

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC**

FORM 10/A

**GENERAL FORM FOR REGISTRATION OF SECURITIES
PURSUANT TO SECTION 12(b) OR 12(g) OF
THE SECURITIES EXCHANGE ACT OF 1934**

Rockies Region Private Limited Partnership
(Exact Name of Registrant as Specified in Its Charter)

West Virginia
(State or Other Jurisdiction of
Incorporation or Organization)

20-3890540
(IRS Employer Identification No.)

103 East Main Street, Bridgeport, West Virginia
(Address of Principal Executive Offices)

26330
(Zip Code)

Registrant's telephone number, including area code: 304-842-6256

Securities to be registered pursuant to Section 12(b) of the Act:

Title of Each Class
to be so Registered

Name of Each Exchange on Which
Each Class is to be Registered

Securities to be registered pursuant to Section 12(g) of the Act:

Limited Partnership Interests
(Title of Class)

General Partnership Interests
(Title of Class)

Form 10/A

Rockies Regional Private Limited Partnership

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INFORMATION REQUIRED IN REGISTRATION STATEMENT

Item 1. Business.

Rockies Region Private Limited Partnership (the "Partnership" or the "Registrant") was organized as a limited partnership on December 6, 2005, under the West Virginia Uniform Limited Partnership Act. Upon completion of a private placement of its securities on December 30, 2005, the Partnership was funded and commenced its business operations. The Partnership was funded with initial contributions of \$35,735,509 from 952 limited and additional general partners (collectively, the "Investor Partners") and a cash contribution of \$11,231,670 from the Managing General Partner. After payment of syndication costs of \$3,583,551 and a one-time management fee to the Managing General Partner of \$536,033, the Partnership had available cash of \$42,847,595 to commence Partnership activities.

The Partnership has drilled, owns and operates natural gas and oil wells located in Colorado and Wyoming and will produce and sell natural gas and oil from these wells. As of June 9, 2006, the Partnership has conducted the following drilling activities:

	<u>Colorado</u>	<u>Wyoming</u>	<u>Total</u>
Development wells:			
Drilled, completed and producing	41	-	41
Drilled, completed and awaiting gas pipeline connection	6	-	6
Dry hole	1	-	1
Exploratory dry hole	<u>1</u>	<u>1</u>	<u>1</u>
Total Wells Drilled	<u>48</u>	<u>1</u>	<u>49</u>

All of the wells drilled by the Partnership, except for the Wyoming exploratory well, were development-type wells drilled in Colorado and produce predominantly natural gas along with associated crude oil. The forty-nine wells in the table above are the only wells to be drilled by the Partnership because all of the funds raised in the Partnership offering will have been utilized once the well completion work and pipeline connections on the six non-producing wells are finished. The Wyoming exploratory well has been fractured in multiple zones but was determined to be a dry hole.

The Colorado wells were drilled in the Wattenberg Field and the Grand Valley Field. Thirty-eight wells were drilled in the Wattenberg Field to the Codell formation or deeper, and the remainder of the Colorado wells were in the Grand Valley Field. The wells drilled in the Grand Valley Field (the Piceance Basin) take longer to drill and are typically more difficult to complete; consequently, the costs of these wells are considerably greater as compared to the Wattenberg wells.

A development well is a well that is drilled close to and into the same formation as wells which have already produced and sold oil or natural gas. An exploratory well is one which is drilled in an area where there has been no oil or natural gas production, or a well which is drilled to a previously untested or non-producing zone in an area where there are wells producing from other formations.

The address and telephone number of the Partnership and Petroleum Development Corporation ("PDC"), the Managing General Partner of the Partnership, are 103 East Main Street, P.O. Box 26, Bridgeport, West Virginia 26330 and (304) 842-6256.

Drilling Activities

The Partnership has obtained all requisite permits necessary for it to conduct its drilling and production activities. The Partnership has invested in the drilling of forty-nine prospects on which it has drilled an equal number of wells. The Partnership's working interests in these wells is 100%, except for a working interest of 70% in the Wyoming exploratory well. As indicated by the table above, forty-one wells are currently producing and six other wells are in various stages of completion or having pipeline facilities installed for connection. The Partnership did not acquire any interest in currently or formerly producing natural gas and oil wells. All forty-eight development wells

drilled by the Partnership are adjacent to, or located nearby, producing wells and drilled to the same formation(s) as the producing wells and targeted proved or probable reserves and none of the development wells proved up any additional acreage outside of the spacing unit. For this reason, the Partnership will be assigned only the leasehold acreage for the spacing units on the forty-eight development wells and the one exploratory well, as determined by state rules and regulations in conjunction with local practice. The spacing unit for Colorado wells encompasses approximately 32 acres for wells drilled in the Wattenberg Field of the Denver-Julesburg (DJ) Basin and approximately 10 to 20 acres for wells drilled in the Grand Valley Field of the Piceance Basin. The exploratory well drilled by the Partnership in Wyoming, was determined to be a dry hole.

Thirty-eight of the Partnership wells were drilled to target the Codell formation, or deeper, in the Wattenberg Field, of which thirty-seven wells have been successfully completed, 32 of which are in production and the remaining five are expected to be connected and producing by the end of third quarter 2006. PDC plans to recomplete most of the Codell formations in the Wattenberg Field wells after they have been in production for five years or more, although the exact timing may be delayed or accelerated due to changing commodity prices. A recompletion consists of a second fracture treatment of the formation similar to the fracture treatment used when the well is first completed. The cost of a recompletion is about one third of the cost of a new well (currently about \$185,000 for the recompletion). PDC will charge the Partnership for the direct costs of recompletions, and will pay its proportionate share of costs based on the operating costs sharing ratios of the Partnership. PDC and other producers have found that the recompletions typically increase the production rate and recoverable reserves of the wells significantly. PDC has recompleted over 180 Codell wells to date and substantially all of those wells have experienced significant production increases.

