%, such increase was due to the increased administrative activity associated with a growing Company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the year ended December 31, 2003 increased to $14.2 million from approximately $12.1 million for the year ended December 31, 2002, an increase of approximately $2.1 million or 17.4%. 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 costs for the year ended December 31, 2003 and 2002 were $1.3 million. The lower average effective interest rates in 2003 more than offset the higher average borrowing levels the Company experienced during 2003, primarily a result of the oil and gas property acquisitions mentioned above.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from 29% to 34.7% primarily as a result of the expired non-conventional source fuel tax credit and the effect of the federal rate change to 35% because of significantly increased earnings of the Company during 2003.

Change in Accounting Principle

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

Net income and Earnings Per Share

Net income for the year ended December 31, 2003 was $22.6 million compared to a net income of $9.3 million for the year ended December 31, 2002, an increase of approximately $13.3 million or 143% percent.

Diluted earnings per share for the year ended December 31, 2003 was $1.39 per share compared to $.58 per share for the year ended December 31, 2002, an increase of $.81 per share or 139.7 percent.

Liquidity and Capital Resources

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

Natural Gas Pricing and Pipeline Capacity

Natural gas and oil prices have been volatile in the past, and are expected to show continued volatility in the future. Currently, the NYMEX futures reflect a market expectation of gas prices at Henry Hub close to or above record prices per million Btu's (Mmbtu) in 2005. Natural gas prices look strong for 2005 even though natural gas storage levels are above normal levels following a period when storage levels had been at a five-year low. Domestic and international demand for energy has been increasing in the past several years, particularly in China and some other developing countries. At the same time it does not currently seem that new supplies have kept up with the growing demand. The Company's management believes this situation creates the possibility of both periods of low prices and continued high prices.

Natural gas prices were at historically high levels throughout 2003 and 2004 in our Appalachian and Michigan producing areas. Natural gas prices in Colorado were low for most of 2002. In the fourth quarter of 2002 and continuing through 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. We believe that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 77% to over 90% of the NYMEX price, levels consistent with historical price relationships before the local demand/pipeline capacity problem described above.

Oil Pricing

Oil prices have strengthened since the middle of 2003. While oil prices are influenced by supply and demand, global geopolitics may be the single most important determinant. Since the percentage of the Company's production reflected by oil sales has increased to approximately 20% during the year ended December 31, 2004, variations in oil prices will have a greater impact on the Company than in the past. See previous pages in this Management's Discussion and Analysis for a complete schedule of current hedging positions.

Oil and Gas Hedging Activities

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

The Company hedges prices for its partners' share of production as well as its own production. Actual wellhead prices will vary based on local contract conditions, gathering and other costs and factors.

Public Drilling Programs

The Company closed four public drilling partnerships during 2004. The total amount received during 2004 was $100 million compared to $78.3 million for 2003. As the year progressed interest in our programs continued to increase. The last three drilling partnerships of 2004 closed at their maximum allowable subscriptions, each earlier than the scheduled close. The Company proceeded with drilling for each of these partnerships as rigs, leases and other resources were available. Because the Company was unable to complete all of the drilling and completion activities for the partnerships formed in 2004 during the year, the Company has a drilling carryover to 2005 of $42.5 million compared with $50.5 million at the end of 2003. The response to the Company's first program of 2005 was even more positive than the response to the 2004 program. It was opened on January 3, 2005 and was scheduled to close on April 30, 2005, but was fully committed with $40 million in subscriptions within a few days of the opening. Additional programs are scheduled to close in April and September of 2005, with total possible subscriptions of $115 million for the year. The Company invests, as its equity contribution to each drilling partnership, a sum equal to approximately 22% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

The Company posts daily the amount of subscriptions that have been sold in the current 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), only if investors request the Company to repurchase such units and subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $6.6 million. The Company has adequate liquidity to meet this obligation. During 2004 the Company spent $408,300 under this provision.

Drilling Activity

During 2004 the Company drilled along with its public drilling fund partnerships a total of 137 wells with only four developmental dry holes. The Company drilled 97 successful wells in its Wattenberg field in the Denver-Julesburg Basin and 36 successful wells in the Piceance Basin in western Colorado, all of the wells that the Company drills in these two areas are in conjunction with its public drilling fund partnerships. The Company plans to conduct the remainder of its 2004 partnership drilling activity in these two areas.

In the fourth quarter of 2004, the Company began drilling on a planned 20 well program on its northeast Colorado properties (NECO). The wells are being drilled on locations created by the regulatory approval of the reduction in well spacing from 80 to 40 acres on the properties the Company acquired in Yuma County in 2003. All twenty of the wells have been successful and are now in production.

The Company drilled one exploratory well in 2004 and plans additional exploratory wells in 2005. As of the date of this report, the exploratory well had been completed and testing was underway but the well had not been classified as successful or dry. Testing of the well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing in the second quarter. If the well is determined to be a dry hole, its costs will be expensed in the period when the determination is made as required by the successful efforts method of accounting. The cost of the well as of January 31, 2005 is $4,362,000. Currently the Company plans to retain most if not all of the working interest in the exploratory wells, since the Company partnerships focus on developmental activities and are allowed only limited participation in exploratory drilling.

Purchase of Oil and Gas Properties

Although the Company made several offers to purchase producing oil and gas properties from other companies during 2004, it was not successful in purchasing any of those properties. The Company did purchase a number of small interests in its partnerships from investors wishing to liquidate their holdings under the repurchase provision of the partnerships.

Costs incurred by the Company in oil and gas acquisitions, exploration and development for the year ended December 31, 2004 are presented below:

Property acquisition cost:	
Proved undeveloped properties	$4,583,000
Producing properties	720,000
Development costs	36,870,400
	$42,173,400

Common Stock Repurchase

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

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

Long-Term Debt

The Company has a credit facility with J. P. Morgan Chase Bank NA and BNP Paribas of $100 million subject to and secured by adequate levels of oil and gas reserves. The current total borrowing base is $80.0 million of which the Company has activated $60 million of the facility. The Company is required to pay a commitment fee of 1/4 percent on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2008.

As of December 31, 2004 the outstanding balance was $21,000,000 . Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. As of December 31, 2004 the Company was in compliance with all financial covenants in the credit agreement. At December 31, 2004, the outstanding balance was subject to a prime rate of 5.25%.

Contractual Obligations

Contractual obligations and due dates are as follows:

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$21,000,000	-	-	$21,000,000	-
Operating Leases	895,700	$307,900	$363,300	172,500	$52,000
Asset Retirement Obligation	783,500	50,000	50,000	50,000	633,500
Drilling Rig Commitment	1,604,250	1,604,250	-	-	-
Other Liabilities	3,967,500	40,000	1,287,000	250,000	2,390,500
Total	$28,250,950	$2,002,150	$1,700,300	$21,472,500	$3,076,000

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 costs efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

Commitments and Contingencies

As Managing General Partner of 10 private partnership and 62 public 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 listing is not a comprehensive list of all of our accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by accounting principles generally accepted in the United States, with no need for management's judgment in their application. There are also areas in which management's judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and may require the application of significant judgment by our management; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, our management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on our historical experience, our observance of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see “Note 1 - Summary of significant account policies” in our financial statements and related notes. Our critical accounting policies and estimates are as follows:

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our publicly registered drilling programs using the percentage of completion method. These contracts are footage rate based and completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services. The percentage of completion method measures the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed continually during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts would be recorded at the time that our estimated costs exceeded the contract revenue. The Company has not experienced any contract losses in 2004, 2003 or 2002.