The Partnership may borrow the funds necessary to pay for the recompletions, and payment for those borrowings will be made from the Partnership production proceeds. Any such borrowings will be non-recourse to the Investor Partners in the Partnership.

PDC's experience to date with Codell recompletions has generally been very good, although not all recompletions have been successful. If the Partnership participates in unsuccessful recompletions, it may have additional costs without having sufficient incremental revenue to pay those costs, which would reduce the funds available for distribution to the Investor Partners and PDC.

Title to Properties

PDC holds record title in its name to leases, spacing units or portions of leases/units as described above. PDC will assign its interest in the lease to the Partnership. Leases acquired by the Partnership will initially and temporarily be held in PDC's name, as nominee, to facilitate joint-owner operations and the acquisition of properties. Unrecorded assignments from PDC, the current record owner, will indicate that the leases are being held for the benefit of the Partnership and that the leases are not subject to debts, obligations or liabilities of the record owner; however, unrecorded assignments may not fully protect the Partnership from the claims of PDC's creditors.

Partnership investors must rely on PDC to use its best judgment to obtain appropriate title to leases. Provisions of the limited partnership agreement relieve PDC from any error in judgment with respect to the waiver of title defects. PDC will take those steps as it deems necessary to assure that title to the leases is acceptable for purposes of the Partnership. PDC will use its own judgment in waiving title requirements and will not be liable for any failure of title to leases transferred to the Partnership. Further, PDC does not warrant the validity or merchantability of titles to any leases to be acquired by the Partnership. PDC is accountable to the Partnership as a fiduciary and consequently must exercise its good faith and integrity in handling Partnership affairs. Moreover, PDC must act at all times in the best interests of the Partnership and the Investor Partners.

Partnership Prospects

The Partnership's forty-eight development wells are located in Colorado and the one exploratory well is located in Wyoming. Of the development wells, thirty-eight wells are located in the Wattenberg Field (DJ Basin) and ten are located in the Grand Valley Field (Piceance Basin). One of the wells drilled in the Wattenberg Field and the exploratory well drilled in Wyoming were determined to be dry holes. The details of these prospect areas are further outlined below.

Colorado. The Wattenberg Field, located north and east of Denver, Colorado, is in the Denver-Julesburg (DJ) Basin. The typical well production profile has an initial high production rate and relatively rapid decline, followed by years of relatively shallow decline. Natural gas is the primary hydrocarbon produced; however, many wells will also produce oil. The purchase price for the gas may include revenue from the recovery of propane and butane in the gas stream, as well as a premium for the typical high-energy content of the gas. Wells in the area may include as many as four productive formations. From shallowest to deepest, these formations are the Sussex, the Niobrara, the Codell and the J Sand. The primary producing zone in most wells will be the Codell sand which produces a combination of natural gas and oil.

The Piceance Basin, located near the western border of Colorado, is the second Colorado prospect area. It is expected that the Piceance Basin wells will produce natural gas along with small quantities of oil and water. The producing interval consists of a total of 150 to 300 feet of productive sandstone divided in 10 to 15 different zones. The production zones are separated by layers of nonproductive shale resulting in a total interval of 2,000 to 4,000 feet with alternating producing and non-producing zones. The gas reserves and production are divided into these numerous smaller zones.

Wyoming. The Red Desert Basin, located in southwestern Wyoming, is the third prospect area. Successful wells drilled in this area are expected to produce primarily natural gas with small associated amounts of oil. The deepest potential targets are part of the Mesaverde formation and the Lewis, Fox Hills and Lance formations. In addition, shallower Tertiary aged Fort Union and Wasatch Sands may be secondary targets. Well depths may range from approximately 8,000 to 12,000 feet or more depending upon structural position within the basin. It is anticipated that several stacked sandstone sequences may be productive in a single well. The single well drilled by the Partnership in Wyoming was to a depth of 12,525 feet and was determined to be a dry hole. The accumulated cost of this well as of March 31, 2006, was \$1,251,337.

Well Operations

PDC is contracted to serve as operator of all of the Partnership's wells. PDC, as operator, will represent the Partnership in all operations matters, including the drilling, testing, completion and equipping of wells and the sale of the Partnership's oil and gas production from wells of which it is the operator.

PDC will, in some cases, provide equipment and supplies, and will perform salt water disposal services and other services for the Partnership. PDC may sell equipment to the Partnership as needed in the drilling or completion of Partnership wells. All equipment and services will be sold at the lesser of cost or competitive prices in the area of operations.

Gas Pipeline and Transmission. PDC has drilled all of the Partnership's wells in Colorado and Wyoming in the vicinity of transmission pipelines and gathering systems. PDC believes there are sufficient transmission pipelines and gathering systems for the Partnership's natural gas production. The cost, timing and availability of gathering pipeline connections and service varies from area to area, well to well, and over time. In selecting prospects for the Partnership, PDC included in its evaluation the anticipated cost, timing and expected reliability of gathering connections and capacity. When a significant amount of development work is being done in an area, production can temporarily exceed the available markets and pipeline capacity to move gas to more distant markets. This can lead to lower natural gas prices relative to other areas as the producers compete for the available markets by reducing prices. It can also lead to curtailments of production and periods when wells are shut-in due to lack of market.

Sale of Production. The Partnership will sell the oil and natural gas produced from its prospects on a competitive basis at the best available terms and prices. PDC intends to utilize the services of its wholly-owned subsidiary Riley Natural Gas (RNG) in marketing the gas produced from Partnership wells. PDC will not make any commitment of future production that does not primarily benefit the Partnership. Generally, purchase contracts for the sale of oil are cancelable on 30 days notice, whereas purchase contracts for the sale of natural gas may range from spot market sales of short duration to contracts with a term of a number of years that may require the dedication of the gas from a well for a period ranging up to the life of the well.

The Partnership will sell natural gas discovered by it at negotiated prices based upon a number of factors, including the quality of the gas, well pressure, estimated reserves, prevailing supply conditions and any applicable price regulations promulgated by the Federal Energy Regulatory Commission (FERC). The Partnership expects to sell oil produced by it to local oil purchasers at spot prices. The produced oil is stored in tanks at or near the location of the Partnership's wells for routine pickup by oil transport trucks.