Natural gas marketing is recorded on the gross accounting method. Riley Natural Gas (“Riley”), our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. Riley has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because Riley takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership.

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

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

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

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

Valuation of Accounts Receivable

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

Accounting for Derivatives Contracts at Fair Value

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

Derivatives are reported on the Consolidated Balance Sheets at fair value. Changes in fair value of derivatives that are not designated as accounting hedges are recorded in earnings.

The measurement of fair value is based on actively quoted market prices, if available. Otherwise, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based on valuation methodologies considered appropriate by the Company's management.

For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value. In addition, for hedges of forecasted transactions, the Company must estimate the expected future cash flows of the forecasted transactions, as well as evaluate the probability of the occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could affect the timing of recognition in earnings for changes in fair value of certain hedging derivatives.

Use of Estimates in Long-Lived Asset Impairment Testing

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

Oil and Gas Properties

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

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

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

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

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

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds or salvage value, is credited or charged to income. Upon sale of a partial unit of property, the proceeds are credited to accumulated depreciation and depletion.

Deferred Tax Asset Valuation Allowance

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

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

New Accounting Standards

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

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

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), “Share-Based Payment” which is a revision of FASB Statement No. 123, “Accounting for Stock-Based Compensation”. Statement 123R supercedes APB opinion No. 25, “Accounting for Stock Issued to

Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The provisions of this statement becomes effective for our third quarter 2005. Management has not determined the impact that this statement will have 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, 2004 is $99,753,700 with an average interest rate of 1.14%. As of December 31, 2004, the Company had long-term debt of $21,000,000 subject to a prime rate of 5.25%.

Commodity Price Risk

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

The following tables summarize the open futures and options contracts for Riley Natural Gas and PDC as of December 31, 2004 and 2003.

Riley Natural Gas
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of December 31, 2004					
Natural Gas	Sale	3,260,000	$5.60	$18,249,250	($1,982,964)
Natural Gas	Purchase	1,130,000	$6.77	$7,644,540	($486,490)
Natural Gas	Floor	530,000	$5.30		$134,242
Natural Gas	Ceiling	265,000	$7.00		($85,541)
Contracts maturing in 12 months following December 31, 2004					
Natural Gas	Sale	2,230,000	$5.84	$13,014,810	($841,102)
Natural Gas	Purchase	860,000	$6.94	$5,965,490	($591,340)
Natural Gas	Floor	530,000	$5.30		$134,242
Natural Gas	Ceiling	265,000	$7.00		($85,541)

Prior Year Total Contracts as of December 31, 2003					
Natural Gas	Sale	2,660,000	$4.58	$12,174,130	($1,943,680)
Natural Gas	Purchase	820,000	$5.17	$4,243,420	$451,020

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

Petroleum Development Corporation
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of December 31, 2004					
Natural Gas	Purchase	46,776	$6.63	$310,339	($17,806)
Natural Gas	Floor	3,562,020	$4.56		$337,842
Natural Gas	Ceiling	1,556,010	$5.39		($1,526,868)
Crude Oil	Floor	166,536	$32.30		$141,880
Crude Oil	Ceiling	83,268	$40.00		($450,405)
Contracts maturing in 12 months following December 31, 2004					
Natural Gas	Sale				
Natural Gas	Purchase	46,776	$6.63	$310,339	($17,806)
Natural Gas	Floor	3,562,020	$4.56		$337,842
Natural Gas	Ceiling	1,556,010	$5.39		($1,526,868)
Crude Oil	Floor	166,536	$32.30		$141,880
Crude Oil	Ceiling	83,268	$40.00		($450,405)
Prior Year Total Contracts as of December 31, 2003					
Natural Gas	Sale	54,572	$5.40	$294,689	($40,871)
Natural Gas	Purchase	46,776	$4.77	$223,122	$31,051
Natural Gas	Floor	3,023,800	$4.25		$185,486
Natural Gas	Ceiling	1,060,300	$5.31		($172,377)

The maximum term over which PDC is hedging exposure to the variability of cash flows for commodity price risk is 12 months.

The average NYMEX closing price for natural gas for the years 2004, 2003, and 2002 was $6.14, $5.39 Mmbtu, and $3.22 Mmbtu. The average NYMEX closing price for oil for the years 2004, 2003, 2002 was $41.44, $30.98 bbl, and $26.98 bbl. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

Disclosure of Limitations

As the information above incorporates only those exposures that exist at December 31, 2004, 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) Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer conducted an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this report.

(b) Management's Report on Internal Control over Financial Reporting

The management of Petroleum Development Corporation is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)). Petroleum Development Corporation's internal control system is designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

Petroleum Development Corporation's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2004.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 has been audited by KPMG LLP, the independent registered public accounting firm that also audited the Company's consolidated financial statements. KPMG LLP's attestation report on management's assessment of the Company's internal control over financial reporting appears below.

(c) Changes in Internal Control over Financial Reporting

There were no significant changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2004 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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(b)), that Petroleum Development Corporation (the Company) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Petroleum Development Corporation'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.

In our opinion, management's assessment that Petroleum Development Corporation maintained effective internal control over financial reporting as of December 31, 2004, 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, Petroleum Development Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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, 2004 and 2003, and the related consolidated statements of income, stockholders' equity and comprehensive income (loss) and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 30, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Pittsburgh, Pennsylvania
March 30, 2005

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	53	Chairman and Chief Executive Officer,	January 2004
		and Director	March 1983
Thomas E. Riley	52	President	December 2004
		Director	November 2003
Darwin L. Stump	49	Chief Financial Officer and Treasurer	November 2003
Eric R. Stearns	47	Executive Vice President Exploration and Development	November 2003
Gregory A. Morgan	46	Secretary	September 2004
Vincent F. D'Annunzio	52	Director	February 1989
Jeffrey C. Swoveland	49	Director	March 1991
Donald B. Nestor	56	Director	March 2000
Kimberly Luff Wakim	46	Director	January 2003
David C. Parke	38	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 PDC 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 PDC since April 1996. Prior to joining PDC, Mr. Riley was president of Riley Natural Gas Company, a natural gas marketing company which PDC 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 PDC.

Eric R. Stearns was appointed Executive Vice President of Exploration and Development in November 2003. Prior thereto, Mr. Stearns was Vice President of Exploration and Development since April 1995. Mr. Stearns joined PDC 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 PDC, but his law firm provides legal services to PDC.

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. Swoveland and Mr. Parke are members of the class whose term expires in 2005. 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. 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 such 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 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. 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 Jeffrey C. Swoveland chairs the Compensation Committee.

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

There is incorporated by reference herein in response to this Item the material under the heading "Election of Directors - Remuneration of Directors and Officers", "Election of Directors - Stock Options" and "Election of Directors - Interest of Management in Certain Transactions" in the Company's definitive proxy statement for its 2005 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2005.

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

There is incorporated by reference herein in response to this Item, the material under the heading "Election of Directors", in the Company's definitive proxy statement for its 2005 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2005.