Price Hedging. Natural gas and oil spot market prices have been extremely volatile in the past, and the volatility may continue in the future. In order to provide a more predictable cash flow stream from Partnership wells, PDC may use financial hedges, put options, call options, and other derivative instruments to offset variations in prices. These hedges may result in more predictable cash flow than would otherwise have been received and at times result in higher cash flow, but at other times in lower cash flow.

Drilling and Operating Agreement. The Partnership has entered into a drilling and operating agreement with PDC. The drilling and operating agreement provides that the operator will conduct and direct drilling operations and have full control of all operations on the Partnership's prospects. The operator will have no liability to the Partnership for losses sustained or liabilities incurred, except as may result from the operator's negligence or misconduct. Under the terms of the drilling and operating agreement, PDC may subcontract responsibilities as operator for Partnership wells. PDC will retain responsibility for work performed by subcontractors.

To the extent the Partnership's wells have less than a 100% working interest, the Partnership will pay only a proportionate share of total lease, development, and operating costs, and will receive a proportionate share of production subject only to royalties and overriding royalties. The Partnership is responsible only for its obligations and is liable only for its proportionate working interest share of the costs of developing and operating the wells.

The operator provides all necessary labor, vehicles, supervision, management, accounting, and overhead services for normal production operations, and deducts from Partnership revenues a monthly charge for these services. The charge for these operations and field supervision fees (referred to as "well tending fees") for each producing well will be based on competitive industry rates, which vary based upon the area of operation. The monthly administrative charge is \$100 per well for Partnership accounting, engineering, management, and general and administrative expenses. Charges for areas with current operations are shown below.

Initial Per Well Operating Charges

Well Location	Monthly Per Well Partnership Administration Fee	Monthly Per Well Tending Fee
Wattenberg Field (Denver-Julesburg Basin)	\$100	\$400
Piceance Basin	\$100	\$700
Red Desert Basin	\$100	\$950

The well tending fees and administration fees may be adjusted annually beginning January 1, 2007, to an amount equal to the rates initially established by the drilling and operating agreement, multiplied by the average of the then current Oil and Gas Extraction Index and the Professional and Technical Services Index, as published by the United States Department of Labor, Bureau of Labor Statistics, provided that the charge may not exceed the rate which would be charged by the comparable operators in the area of operations. This average is commonly referred to as the Accounting Procedure Wage Index Adjustment which is published annually by the Council of Petroleum Accountants Societies.

The Partnership has the right to take in kind and separately dispose of its share of all oil and gas produced from its prospects, excluding its proportionate share of production required for lease operations and production unavoidably lost. Initially, the Partnership designated the operator as its agent to market its production and authorized the operator to enter into and bind the Partnership in those agreements it deems in the best interest of the Partnership for the sale of its oil and/or gas. If pipelines owned by PDC are used in the delivery of natural gas to market, PDC may charge a gathering fee not to exceed that which would be charged by a non-affiliated third party for a similar service.

The drilling and operating agreement continues in force as long as any well or wells produce, or are capable of production, and for an additional period of 180 days from cessation of all production, or until PDC is replaced as Managing General Partner as provided for in the Agreement.

Production Phase of Operations

General. When Partnership wells are "complete" (i.e., drilled, fractured or stimulated, and all surface production equipment and pipeline facilities necessary to produce the well are installed), production operations commence on each well.

The Partnership sells the produced natural gas to industrial users, gas marketers, including affiliated marketers, commercial end users, interstate or intrastate pipelines or local utilities, primarily under market sensitive contracts in which the price of gas sold varies as a result of market forces. Some leases, and thus the natural gas derived from wells drilled on those leases, may be dedicated to particular markets at the time the Partnership acquired those leases, or subsequent to, as part of the gas marketing arrangements.

PDC, on behalf of the Partnership, may enter into fixed price contracts, or utilize derivatives, including hedges, swaps or options in order to offset some or all of the price variability for particular periods of time, generally for less than two years. The use of derivatives may entail fees, including the time value of money for margin requirements, which are charged to the Partnership.

PDC utilizes RNG to market the Partnership's produced natural gas, enter into hedges or swaps, collars or purchase options on behalf of the Partnership. RNG is entitled to charge reasonable fees for its services, including out-of-pocket costs. These fees will be equal to or less than fees charged to non-affiliated producers for similar services.

Seasonal factors, such as effects of weather on prices received and costs incurred may impact the Partnership's results. In addition, both sales volumes and prices tend to be affected by demand factors with a significant seasonal component.

Revenues, Expenses and Distributions

The Partnership's share of production revenue from a given well will be burdened by and/or subject to royalties and overriding royalties, monthly operating charges, taxes and other operating costs.

The above items of expenditure involve amounts payable solely out of, and expenses incurred solely by reason of, production operations. Although the Partnership is permitted to borrow funds for its operations, it is PDC's practice to deduct operating expenses from the production revenue for the corresponding period, and to defer the collection of operating expenses to future periods when revenues are insufficient to render full payment.

Interests of Parties in Production Revenues

PDC, the Investor Partners, and unaffiliated third parties (including landowners) share revenues from production of natural gas and oil from wells in which the Partnership has an interest. The following chart illustrates the interest of gross revenues derived from the wells. For the purpose of this chart, "gross revenue" is defined as the "wellhead gas and oil revenue" paid by the purchasers. Landowner and other royalties payable to unaffiliated third parties may vary, generally between 12.5% and 25% or more; however, the average of the royalty interests for all prospects or wells of the Partnership may not exceed 25%.

Illustration of Partnership Revenue Sharing			
Entity or Interest Owners	Partnership Interests	Gross Revenue Interests (Partnership Revenues and Third Party Royalties)	
		<i>If 12½% Royalty:</i>	<i>If 25% Royalty:</i>
PDC, the Managing General Partner	30%	26.25%	22.50%
Investor Partners	70%	61.25%	52.50%
Landowners and Over-riding Royalty Owners	N/A	12.50%	25.00%
Totals	100%	100.00%	100.00%

Insurance

PDC, in its capacity as operator, carries well pollution liability, public liability and worker's compensation insurance, but that insurance may not be sufficient to cover all liabilities. Each unit held by the additional general partners represents an open-ended security for unforeseen events such as blowouts, lost circulation, and stuck drill pipe, which may result in unanticipated additional liability materially in excess of the per unit subscription amount.

PDC has obtained various insurance policies, as described below, and intends to maintain these policies subject to PDC's analysis of their premium costs, coverage and other factors. PDC may, in its sole discretion, increase or decrease the policy limits and types of insurance from time to time as deemed appropriate under the circumstances, which may vary materially. PDC is the beneficiary under each policy and pays the premiums for each policy, except the Managing General Partner and the Partnership are co-insured and co-beneficiaries with respect to the insurance coverage referred to in #2 and #5 below. Additionally, PDC as operator of the Partnership's wells requires all of PDC's subcontractors to carry liability insurance coverage with respect to their activities. In the event of a loss, the insurance policies of the particular subcontractor at risk would be drawn upon before the insurance of the Managing General Partner or that of the Partnership. PDC has obtained and expects to maintain the following insurance.

1. Worker's compensation insurance in full compliance with the laws for the states of Colorado and Wyoming; this insurance will be obtained for any other jurisdictions where the Partnership conducts its business;
2. Operator's bodily injury liability and property damage liability insurance, each with a limit of \$1,000,000;
3. Employer's liability insurance with a limit of not less than \$1,000,000;
4. Automobile public liability insurance with a limit of not less than \$1,000,000 per occurrence, covering all automobile equipment; and

5. Operator's umbrella liability insurance with a limit of \$80,000,000 for each well location and in the aggregate.

PDC has determined that adequate insurance has been provided to the Partnership with coverage sufficient to protect the Investor Partners against the foreseeable risks of drilling. PDC has maintained liability insurance, including umbrella liability insurance, of at least two times the Investing Partners subscriptions, but in no event less than \$10 million during drilling operations. PDC maintained the two times insurance coverage during its drilling activities up to a maximum coverage of \$80 million.

Competition and Markets

Competition is keen among persons and companies involved in the exploration for and production of oil and natural gas. The Partnership will compete with entities having financial resources and staffs substantially larger than those available to the Partnership. There are thousands of oil and natural gas companies in the United States. The national supply of natural gas is widely diversified. As a result of this competition and FERC and Congressional deregulation of natural gas and oil prices, prices are generally determined by competitive forces.

The marketing of any oil and natural gas produced by the Partnership will be affected by a number of factors which are beyond the Partnership's control and whose exact effect cannot be accurately predicted. These factors include the volume and prices of crude oil imports, the availability and cost of adequate pipeline and other transportation facilities, the marketing of competitive fuels, such as coal and nuclear energy, and other matters affecting the availability of a ready market, such as fluctuating supply and demand. Among other factors, the supply and demand balance of crude oil and natural gas in world markets has caused significant variations in the prices of these products over recent years.

FERC Order No. 636, issued in 1992, restructured the natural gas industry by requiring pipelines to separate their storage, sales and transportation functions and establishing an industry-wide structure for "open-access" transportation service. Order No. 637, issued in February 2000, further enhanced competitive initiatives, by removing price caps on short-term capacity release transactions.

FERC Order No. 637 also enacted other regulatory policies that increase the flexibility of interstate gas transportation, maximize shippers' supply alternatives, and encourage domestic natural gas production in order to meet projected increases in natural gas demand. These increases in demand will come from a number of sources, including as boiler fuel to meet increase electric power generation needs and as an industrial fuel that is environmentally preferable to alternatives such as nuclear power and coal. This trend has been evident over the past year, particularly in the western U.S., where natural gas is the preferred fuel for environmental reasons, and electric power demand has directly affected demand for natural gas.

The combined impact of FERC Order 636 and 637 has been to increase the competition among gas suppliers from different regions.

In 1995, the North American Free Trade Agreement ("NAFTA") eliminated trade and investment barriers in the United States, Canada, and Mexico, increasing foreign competition for natural gas production. Legislation that Congress may consider with respect to oil and natural gas may increase or decrease the demand for the Partnership's production in the future, depending on whether the legislation is directed toward decreasing demand or increasing supply.

Members of the Organization of Petroleum Exporting Countries (OPEC) establish prices and production quotas for petroleum products from time to time, with the intent of reducing the current global oversupply and maintaining or increasing price levels. PDC is unable to predict what effect, if any, future OPEC actions will have on the quantity of, or prices received for, oil and natural gas produced and sold from the Partnership's wells.

Various parts of the prospect area are crossed by pipelines belonging to Colorado Interstate Gas, Encana, Duke, Williams and others. These companies have all traditionally purchased substantial portions of their supply from Colorado producers. Transportation on these systems requires that delivered natural gas meet quality standards and that a tariff be paid for quantities transported.

The Partnership expects to sell natural gas from its wells to Duke Energy, Encana and Williams on the spot market via open access transportation arrangements through Colorado Interstate Gas, Williams or other pipelines. As a result of FERC regulations that require interstate gas pipelines to separate their merchant activities from their transportation activities and require them to release available capacity on both a short and a long-term basis, local distribution companies must take an increasingly active role in acquiring their own gas supplies. Consequently, pipelines and local distribution companies are buying natural gas directly from natural gas producers and marketers, and retail unbundling efforts are causing many end-users to buy their own reserves. Activity by state regulatory commissions to review local distribution company procurement practices more carefully and to unbundle retail sales from transportation has caused gas purchasers to minimize their risks in acquiring and attaching gas supply and has added to competition in the natural gas marketplace.