The Company has the following common stock options outstanding under the stock option plans approved by the stockholders:

Equity Compensation Plan Information
December 31, 2004

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	76,880	$11.64	733,120
Equity compensation plans not approved by security holders	-	-	-
Total	76,880	$11.64	733,120

Item 13. Certain Relationships and Related Transactions

The response to this item is set forth herein in Note 8 in the Notes to Consolidated Financial Statements and under "Election of Directors - Interest of Management in Certain Transactions," in the Company's definitive proxy statement for its 2005 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2005, which we incorporate by reference.

Item 14. Principal Accounting Fees and Services

The information under the caption "Fees Billed by Independent Public Accountants for Services in 2004 and 2003" in the Company's definitive Proxy Statement in connection with the 2005 annual stockholders' meeting is incorporated by reference.

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(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

March 31, 2005

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 Steven R. Williams	Chairman, Chief Executive Officer and Director	March 31, 2005
/s/ Darwin L. Stump Darwin L. Stump	Chief Financial Officer and Treasurer (principal financial and accounting officer)	March 31, 2005
/s/ Thomas E. Riley Thomas E. Riley	President and Director	March 31, 2005
/s/ Donald B. Nestor Donald B. Nestor	Director, Chairman of Audit Committee	March 31, 2005
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	March 31, 2005
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	March 31, 2005
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	March 31, 2005
/s/ David C. Parke David C. Parke	Director	March 31, 2005

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
Credit Agreement, dated as of July 3, 2002, as extended as of April 30, 2004 by and between Petroleum Development Corporation and the lenders, Bank One N.A. and BNP Paribas	10.1	Incorporated by reference to Exhibit 10.1 to Form 10-K for year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003
Employment Agreement with Steven R. Williams, Chief Executive Officer and Chairman, dated as of March 7, 2003	10.2	Incorporated by reference in Exhibit 10.2 to Form 10-K filed on March 7, 2003
Employment Agreement with Darwin L. Stump, Chief Financial Officer, dated as of January 5, 2004	10.3	Incorporated by reference to Exhibit 99.4 Form 8-K dated January 5, 2004
Employment Agreement with Thomas E. Riley, President, dated as of January 5, 2004	10.4	Incorporated by reference to Exhibit 99.6 Form 8-K dated January 5, 2004
Employment Agreement with Eric R. Stearns, Executive Vice President, dated as of January 5, 2004	10.5	Incorporated by reference to Exhibit 99.5 Form 8-K dated January 5, 2004
2004 Long-Term Equity Compensation Plan	10.6	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	10.7	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	10.8	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	10.9	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	10.10	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.
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	32.1	Filed herewith.

Officer and Chief Financial Officer

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

Form 8-K current report dated December 16, 2004, under item 1.01 Entry into a Material Definitive Agreement, the Compensation Committee of Petroleum Development Corporation has established 2004 grants for the executive officers of the company (the Participants). The grants are being awarded pursuant to the terms of the Petroleum Development Corporation 2004 Long-Term Equity Compensation Plan that was approved by the shareholders of the company at the June 11, 2004 Annual Meeting.

Form 8-K/A current report dated December 15, 2004, under Item 5.02. Any resignation, appointment, retirement, removal or termination of a director or executive officer or any director's refusal to stand for reelection. The Company issued a news release announcing that Thomas E. Riley has been selected as President of the Company filling the position currently held by Steven R. Williams. Mr. Williams will remain CEO and Chairman of PDC.

Form 8-K current report dated December 15, 2004, under Item 5 Other Events, the Company issued a news release announcing that Thomas E. Riley has been selected as President of the Company filling the position currently held by Steven R. Williams. Mr. Williams will remain CEO and Chairman of PDC.

Form 8-K current report dated November 5, 2004, under Item 2.02 Results of Operations and Financial Condition, the Company issued a news release announcing financial and operating results for the third quarter 2004.

Form 8-K current report dated October 29, 2004, under Item 8.01. Other Events, the Company issued a news release announcing upcoming earnings release and invites you to join its third quarter earnings web cast.

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, 2004 and 2003, and the related consolidated statements of income, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2004. In connection with our audits of the consolidated financial statements, we also have audited 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, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U. S. generally 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 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, 2004, 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 March 30, 2005, expressed an unqualified opinion on management's assessment of, and effective operation of, internal control over financial reporting.

KPMG LLP

Pittsburgh, Pennsylvania
March 30, 2005

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2004 and 2003

Assets	2004	2003
Current assets:		
Cash and cash equivalents	$77,070,400	$ 78,512,900
Restricted cash	664,900	1,866,400
Notes and accounts receivable	33,902,800	23,067,000
Inventories	1,657,300	2,014,300
Other current assets	7,334,200	5,907,000
Total current assets	120,629,600	111,367,600
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	291,436,700	251,558,900
Pipelines	9,515,000	9,097,000
Transportation and other equipment	4,453,700	3,460,900
Land and buildings	2,942,800	1,747,500
	308,348,200	265,864,300
Less accumulated depreciation, depletion and amortization	88,341,300	71,182,100
	220,006,900	194,682,200
Other assets	756,500	672,200
Total Assets	$341,393,000	$306,722,000

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2004 and 2003

	2004	2003
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$42,438,400	$ 29,453,000
Production tax liability	17,510,500	9,069,400
Other accrued expenses	5,807,900	7,744,800
Advances for future drilling contracts	42,497,300	50,458,800
Funds held for future distribution	12,911,800	8,410,900
Total current liabilities	121,165,900	105,136,900
Long-term debt	21,000,000	53,000,000
Other liabilities	3,927,500	2,449,100
Deferred income taxes	29,843,200	21,800,200
Asset retirement obligation	783,500	731,200
Commitments and contingencies (Note 9)		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 16,589,324 and 15,628,433 shares	165,800	156,200
Additional paid-in capital	37,684,300	28,592,900
Retained earnings	130,109,800	96,049,200
Unamortized stock award	(882,000)	(14,800)
Accumulated other comprehensive loss, net of tax	(2,405,000)	(1,178,900)
Total stockholders' equity	164,672,900	123,604,600
Total Liabilities and Stockholders' Equity	$341,393,000	$306,722,000

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Income

Years Ended December 31, 2004, 2003 and 2002

	2004	2003	2002
Revenues:			
Oil and gas well drilling operations	$119,210,500	71,841,500	57,149,100
Gas sales from marketing activities	93,231,400	73,141,100	46,365,900
Oil and gas sales	67,947,700	47,021,600	22,857,100
Well operations and pipeline income	8,384,500	7,347,700	6,116,200
Other income	1,945,700	3,499,100	2,853,600
	290,719,800	202,851,000	135,341,900
Costs and expenses:			
Cost of oil and gas well drilling operations	102,830,700	61,277,800	49,166,200
Cost of gas marketing activities	91,898,100	72,443,600	46,184,300
Oil and gas production and well operations costs	18,049,800	13,749,200	9,074,200
General and administrative expenses	4,505,600	4,974,400	4,391,900
Depreciation, depletion and amortization	17,958,200	14,153,400	12,103,300
Interest	874,300	1,329,100	1,339,800
	236,116,700	167,927,500	122,259,700
Income before income taxes and cumulative effect of change in accounting principle	54,603,100	34,923,500	13,082,200
Income taxes	20,542,500	12,105,800	3,797,400
Net income before cumulative effect of change in accounting principle	34,060,600	22,817,700	9,284,800
Cumulative effect of change in accounting principle (net of taxes of $121,700)	-	(198,600)	-
Net income	$34,060,600	22,619,100	9,284,800
Basic earnings per common share before accounting change	$2.10	1.46	.59
Cumulative effect of change in accounting principle	-	(0.01)	-
Basic earnings per common share	$2.10	1.45	.59
Diluted earnings per share before accounting change	$2.05	1.40	.58
Cumulative effect of change in accounting principle	-	(0.01)	-
Diluted earnings per common and common equivalent share	$2.05	1.39	.58