In FERC Order No. 587 and other initiatives, pipelines were required to develop electronic communications in order to ensure that the gas industry is more competitive. Pipelines must provide standardized access via the Internet to information concerning capacity and prices, and standardized procedures are now available for nominating and scheduling deliveries. The industry has also developed methods to access and integrate all gas supply and transportation information on a nationwide basis, via the Internet, so as to create a national market. Furthermore, parallel developments toward an electronic marketplace for electric power, mandated by the FERC in Order Nos. 888 and 2000, are serving to create multi-national markets for energy products generally. These systems will allow rapid consummation of natural gas transactions. Natural gas purchased in West Virginia, could, for example, be used in Seattle. Although this system may initially lower prices due to increased competition, it is anticipated to expand natural gas markets and to improve the reliability of the markets.

Natural Gas and Crude Oil Pricing

PDC anticipates selling the natural gas and oil from Partnership wells in Colorado and Wyoming subject to market sensitive contracts, the price of which will increase or decrease with market forces beyond control of the Partnership. Historically, PDC has sold the natural gas in the Piceance Basin primarily to Williams Production RMT, which has an extensive gathering and transportation system in the field. In the Wattenberg Field, the natural gas is sold primarily to Duke Energy Field Services, which gathers and processes the gas and liquefiable hydrocarbons produced. Gas produced in Colorado is subject to changes in market prices on a national level, as well as changes in the market within the Rocky Mountain Region. Sales may be affected for short periods of time by capacity interruptions on pipelines transporting gas out of the region.

Sales of natural gas by the Partnership will be subject to regulation by governmental regulatory agencies. Generally, the regulatory agency in the state where a producing gas well is located supervises production activities and the transportation of gas sold into intrastate markets. FERC regulates the rates for interstate transportation of natural gas but, under the Wellhead Decontrol Act of 1989, FERC may not regulate the price of natural gas. Deregulated natural gas production may be sold at market prices determined by supply, demand, Btu content, pressure, location of wells, and other factors.

Currently, PDC sells its crude oil primarily to Teppco Crude Oil, L.P. Through affiliates, Teppco owns and operates one of the largest common carrier pipelines of refined petroleum products and liquefied petroleum gases in the United States; owns and operates petrochemical and natural gas liquid pipelines; is engaged in crude oil transportation, storage, gathering and marketing; and owns and operates natural gas gathering systems. Generally, the oil is picked up at the well site and trucked to either refineries or oil pipeline interconnects for redelivery to refineries. Oil prices will fluctuate not only with the general market for oil as may be indicated by changes in the New York Mercantile Exchange, but also due to changes in the supply and demand at the various refineries. Additionally, the cost of trucking or transporting the oil to market will affect the price the Partnership will ultimately receive for the oil.

Governmental Regulation

Federal and state regulations will affect production of Partnership oil and natural gas. In most areas of operations, the production of oil is regulated by conservation laws and regulations, which control the conduct of oil and gas operations.

The Partnership's drilling and production operations are subject to environmental protection regulations established by federal, state, and local agencies, which in turn may necessitate significant capital outlays which would materially affect the financial position and business operations of the Partnership. Environmental laws and regulations that have a material impact on the oil and natural gas industry include the federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and their state counterparts. These laws and regulations may require acquisition of permits before drilling commences and may restrict the types, quantities and concentrations of various substances that can be released into the environment. These laws and regulations are the primary vehicles for imposition of such requirements and for civil, criminal and administrative penalties and other sanctions for violation of their requirements. In addition, the federal Comprehensive Environmental Response Compensation and Liability Act and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release of hazardous substances into the environment. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of remedial action as well as damages to natural resources.

The Partnership's operations are subject to various types of regulations at the federal, state and local levels. The interstate transportation and sale of natural gas are subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation.

The various states regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future.

Although the regulatory burden on the oil and natural gas industry increases the Partnership's cost of doing business and, consequently, affects the Partnership's profitability, these burdens generally do not affect the Partnership any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of productions. The Partnership believes it is in compliance with applicable federal, state and local rules and regulations, including environmental laws and regulations.

Proposed Regulation

Various legislative proposals in Congress and in state legislatures could, if enacted, affect the petroleum and natural gas industries. These proposals involve, among other things, imposition of direct or indirect price limitations on natural gas production, expansion of drilling opportunities in areas that would compete with Partnership production, imposition of land use controls (such as prohibiting drilling activities on federal and state lands in roadless wilderness areas), landowners' "rights" legislation, alternative fuel use requirements and/or tax incentives and other measures. At the present time, it is impossible to predict what proposals, if any, will actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals will have on the Partnership's operations.

Item 1A. Risk Factors.

In the course of its normal business, the Partnership is subject to a number of risks that could adversely impact its business, operating results, financial condition, and cash distributions. You should carefully consider the following risk factors in addition to the other information included in the report.

Drilling natural gas and oil wells is speculative and may be unprofitable and result in the total loss of investment.

The drilling and completion operations undertaken by the Partnership for the development of natural gas and oil reserves are inherently speculative and involve a high degree of risk and the possibility of a total loss of investment. PDC cannot predict whether any prospect will produce commercial quantities of natural gas or oil. Drilling activities may result in unprofitable well operations, not only from non-productive wells, but also from wells that do not produce natural gas or oil in sufficient quantities or quality to return a profit on the amounts expended. PDC cannot predict the life and the ultimate production of any wells, and the actual lives could differ from those anticipated. Consequently, Partnership wells may not produce sufficient natural gas and oil for investors to receive a profit or even to recover their initial investment.

The partnership units are not registered, there will be no public market for the units, and as a result an Investor Partner may not be able to sell his or her units.