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss)

Years Ended December 31, 2004, 2003 and 2002

	Common stock issued						
	Number Of Shares	Amount	Additional Paid-in-capital	Retained Earnings	Unamortized Stock Award	Accumulated Other Comprehensive Income (loss)	Total
Balance, December 31, 2001	16,245,752	$ 162,400	32,951,700	64,145,300	(29,200)	(457,400)	96,772,800
Issuance of common stock:							
Exercise of employee stock options	70,000	700	78,100	-		-	78,800
Amortization of stock award		-		-	5,500	-	5,500
Repurchase and cancellation of treasury stock	(580,985)	(5,800)	(3,689,300)				(3,695,100)
Net income	-	-	-	9,284,800	-	-	9,284,800
Comprehensive income:							
Reclassification adjustment for settlement of contracts Included in net income (net of tax of $9,100)	-	-	-	-	-	14,800	
Changes in fair value of outstanding hedging positions and interest rate swap (net of tax of $820,900)	-	-	-	-	-	(1,339,400)	
Other comprehensive loss						(1,324,600)	(1,324,600)
Comprehensive income							7,960,200
Balance, December 31, 2002	15,734,767	157,300	29,340,500	73,430,100	(23,700)	(1,782,000)	101,122,200
Amortization of stock award		-		-	8,900	-	8,900
Repurchase and cancellation of treasury stock, net	(106,334)	(1,100)	(747,600)				(748,700)
Net income	-	-	-	22,619,100	-	-	22,619,100
Comprehensive income:							
Reclassification adjustment for settlement of contracts Included in net income (net of tax of $583,900)	-	-	-	-	-	917,200	
Changes in fair value of outstanding hedging positions and interest rate swap (net of tax of $200,000)	-	-	-	-	-	(314,100)	
Other comprehensive income						603,100	603,100
Comprehensive income							23,222,200
Balance, December 31, 2003	15,628,433	156,200	28,592,900	96,049,200	(14,800)	(1,178,900)	123,604,600
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 and cancellation of treasury stock, net	(162,489)	(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	-	-	-	34,060,600	-	-	34,060,600
Comprehensive income:		-	-	-	-	-	
Reclassification adjustment for settlement of contracts Included in net income (net of tax of $2,084,400)	-	-	-	-	-	3,274,000	
Changes in fair value of outstanding hedging positions and interest rate swap (net of tax of $2,865,000)	-	-	-	-	-	(4,500,100)	
Other comprehensive loss	-	-	-	-		(1,226,100)	(1,226,100)
Comprehensive income							32,834,500
Balance, December 31, 2004	16,589,324	$165,800	37,684,300	130,109,800	(882,000)	(2,405,000)	164,672,900

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years Ended December 31, 2004, 2003 and 2002

	2004	2003	2002
Cash flows from operating activities:			
Net income	$34,060,600	22,619,100	9,284,800
Adjustment to reconcile net income to cash provided by operating activities:			
Deferred income taxes	10,443,600	8,870,700	2,986,400
Depreciation, depletion and amortization	17,958,200	14,153,400	12,103,300
Cumulative effect of change in accounting principle	-	198,600	-
Gain from sale of assets	(32,000)	(115,800)	(25,800)
Expired and abandoned leases	344,700	1,418,400	1,129,400
Amortization of stock award	3,700	8,900	5,500
(Increase) in notes and accounts receivable	(10,835,800)	(7,187,100)	(4,583,900)
Decrease (increase) in inventories	357,000	(1,383,600)	(56,200)
Decrease (increase) in other current assets	4,776,200	(1,095,900)	369,200
(Increase) decrease in other assets	(281,300)	1,696,200	56,300
Increase in production tax liability	8,441,100	3,974,800	1,833,400
Increase in accounts payable and accrued expenses	10,091,500	12,782,200	111,800
(Decrease) increase in advances for future drilling contracts	(7,961,500)	13,175,000	5,691,600
Increase (decrease) in funds held for future distribution	4,500,900	4,493,000	(732,900)
Total adjustments	37,806,300	50,988,800	18,888,100
Net cash provided by operating activities	71,866,900	73,607,900	28,172,900
Cash flows from investing activities:			
Capital expenditures	(45,391,800)	(73,042,300)	(19,777,000)
Proceeds from sale of leases to partnerships	1,950,900	1,382,100	1,042,500
Proceeds from sale of fixed assets	94,700	156,800	25,800
Decrease (increase) in restricted cash	1,201,500	894,100	(2,477,200)
Net cash used in investing activities	(42,144,700)	(70,609,300)	(21,185,900)
Cash flows from financing activities:			
(Retirement of) proceeds from debt, net	(32,000,000)	28,000,000	(3,000,000)
Proceeds from issuance of stock	3,584,400	-	78,800
Repurchase and cancellation of treasury stock	(2,749,100)	(748,700)	(3,695,100)
Net cash (used in) provided by financing activities	(31,164,700)	27,251,300	(6,616,300)
Net (decrease) increase in cash and cash equivalents	(1,442,500)	30,249,900	370,700
Cash and cash equivalents, beginning of year	78,512,900	48,263,000	47,892,300
Cash and cash equivalents, end of year	$77,070,400	78,512,900	48,263,000

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

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 limited partnerships under the proportionate consolidation method. Under this method, the Company's financial statements include its prorata share of assets and liabilities and revenues and expenses, respectively, of the limited partnerships in which it participates.

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 19)

The Company grants credit to purchasers of oil and gas and the owners of managed properties, substantially all of whom are located in West Virginia, Tennessee, Pennsylvania, Michigan, North Dakota, Colorado and Kansas.

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 future contracts. As of December 31, 2004 and 2003, cash in the amount of $664,900 and $1,866,400 was on deposit.

Inventories

Inventories of well equipment, parts and supplies are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased in excess of deliveries to customers and is recorded at the lower of cost or market.

Oil and Gas Properties

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

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

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

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

(Continued)

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

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds or salvage value, is credited or charged to income. Upon sale of a partial unit of property, the proceeds are credited to accumulated depreciation and depletion.

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 incurs retirement obligations for its well drilling operations under FASB Statement No. 143, "Accounting for Asset Retirement Obligations". This requires entities to record the fair value of a liability for an asset retirement obligation in the period incurred and a corresponding increase in the carrying amount of the long-lived assets. The costs associated with this liability are capitalized as part of the related long-lived asset and depreciated. The Company adopted FASB No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $198,600 (net of taxes of $121,700). Since adoption the obligation has increased to $783,500 as of December 31, 2004 due to the additional wells purchased and drilled by the Company and accretion, offset in part by wells plugged.

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

(Continued)

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 publicly registered drilling programs using the percentage of completion method. These contracts are footage rate based and completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services. The percentage of completion method measures the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed continually during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts would be recorded at the time that our estimated costs exceeded the contract revenue. The Company has not experienced any contract losses in 2004, 2003, or 2002.

Natural gas marketing is recorded on the gross accounting method. Riley Natural Gas (“Riley”), our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. Riley has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because Riley takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership.

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

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

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

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

(Continued)

Income Taxes

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.

Derivative Financial Instruments

The Company accounts for derivatives and hedging in accordance with FASB Statement No. 133 Accounting for Derivative Instruments and Certain Hedging Activities, as amended which requires that all derivatives be recorded on the consolidated balance sheet at their fair values. On the date the derivative contract is entered into, the Company designates the derivative as either a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability ("Cash flow" hedge), or a non-hedging derivative. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash-flow hedges to specific firm commitments. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, the Company discontinues hedge accounting prospectively. No hedging activities were discontinued during 2004, 2003 or 2002.

Changes in fair value of a derivative that is highly effective and that is designated and qualifies as a cash-flow hedge are recorded in other comprehensive income, until earnings are affected by the variability in cash flows of the designated hedged item. Changes in the fair value of non-hedging derivatives are reported in current-period earnings. The Company discontinues hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised. Additionally, if the derivative is designated as a hedging instrument, and it is subsequently determined to be probable that a forecasted transaction will not occur or management determines that designation of the derivative as a hedging instrument is no longer appropriate, hedge accounting will be discontinued.

The Company uses derivative financial instruments for several purposes. The Company manages its exposure to price fluctuations in selling and producing natural gas by entering into natural gas future contracts and options contracts.

Stock Compensation

The Company applies the intrinsic-value based method of accounting prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations including FASB Interpretation No. 44, "Accounting for Certain Transactions involving Stock Compensation, an interpretation of APB Opinion No. 25", to account for its fixed-plan stock options. Under this method, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. FASB Statement No. 123, "Accounting for Stock-Based Compensation" and FASB Statement No. 148, "Accounting for Stock Based Compensation- Transition and Disclosure, an amendment of FASB Statement No. 123", established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. As permitted by existing accounting standards, the Company has elected to continue to apply the intrinsic-value-based method of accounting described above, and has adopted only the disclosure requirements of Statement 123, as amended. If the fair-value-based method had been applied to all outstanding and unvested awards in each period, the impact in 2004 would have been $18,400. There would have been no impact or reported net income in 2003 or 2002.

(Continued)

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' stock at the date of grant and vesting period.

The pro forma amounts that would have been reported if FASB 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. 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, 2004, there was approximately \$283,000 of total unrecognized, pre-tax compensation cost related to non-vested stock options. This cost is expected to be recognized over four years. The Company will adopt the provisions of FASB Statement No. 123R (revised 2004), Share-Based Payment, in 2005 regarding stock compensation as discussed below. The Company will adopt the provisions of FASB Statement No. 123R (revised 2004), “Share-Based Payment”, in 2005 regarding stock compensation as discussed below. Upon adoption of FASB Statement No. 123R, such cost will be recognized directly in our consolidated statement 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, 2004, 2003 and 2002.

New Accounting Standards

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

(Continued)

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), "Share-Based Payment" which is a revision of FASB Statement No. 123, "Accounting for Stock-Based Compensation". Statement 123R supercedes APB opinion No. 25, "Accounting for Stock Issued to Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The provisions of this statement becomes effective for our third quarter 2005. Management has not determined the impact that this statement will have on our consolidated financial statements.

(2) Notes and Accounts Receivable

Included in other assets are noncurrent accounts receivable as of December 31, 2004 and 2003, in the amounts of $608,500 and $819,700 less of an allowance for doubtful accounts of $244,400 and $338,100, respectively.

The allowance for doubtful current accounts receivable as of December 31, 2004 and 2003 was $164,600 and $149,200, 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 $100 million subject to and secured by adequate levels of oil and gas reserves. The current total borrowing base is $80.0 million of which the Company has activated $60 million of the facility. The Company is required to pay a commitment fee of 1/4 percent on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2008.

As of December 31, 2004 and 2003 the outstanding balance was $21,000,000 and $53,000,000, 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. As of December 31, 2004 and 2003 the Company was in compliance with all financial covenants in the credit agreement. At December 31, 2004, the outstanding balance was subject to a prime rate of 5.25%.

(4) Income Taxes

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

	2004	2003	2002
Current:			
Federal	$8,426,400	2,401,000	604,200
State	1,672,500	834,100	206,800
Total current income taxes	10,098,900	3,235,100	811,000
Deferred:			
Federal	8,900,300	7,802,800	2,461,200
State	1,543,300	1,067,900	525,200
Total deferred income taxes	10,443,600	8,870,700	2,986,400
Total income taxes	$20,542,500	12,105,800	3,797,400

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 35 percent in 2004 and 2003 and 34 percent in 2002 to pretax income as a result of the following:

(Continued)

	2004	2003	2002
Computed "expected" tax	$19,111,100	12,223,200	4,447,900
State income tax	2,129,500	1,362,000	483,100
Percentage depletion	(794,100)	(935,000)	(680,000)
Nonconventional source fuel credit	-	(186,600)	(491,500)
Officers life insurance	-	(360,000)	-
Surtax exemption	-	(100,000)	-
Change in federal rate bracket	-	254,700	-
Other	96,000	(152,500)	37,900
	$20,542,500	12,105,800	3,797,400

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2004 and 2003 are presented below:

	2004	2003
Deferred tax assets:		
Allowance for doubtful accounts	$ 159,100	189,500
Drilling notes	57,200	73,500
Alternative minimum tax credit carryforwards (Section 29)	-	437,400
Future abandonment	725,500	614,900
Deferred compensation	692,100	1,784,200
Asset Retirement Obligations	121,700	121,700
Accumulated Other Comprehensive Income	1,531,200	750,500
Other	21,800	27,700
Total gross deferred tax assets	3,308,600	3,999,400
Less valuation allowance	-	-
Deferred tax assets	3,308,600	3,999,400
Less current deferred tax assets (included in other current assets)	(337,300)	(1,957,400)
Net non-current deferred tax assets	2,971,300	2,042,000
Deferred tax liabilities:		
Properties and equipment, principally due to differences in depreciation and amortization	(32,814,500)	(23,842,200)
Total gross deferred tax liabilities	(32,814,500)	(23,842,200)
Net non-current deferred tax liability	$(29,843,200)	(21,800,200)

Accumulated other comprehensive loss is net of tax of $1,531,200, $750,500 and $1,092,200 as of December 31, 2004, 2003 and 2002, respectively.

In assessing the realizability of deferred tax assets, 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.

(Continued)

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.

The deferred tax asset related to AOCI increased in 2004 by $780,700 and decreased in 2003 by $341,700.

(5) Common Stock

Stock-Based Compensation Plans

As of December 31, 2004, the Company has several 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. During 2004, 23,380 shares were granted with restriction periods of four years at the market price on the date of issuance as deferred compensation and the related amount is being amortized to operations over the respective vesting period. Compensation expense for the year ended December 31, 2004 related to these shares of restricted stock was $21,100.