There is and will be no public market for the units nor will a public market develop for the units. Investor Partners may not be able to sell their Partnership interests or may be able to sell them only for less than fair market value. The offer and sale of units have not been, and will not in the future be, registered under the Securities Act or under any state securities laws. Each purchaser of units has been required to represent that such investor has purchased the units for his or her own account for investment and not with a view to resale or distribution. No transfer of a unit may be made unless the transferee is an "accredited investor" and such transfer is registered under the Securities Act and applicable state securities laws, or an exemption therefrom is available. The Partnership may require that the transferor provide an opinion of legal counsel stating that the transfer complies with all applicable securities laws. A sale or transfer of units by an investor requires PDC's prior written consent. For these and other reasons, an investor must anticipate that he or she will have to hold his or her Partnership interests indefinitely and will not be able to liquidate his or her investment in the Partnership. Consequently, an investor must be able to bear the economic risk of investing in the Partnership for an indefinite period of time.

The additional general partners will be individually liable for Partnership obligations and liabilities that arose prior to conversion to limited partners (which can occur only after the drilling completion operations are finished) that are beyond the amount of their subscriptions, Partnership assets, and the assets of the Managing General Partner.

Under West Virginia law, the state in which the Partnership has organized, general partners of a limited partnership have unlimited liability with respect to the Partnership. Therefore, the additional general partners of the Partnership will be liable individually and as a group for all obligations and liabilities of creditors and claimants, whether arising out of contract or tort, in the conduct of the Partnership's operations until such time as the additional general partners are converted to limited partners. Under the Partnership Agreement, this conversion is not scheduled to occur until the drilling and completion operations are finished. Irrespective of conversion, the additional general partners will remain fully liable for obligations and liabilities that arose prior to conversion. Investors as additional general partners may be liable for amounts in excess of their subscriptions, the assets of the Partnership, including insurance coverage, and the assets of the Managing General Partner.

The Partnership may retain Partnership revenues or borrow funds if needed for Partnership operations to fully develop the Partnership's wells; if full development of the Partnership's wells proves commercially unsuccessful, an investor might anticipate a reduction in cash distributions.

The Partnership intends to utilize substantially all available capital raised in the offering for the drilling and completion of wells and will have only nominal funds available for Partnership purposes prior to the time there is production from Partnership well operations. In the future, PDC may wish to rework or recomplete Partnership wells

but PDC has not held money from the initial investment for that future work. The future development of the Partnership's wells might not prove commercially successful and the further-developed Partnership wells might not generate sufficient funds from production to increase distributions to the investors to cover revenues retained or to repay financial obligations of the Partnership for borrowed funds plus interest. If future development of the Partnership's wells is not commercially successful, whether using funds retained from production revenues or borrowed funds, these operations could result in a reduction of cash distributions to the Investor Partners of the Partnership.

Increases in prices of oil and natural gas have increased the cost of drilling and development and may affect the performance of the Partnership in both the short and long term.

In the current high price environment, most oil and gas companies have increased their expenditures for drilling new wells. This has resulted in increased demand and higher cost for leases, oilfield services and well equipment. Because of these higher costs, the risk to the Partnership of decreased profitability from future decreases in oil and natural gas prices is increased.

Reductions in prices of oil and natural gas reduce the profitability of the Partnership's production operations.

Global economic conditions, political conditions, and energy conservation have created unstable prices. Revenues of the Partnership are directly related to natural gas and oil prices. The prices for domestic natural gas and oil production have varied substantially over time and by location and are likely to remain extremely unstable. Revenue from the sale of oil and natural gas increases when prices for these commodities increase and declines when prices decrease. These price changes can occur rapidly and are not predictable and are not within the control of the Partnership. A decline in natural gas and/or oil prices would result in lower revenues for the Partnership and a reduction of cash distributions to the partners of the Partnership.

The high level of drilling activity could result in an oversupply of natural gas on a regional or national level, resulting in much lower commodity prices.

Recently, the natural gas market has been characterized by excess demand compared to the supplies available, leading in general to higher prices for natural gas. The high level of drilling, combined with a reduction in demand resulting from higher prices, could result in an oversupply of natural gas. In the Rocky Mountain region, rapid growth of production and increasing supplies may result in lower prices and production curtailment due to limitations on available pipeline facilities or markets not developed to utilize or transport the new supplies. In both cases, the result would probably be lower prices for the natural gas the Partnership produces, reduced profitability for the Partnership and reduced cash distributions to the Investor Partners.

Sufficient insurance coverage may not be available for the Partnership, thereby increasing the risk of loss for the Investor Partners.

It is possible that some or all of the insurance coverage which the Partnership has available may become unavailable or prohibitively expensive. In that case, PDC might elect to change the insurance coverage. The additional general partners could be exposed to additional financial risk due to the reduced insurance coverage and due to the fact that additional general partners would continue to be individually liable for obligations and liabilities of the Partnership. Investor Partners could be subject to greater risk of loss of their investment because less insurance would be available to protect the Partnership from casualty losses. Moreover, should the Partnership's cost of insurance become more expensive the amount of cash distributions to the investors will be reduced.

Through their involvement in Partnership and other non-partnership activities, the Managing General Partner and its affiliates have interests which conflict with those of the Investor Partners; actions taken by the Managing General Partner in furtherance of its own interests could result in the Partnership's being less profitable and a reduction in cash distributions to the investors.

PDC's continued active participation in oil and natural gas activities for its own account and on behalf of other partnerships organized or to be organized by PDC and the manner in which Partnership revenues are allocated

create conflicts of interest with the Partnership. PDC has interests which inherently conflict with the interests of the Investor Partners. In operating the Partnership, the Managing General Partner and its affiliates could take actions which benefit themselves and which do not benefit the Partnership. These actions could result in the Partnership's being less profitable. In that event, an Investor Partner could anticipate a reduction of cash distributions.

The Partnership and other partnerships sponsored by the Managing General Partner may compete with each other for prospects, equipment, contractors, and personnel; as a result, the Partnership may find it more difficult to operate effectively and profitably.

Including the Partnership, PDC acts as the managing general partner for a total of 75 limited partnerships. During and after 2006, PDC plans to offer interests in other partnerships to be formed for substantially the same purposes as those of the Partnership. Therefore, a number of partnerships with unexpended capital funds, including those partnerships formed before and after the Partnership, may exist at the same time. The Partnership may compete for equipment, contractors, and PDC personnel (when the Partnership is also needful of equipment, contractors and PDC personnel), which may make it more difficult and more costly to obtain services for the Partnership. In that event, it is possible that the Partnership would be less profitable. Additionally, because PDC must divide its attention in the management of its own affairs as well as the affairs of the 74 limited partnerships PDC has organized in previous programs, the Partnership will not receive PDC's full attention and efforts at all times.

The Partnership's derivative activities could result in reduced revenue compared to the level the Partnership might experience if no derivative instruments were in place.

The Partnership expects to use derivative instruments to reduce the impact of price movements on revenue. While these derivative instruments protect the Partnership against the impact of declining prices, they also may limit the positive impact of price increases. As a result, the Partnership may have lower revenues when prices are increasing than might otherwise be the case, and may also reduce the Partnership's cash flows and cash distributions to the Investor Partners.

Hedging transactions have in the past and may in the future impact our cash flow from operations. Our commodity hedging may prevent us from benefiting fully from price increases and may expose us to other risks.

PDC will enter into hedging arrangements to reduce the Partnership's exposure to fluctuations in natural gas and crude oil prices and to achieve more predictable cash flow. Although the Partnership's hedging activities may limit the Partnership's exposure to declines in natural gas and crude oil prices, these activities may also limit and have in the past limited, additional revenues from increases in natural gas and crude oil prices. To the extent that the Partnership engages in hedging activities to protect itself from commodity price volatility, the Partnership may be prevented from realizing the benefits of price increases above the levels of the hedges.

Additionally, the hedging transactions PDC has entered into, or will enter into, may not adequately protect the Partnership from financial loss due to circumstances such as:

- Highly volatile natural gas and crude oil prices;
- Production being less than expected; or
- A counterparty defaults on its contractual obligations.

A significant financial loss by the Managing General Partner could result in PDC's inability to indemnify additional general partners for personal losses suffered because of Partnership liabilities.

As a result of PDC's commitments as managing general partner of several partnerships and because of the unlimited liability of a general partner to third parties, PDC's net worth is at risk of reduction if PDC suffers a significant financial loss. Because PDC is primarily responsible for the conduct of the Partnership's affairs, as well as the affairs of other partnerships for which PDC serves as managing general partner, a significant adverse financial reversal for PDC could result in PDC's inability to pay for Partnership liabilities and obligations. The additional

general partners of the Partnership might be personally liable for payments of the Partnership's liabilities and obligations. Therefore, the Managing General Partner's financial incapacity could increase the risk of personal liability as an additional general partner because PDC would be unable to indemnify the additional general partners for any personal losses they suffered arising from Partnership operations.

Fluctuating market conditions may cause a decline in the profitability of the Partnership.

The sale of any natural gas and oil produced by the Partnership will be affected by fluctuating market conditions. From time-to-time, a surplus of natural gas or oil may occur in areas of the United States. The effect of a surplus may be to reduce the price the Partnership receives for the natural gas or oil production, or to reduce the amount of natural gas or oil that the Partnership may produce and sell. As a result, the Partnership may not be profitable. Lower prices and/or lower production and sales will result in lower revenues for the Partnership and a reduction in cash distributions to the partners of the Partnership.

The Partnership 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 Partnership's 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 Partnership 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 the Partnership's operations and subject the Partnership 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.

The Partnership's activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas we may produce and sell. 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 or 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 our ability to develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our ability to pay distributions to our unitholders. We further reference sections "Government Regulation" and "Proposed Regulation" in Item 1, Business, for a detailed discussion of the laws and regulations that affect the Partnership's activities.

Environmental hazards involved in drilling natural gas and oil wells may result in substantial liabilities for the Partnership.

There are numerous natural hazards involved in the drilling of wells, including unexpected or unusual formations, pressures, blowouts involving possible damages to property and third parties, surface damages, personal injury or loss of life, damage to and loss of equipment, reservoir damage and loss of reserves. Uninsured liabilities would reduce the funds available to the Partnership, may result in the loss of Partnership properties and may create liability for additional general partners. The Partnership may become subject to liability for pollution, abuses of the environment and other similar damages, and it is possible that insurance coverage may be insufficient to protect the Partnership against all potential losses. In that event, Partnership assets would be used to pay personal injury and property damage claims and the costs of controlling blowouts or replacing destroyed equipment rather than for drilling activities. These payments would cause an otherwise profitable partnership to be less profitable or unprofitable and would result in a reduction of cash distributions to the partners of the Partnership.

Delay in partnership natural gas or oil production could reduce the Partnership's profitability.

Drilling wells in areas remote from marketing facilities may delay production from those wells until sufficient reserves are established to justify construction of necessary pipelines and production facilities. In addition, marketing demands that tend to be seasonal may reduce or delay production from wells. Wells drilled for the

Partnership may have access to only one potential market. Local conditions including but not limited to closing businesses, conservation, shifting population, pipeline maximum operating pressure constraints, and development of local oversupply or deliverability problems could halt or reduce sales from Partnership wells. Any of these delays in the production and sale of the Partnership's natural gas and oil could reduce the Partnership's profitability, and in that event the cash distributions to the partners of the Partnership would decline.

Information concerning reserves and future net revenues estimates is inherently uncertain.

The accuracy of proved reserves estimates and estimated future net revenues from such reserves is a function of the quality of available geological, geophysical, engineering and economic data and is subject to various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, and other matters. Although it is believed that the estimated proved reserves represent reserves are reasonably certain to recover, actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from the assumptions and estimates used to determine proved reserves. Any significant variance could materially affect the estimated quantities and value of the Partnership's oil and gas reserves, which in turn could adversely affect cash flows, results of operations and the availability of capital resources. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond the Partnership's control. Downward adjustments to the estimated proved reserves could require a write down to the carrying value of the Partnership's oil and gas properties, which would reduce earnings and partners' equity.