Options amounting to 16,880 shares were granted during 2004 to certain employees 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 summarized the activity of the Company’s option plans:

	Number of Shares	Average Exercise Price	Range of Exercise Prices
Outstanding December 31, 2001	1,230,000	$4.29	1.125 - 6.25
Exercised	(70,000)	$1.125	1.125 - 1.125
Outstanding December 31, 2002	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

(Continued)

Options outstanding under the Company's plans as of December 31, 2004:

Range of Exercise Price	Options Outstanding	Remaining Life	Options Exercisable	Weighted-Average Exercise Price
$3.75 - $6.25	60,000	3.9 years	60,000	$5.40
$37.15	16,880	10 years	-	$37.15
Total	76,880		60,000	

Common Stock Repurchase

On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. Under the program, the Board 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. This program expired on December 31, 2004. The following activity has occurred since inception of the plan on March 13, 2003 until December 31, 2004.

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

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. Such treasury stock was subsequently cancelled.

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

Stock Repurchase Agreement

The Company has stock repurchase agreements with four executive officers of the Company. The agreements require the Company to maintain life insurance on each executive in the amount of $1,000,000. The agreements provide that the Company shall utilize the proceeds from such insurance to purchase from such executives' estates or heirs, at their option, shares of the Company's stock. The purchase price for the outstanding common stock is 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.

(Continued)

(6) Employee Benefit Plans

The Company sponsors a qualified deferred compensation plan 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 $382,700, $305,500 and $288,000 for 2004, 2003 and 2002, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $300,000, $250,000 and $200,000 to the plan in cash during 2004, 2003 and 2002, respectively.

During 2003 and 2002 the Company expensed $90,000 each year under a deferred compensation arrangement with certain executive officers of the Company. These amounts were paid during 2003 to such executive officers.

The Company has a deferred compensation arrangement covering certain executive officers of the Company as a supplemental retirement benefit. During 2004, 2003 and 2002 the Company expensed $171,900, $181,900 and $171,600, respectively, and has recorded a related liability in the amount $1,000,200 and $868,300 as of December 31, 2004 and 2003, 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 during 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.

(7) Earnings Per Share

	2004	2003	2002
Basic earnings per common share:			
Net income before cumulative effect of change in accounting principle	$34,060,600	22,817,700	9,284,800
Cumulative effect of accounting change, net of tax		(198,600)	
Net income	34,060,600	22,619,100	9,284,800
Weighted average common shares outstanding	16,240,604	15,659,591	15,866,363
Basic earnings per common share	$2.10	$1.45	$0.59
Diluted earnings per common and common equivalent share:			
Net income before cumulative effect of change in Accounting principle	34,060,600	22,817,700	9,284,800
Cumulative effect of accounting change, net of tax	-	(198,600)	-
Net income applicable to common stock	34,060,600	22,619,100	9,284,800
Weighted average common shares outstanding	16,240,604	15,659,591	15,866,363
Potentially dilutive securities:			
Stock options	406,570	638,202	277,051
Weighted average common and common equivalent shares outstanding	16,647,174	16,297,793	16,143,414
Diluted earnings per common share	$2.05	$1.39	$0.58

(8) Transactions with Affiliates

Funds held for future distribution on the consolidated balance sheet of $12,911,800 and $8,410,900 primarily represents amounts owed to affiliated partnerships as of December 31, 2004 and 2003, respectively.

(Continued)

The Company provided oil and gas well drilling services and well operations services to affiliated partnerships. Substantially all of the Company's oil and gas well drilling operations, well operations and pipeline income and other income (except for $1.0 million of life insurance proceeds in 2003 discussed in Note 5) was for such partnerships. Related services of tax return preparation and other services relating to the operation of the partnerships are recorded in other income. Amounts due from the affiliated partnerships as of December 31, 2004 and 2003 were $68,100 and $929,600, and are included in notes and accounts receivable.

The Company through its wholly-owned subsidiary, PDC Securities Incorporated, acts as Dealer-Manager of the Public 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/dealers in the amounts of $9,747,600, $7,994,300 and $5,792,300 for the years ended December 31, 2004, 2003 and 2002, respectively. The net commissions and marketing allowance amounts included in other income were less than $1,000 for each of the years ending December 31, 2004, 2003 and 2002.

During 2004, 2003 and 2002, the Company paid $22,500, $30,000 and $51,800, respectively, to the Corporate Secretary's law firm for various legal services.

(9) Commitments and Contingencies

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities and industrial customers. No customer accounted for 10% or more of the Company's total revenues in 2004. One customer accounted for 10.3% and 10.8% of total revenues in 2003 and 2002, respectively.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's hedging instruments or the counterparties to the Company's gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses in 2004, 2003 or 2002.

Substantially all of the Company's drilling programs contain a repurchase provision where Investing Partners may request the Company to 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), only if such units are requested by the investors, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $6.6 million. The Company has adequate liquidity to meet this obligation. During 2004, the Company paid $408,260 under this provision for the repurchase of partnership units.

The Company's drilling programs formed since 1996 contain a performance standard which states that if certain performance levels are not met, the Company must remit a payment equal to one-half of its share of revenue from such partnership to the investing partners. During 2004, 2003, and 2002 the Company paid partnerships a total of $597,300, $385,400 and $198,500, respectively in accordance with the provision.

During the fourth quarter of 2003, the Company recorded a liability in accordance with the death benefit of the employment contract of the Company's Chief Financial Officer in the amount of $852,700.

As Managing General Partner of 10 private partnerships and 62 public partnerships the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes its and its subcontractors casualty insurance coverage is adequate to meet this potential liability.

In order to secure the services for drilling rigs, the Company makes commitments to the drilling contractor which call for penalties for a specified amount of time if the Company ceases to use such drilling rigs, an event that is not anticipated to occur. As of December 31, 2004, the Company has an outstanding commitment for $1,604,250.

(Continued)

The Company drilled one exploratory well in 2004 and plans additional exploratory wells in 2005. As of the date of this report, the exploratory well had been completed and testing was underway but the well had not been classified as successful or dry. Testing of the well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing in the second quarter of 2005. If the well is determined to be a dry hole, its costs will be expensed in the period when the determination is made as required by the successful efforts method of accounting. The cost of the well as of December 31, 2004 is $4,169,903.

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

(10) Lease Obligations

The Company has entered into certain 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, 2004 are as follows:

Year	Lease Amount
2005	$307,900
2006	209,400
2007	153,900
2008	127,200
2009	45,300
Thereafter	52,000
	$895,700

The Company's share of this lease expense for operating leases for the years ended December 31, 2004, 2003 and 2002 was $310,000, $574,700 and $660,700, respectively.

(11) Supplemental Disclosure of Cash Flows

The Company paid $1,049,200, $1,274,003 and $1,290,400 for interest in 2004, 2003 and 2002, respectively. The Company paid income taxes in 2004, 2003 and 2002 in the amounts of $5,027,800, $3,649,600 and $175,000, respectively.

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

(12) Purchases of Oil and Gas Properties

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 twenty new Niobrara wells on the property in 2004. The Company estimates that there are approximately 100 remaining increased density well locations, approximately 60 of which the Company plans to develop 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.

(Continued)

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.

(13) Derivative Financial Instruments

The futures and option contracts hedge forecasted natural gas purchases and sales, generally forecasted to occur within a three year period. The Company does not hold or issue derivatives for trading or speculative purposes. In addition, an interest rate swap agreement was used to reduce the potential impact of increases in interest rates on variable rate long-term debt.

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production and CIG-based contracts traded by JP Morgan Chase Bank, NA for Colorado production. These hedging arrangements have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the hedge relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these hedging arrangements are structured to reduce the Company's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Company might otherwise have received from price increases associated with the hedged commodity. The Company's policy prohibits the use of natural gas future and option contracts for speculative purposes.

The following tables summarize the open futures and options contracts for Riley Natural Gas and PDC as of December 31, 2004 and 2003.

Riley Natural Gas
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of December 31, 2004					
Natural Gas	Sale	3,260,000	$5.60	$18,249,250	($1,982,964)
Natural Gas	Purchase	1,130,000	$6.77	$7,644,540	($486,490)
Natural Gas	Floor	530,000	$5.30		$134,242
Natural Gas	Ceiling	265,000	$7.00		($85,541)
Contracts maturing in 12 months following December 31, 2004					
Natural Gas	Sale	2,230,000	$5.84	$13,014,810	($841,102)
Natural Gas	Purchase	860,000	$6.94	$5,965,490	($591,340)
Natural Gas	Floor	530,000	$5.30		$134,242
Natural Gas	Ceiling	265,000	$7.00		($85,541)
Prior Year Total Contracts as of December 31, 2003					
Natural Gas	Sale	2,660,000	$4.58	$12,174,130	($1,810,500)
Natural Gas	Purchase	820,000	$5.17	$4,243,420	$270,200

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

(Continued)

Petroleum Development Corporation
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of December 31, 2004					
Natural Gas	Purchase	46,776	$6.63	$310,339	($17,806)
Natural Gas	Floor	3,562,020	$4.56		$337,842
Natural Gas	Ceiling	1,556,010	$5.39		($1,526,868)
Crude Oil	Floor	166,536	$32.30		$141,880
Crude Oil	Ceiling	83,268	$40.00		($450,405)
Contracts maturing in 12 months following December 31, 2004					
Natural Gas	Sale				
Natural Gas	Purchase	46,776	$6.63	$310,339	($17,806)
Natural Gas	Floor	3,562,020	$4.56		$337,842
Natural Gas	Ceiling	1,556,010	$5.39		($1,526,868)
Crude Oil	Floor	166,536	$32.30		$141,880
Crude Oil	Ceiling	83,268	$40.00		($450,405)
Prior Year Total Contracts as of December 31, 2003					
Natural Gas	Sale	53,300	$5.40	$288,000	($40,000)
Natural Gas	Purchase	45,700	$4.77	$218,100	$30,400
Natural Gas	Floor	2,597,800	$4.29		$185,300
Natural Gas	Ceiling	691,200	$5.23		($127,800)

The maximum term over which PDC is hedging exposure to the variability of cash flows for commodity price risk is 12 months

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2004 and 2003, cash in the amount of $664,900 and $1,866,400 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. Such swap agreement expired in October 2004. At December 31, 2003, the Company was a party to an interest rate swap agreement which expired on October 11, 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 $(436,800), $(266,900) net of tax at December 31, 2003. Current market pricing models were used to estimate fair value.

By using derivative financial instruments to hedge 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.

Changes in the fair value of natural gas futures contracts designated as hedging instruments and that effectively offset the variability of cash flows associated with anticipated sales of natural gas are reported in accumulated other comprehensive income (AOCI). These amounts subsequently are reclassified into gas purchases for RNG and gas sales for PDC when the related gas is sold and affects earnings. Changes in the fair value of the interest rate swap agreement were reclassified into interest expense.

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

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

	Years Ended December 31,		
	2004	2003	2002
Property acquisition cost:			
Proved undeveloped properties	$ 4,583,000	6,167,800	1,892,700
Producing properties	720,000	33,946,600	240,000
Development costs	36,870,400	30,630,100	16,429,400
	$42,173,400	70,744,500	18,562,100

The proved reserves attributable to the development costs in the above table were 40,716,000 Mcf and 358,000 bbls for 2004, 27,719,000 Mcf and 517,000 bbls for 2003 and 19,607,000 Mcf and 130,000 bbls for 2002 (amounts unaudited). Of the above development costs incurred for the years ended December 31, 2004, 2003 and 2002 the amounts of $1,819,619, $4,289,600 and $2,699,500, 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.

(15) Oil and Gas Capitalized Costs

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,	
	2004	2003
Proved properties:		
Tangible well equipment	$157,787,800	$133,356,900
Intangible drilling costs	123,171,200	110,087,300
Undeveloped properties	9,864,300	7,576,900
Capitalized asset retirement cost	613,400	537,800
	291,436,700	251,558,900
Less accumulated depreciation, depletion and amortization	80,762,100	64,205,100
	$210,674,600	$187,353,800

(16) Results of Operations for Oil and Gas Producing Activities

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

	Years Ended December 31,		
	2004	2003	2002
Revenue:			
Oil and gas sales	$67,947,700	47,021,600	22,857,100
Expenses:			
Production costs	14,974,000	10,212,500	6,407,900
Depreciation, depletion and amortization	16,482,600	12,997,600	11,149,000
	31,456,600	23,210,100	17,556,900

Results of operations for oil and gas producing activities before provision for income taxes	36,491,100	23,811,500	5,300,200
Provision for income taxes	13,728,000	8,262,600	1,538,400
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$22,763,100	15,548,900	3,761,800

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including such costs as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and other 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 the Company's effective tax rate.

(17) Net Proved Oil and Gas Reserves (Unaudited)

The proved reserves of oil and gas of the Company have been estimated by an independent petroleum engineer, Wright & Company, Inc. at December 31, 2004, 2003 and 2002. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. 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)		
	2004	2003	2002
Proved developed and undeveloped reserves:			
Beginning of year	3,029,000	2,073,000	2,126,000
Revisions of previous estimates	305,000	533,000	124,000
Beginning of year as revised	3,334,000	2,606,000	2,250,000
New discoveries and extensions:			
Rocky Mountain Region	358,000	517,000	130,000
Dispositions to partnerships	(12,000)	(112,000)	(80,000)
Acquisitions:			
Rocky Mountain Region	17,000	307,000	-
Production	(381,000)	(289,000)	(227,000)
End of year	3,316,000	3,029,000	2,073,000
Proved developed reserves:			
Beginning of year	2,889,000	1,849,000	1,801,000
End of year	3,190,000	2,889,000	1,849,000

(Continued)

	Gas (MCF)		
	2004	2003	2002
Proved developed and undeveloped reserves:			
Beginning of year	180,998,000	128,851,000	118,608,000
Revisions of previous estimates	(10,635,000)	4,394,000	1,469,000
Beginning of year as revised	170,363,000	133,245,000	120,077,000
New discoveries and extensions:			
Rocky Mountain Region	40,716,000	27,719,000	19,607,000
Dispositions to partnerships	(4,240,000)	(4,410,000)	(4,792,000)
Acquisitions:			
Michigan Basin	96,000	265,000	4,000
Rocky Mountain Region	242,000	32,169,000	75,000
Appalachian Basin	744,000	722,000	342,000
Production	(10,372,000)	(8,712,000)	(6,462,000)
End of year	197,549,000	180,998,000	128,851,000
Proved developed reserves:			
Beginning of year	134,936,000	94,847,000	88,477,000
End of year	146,152,000	134,936,000	94,847,000

(18) 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.

	As of December 31,		
	2004	2003	2002
Future estimated revenues	$1,298,394,000	$1,088,415,000	$548,949,000
Future estimated production costs	(319,065,000)	(250,735,000)	(143,878,000)
Future estimated development costs	(95,498,000)	(65,275,000)	(50,971,000)
Future estimated income tax expense	(332,497,000)	(265,707,000)	(105,876,000)
Future net cash flows	551,334,000	506,698,000	248,224,000
10% annual discount for estimated timing of cash flows	(317,099,000)	(289,408,000)	(149,755,000)
Standardized measure of discounted future estimated net cash flows	$234,235,000	$217,290,000	$98,469,000

(Continued)

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

	Years Ended December 31,		
	2004	2003	2002
Sales of oil and gas production, net of production costs	$(52,974,000)	$(36,810,000)	$(16,449,000)
Net changes in prices and production costs	36,656,000	162,422,000	143,574,000
Extensions, discoveries and improved recovery, less related cost	135,816,000	114,533,000	39,347,000
Dispositions to partnerships	(16,782,000)	(12,936,000)	(6,940,000)
Acquisitions	6,451,000	139,078,000	1,167,000
Development costs incurred during the period	36,870,000	30,630,000	16,429,000
Revisions of previous quantity estimates	(34,611,000)	21,388,000	3,318,000
Net changes in estimated income taxes	(66,790,000)	(159,831,000)	(55,516,000)
Accretion of discount	(27,691,000)	(139,653,000)	(72,900,000)
	$16,945,000	$118,821,000	$ 52,030,000

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.

(19) Business Segments (Thousands)

PDC's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 2,700 wells from which it derives oil and gas working interests. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the years ended December 31, 2004, 2003 and 2002 is as follows:

	2004	2003	2002
REVENUES			
Drilling and Development	$119,211	71,841	57,149
Natural Gas Marketing	93,231	73,141	46,366
Oil and Gas Sales	67,948	47,022	22,857
Well Operations	8,384	7,348	6,116
Unallocated amounts (1)	1,946	3,499	2,854
Total	$290,720	202,851	135,342

(Continued)

SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and Development	$16,380	10,564	7,983
Natural Gas Marketing	1,324	689	174
Oil and Gas Sales	36,491	23,812	5,300
Well Operations	4,402	3,059	2,788
Unallocated amounts (2)			
General and Administrative expenses	(4,506)	(4,974)	(4,392)
Interest expense	(874)	(1,329)	(1,340)
Other (1)	1,386	3,103	2,569
Total	$ 54,603	34,924	13,082
SEGMENT ASSETS			
Drilling and Development	$64,348	62,546	31,279
Natural Gas Marketing	28,689	17,006	16,641
Oil and Gas Sales	221,516	204,849	145,591
Well Operations	16,518	11,602	10,706
Unallocated amounts			
Cash	112	800	1,736
Other	10,210	9,919	6,299
Total	$341,393	306,722	212,252
EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS			
Drilling and Development	$ 4,583	6,168	1,800
Natural Gas Marketing	6	-	4
Oil and Gas Sales	37,590	63,588	16,670
Well Operations	1,911	2,944	1,221
Unallocated amounts	1,302	342	82
Total	$ 45,392	73,042	19,777

(1) Includes interest on investments and partnership management fees in 2004, 2003 and 2002 and gain on sale of assets in 2004, 2003 and 2002 which are not allocated in assessing segment performance.

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

(20) Subsequent Event

In January 2005, the Company sold a portion of one of its undeveloped Garfield County, Colorado leases to another operator. The gain on such sale to be recorded in the first quarter 2005 was approximately $5.2 million, net of a $1.0 million liability recorded for a future commitment. The interest sold consisted of half the Company's leasehold interest on a "checkerboard" pattern. The Company will retain the other half of the lease. The terms of the agreement require the purchaser to drill a number of wells over a period of time on the acquired acreage. If the drilling requirements are not met part or all of the lease will revert to the Company.

(Continued)

(21) Quarterly Financial Data (Unaudited)

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

	2004				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$71,048,500	$73,923,800	$73,157,400	$72,590,100	$290,719,800
Cost of operations	56,624,200	59,315,500	58,357,200	56,439,900	230,736,800
Gross profit	14,424,300	14,608,300	14,800,200	16,150,200	59,983,000
General and administrative expenses	994,200	900,900	926,300	1,684,200	4,505,600
Interest expense	243,500	255,000	252,600	123,200	874,300
Income before income taxes	13,186,600	13,452,400	13,621,300	14,342,800	54,603,100
Income taxes	4,747,200	4,839,300	4,929,700	6,026,300[(1)]	20,542,500
Net income	$8,439,400	$ 8,613,100	$ 8,691,600	$ 8,316,500	$34,060,600
Basic earnings per share	$ .53	$ .53	$ .53	$.50	$2.10
Diluted earnings per share	$ .52	$ .52	$ .52	$.49	$2.05

(1) Includes approximately $630,000 of adjustments to the tax provision of the prior three quarters.

	2003				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$53,994,400	$42,192,500	$47,207,900	$59,456,200	$202,851,000
Cost of operations	45,125,800	33,836,200	37,648,600	45,013,400	161,624,000
Gross profit	8,868,600	8,356,300	9,559,300	14,442,800	41,227,000
General and administrative expenses	1,177,700	1,186,600	1,377,300	1,232,800	4,974,400
Interest expense	236,200	259,800	415,000	418,100	1,329,100
Income before income taxes	7,454,700	6,909,900	7,767,000	12,791,900	34,923,500
Income taxes	2,460,000	2,280,300	2,563,100	4,802,400	12,105,800
Net income before cumulative effect of change of change in accounting principle	4,994,700	4,629,600	5,203,900	7,989,500	22,817,700
Cumulative effect of change in Accounting principle (net of taxes)	(198,600)	-	-	-	(198,600)
Net income	$ 4,796,100	$ 4,629,600	$ 5,203,900	$ 7,989,500	$22,619,100
Basic earnings per share before accounting change	$ .32	$ .29	$ .33	$.52	$1.46
Cumulative effect of change in accounting principle	(.01)	.00	.00	.00	(.01)
Basic earnings per share	$ .31	$ .29	$ .33	$.52	$1.45
Diluted earnings per share before Accounting principle	$ .31	$ .29	$ .31	$.49	$1.40
Cumulative effect of change in Accounting principle	(.01)	.00	.00	.00	(.01)
Diluted earnings per share	$ .30	$ .29	$ .31	$.49	$1.39

Cost of operations include cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years Ended December 31, 2004, 2003 and 2002

Column A	Column B	Column C	Column D	Column E
Description	Balance at Beginning of Period	Additions, Charged to Costs and Expenses	Deductions	Balance At End of Period
Allowance for doubtful accounts deducted from accounts and notes receivable in the Balance sheet				
2004	$487,300	$ -	$ 78,300	$409,000
2003	$524,500	$ -	$ 37,200	$487,300
2002	$524,500	$ -	$ -	$524,500