The present value of proved reserves will not necessarily equal the current fair market value of the estimated oil and gas reserves. In accordance with the reserve reporting requirements of the SEC, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than those as of the date of the estimate. The timing of both the production and the expenses with respect to the development and production of oil and gas properties will affect the timing of future net cash flows from proved reserves and their present value.

Seasonal weather conditions may adversely affect the Partnership's ability to conduct drilling, completion and production activities in some of the areas of operation.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions. In certain areas, drilling and other oil and natural gas activities are restricted 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.

Item 2. Financial Information.**(a) SELECTED FINANCIAL DATA.**

The selected financial data as of December 31, 2005, and for the period from December 6, 2005 (Date of Inception) to December 31, 2005, presented below were derived from the Partnership's audited financial statements. The selected financial data as of March 31, 2006, and for the three months ended March 31, 2006, were derived from the Partnership's unaudited financial statements. This information is only a summary and should read it conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes thereto appearing elsewhere herein.

	The Three Months Ended March 31, 2006	Period from December 6, 2005 (Date of Inception) to December 31, 2005
Revenues	\$ 420,087	\$ -
Costs and expenses	1,448,664	556,060
Net loss	(1,026,813)	(556,060)
Allocation of net loss:		
Managing General Partner	(308,044)	(6,008)
Investor Partners	(718,769)	(550,052)
Investor Partners - Per Unit	(402)	(308)
Total Assets (As of)	\$ 42,076,628	\$ 42,847,595

(b) MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.**Disclosure Regarding Forward Looking Statements*****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/A, including statements of estimated oil and gas production and reserves, future cash flows and the Partnership's strategies, plans and objectives, are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Although the Partnership believes that its forward looking statements are based on reasonable assumptions, it cautions that such statements are subject to a wide range of risks, trends and uncertainties, incidental to the production and marketing of oil and gas, which could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are important factors that could cause actual results to differ materially from the forward looking statements, including, but not limited to, changes in production volumes, worldwide demand and commodity prices for petroleum natural resources; risks incidental to the 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 derivative activities; and conditions in the capital markets. In particular, careful consideration should be given to cautionary statements made in this Form 10/A in the Risk Factors section. The Partnership undertakes no duty to update or revise these forward-looking statements.

When used in this Form 10/A, the words, "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and

uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under Item 1A. "Risk Factors" and elsewhere in this Form 10/A.

Overview

The Partnership closed its offering of partnership units on December 30, 2005, with capital contributions of \$35,735,509 (1,786.78 units at \$20,000 each) from the Investor Partners and a cash contribution of \$11,231,670 from the Managing General Partner, Petroleum Development Corporation (PDC). A total of \$46,967,179 was contributed by the partners in the aggregate. After payment of syndication costs of \$3,583,551 and a one-time management fee to PDC of \$536,033, the Partnership had available cash of \$42,847,595 to commence Partnership oil and gas well drilling activities.

The Partnership began exploration and development activities immediately after the funding of the Partnership. The full amount of the funding was paid to PDC to begin the drilling of oil and natural gas wells, on behalf of the Partnership under the drilling and operating agreement. The payment to PDC was made as a prepayment of exploration and development costs for oil and gas properties. On December 30, 2005, PDC commenced drilling and by April 4, 2006, a total of 49 wells had been drilled. These 49 wells are the only wells the Partnership will drill, because all of the capital contributions will have been utilized. Once producing, the Partnership's wells will be produced until they are depleted or until they are uneconomical to produce; however, it is the plan of the Partnership and PDC to recompleteness the Codell formation in certain wells in the Wattenberg Field after five or more years of production because it is believed that these wells will have experienced a significant decline in production in that time period. PDC is hopeful that recompleteness will enhance the particular well's reserves and productive capacity. The following table summarizes the Partnership's drilling activities through June 9, 2006.

	<u>Colorado</u>	<u>Wyoming</u>	<u>Total</u>
Drilled, completed and producing	41	-	41
Drilled, completed and awaiting gas pipeline connection	6	-	6
Dry hole	1	-	1
Exploratory dry hole	<u>-</u>	<u>1</u>	<u>1</u>
Totals	<u>48</u>	<u>1</u>	<u>49</u>

All of the wells drilled by the Partnership, except for the Wyoming exploratory well, were development-type wells drilled in Colorado and produce predominantly natural gas along with associated crude oil. The forty-nine wells in the table above are the only wells to be drilled by the Partnership because all of the funds raised in the Partnership offering will have been utilized once the well completion work and pipeline connections on the six non-producing wells are finished. PDC believes that the six remaining wells will be completed, connected and producing by the end of third quarter 2006. The Wyoming exploratory well was fractured in multiple zones and was determined to be a dry hole.

The Colorado wells were drilled in the Wattenberg Field and the Grand Valley Field. Thirty-eight wells were drilled in the Wattenberg Field to the Codell formation or deeper, and the remainder of the Colorado wells were in the Grand Valley Field. The wells drilled in the Grand Valley Field (the Piceance Basin) take longer to drill and are typically more difficult to complete; consequently, the costs of these wells are considerably greater as compared to the Wattenberg wells. As of June 9, 2006, thirty-two wells in the Wattenberg Field and nine wells in the Grand Valley Field were in production.

Results of Operations

No revenue was generated by the Partnership in 2005 because no wells were in production. In accordance with the Partnership Agreement, a one-time management fee equal to 1½% of investors' subscriptions was charged to the Partnership in the amount of \$536,033 by the Managing General Partner. This fee was paid by the Partnership to the Managing General Partner upon funding the Partnership and represents the majority of the loss for the period ended December 31, 2005..

Production commenced during the first quarter of 2006, as wells were drilled, completed and connected to a pipeline. The total production from the Partnership's wells for the quarter ended March 31, 2006, was 12,822 Mcf of natural gas and 5,402 barrels (Bbls) of oil.

The following table presents significant operational information of the Partnership for the three months ended March 31, 2006.

Oil and gas sales	\$	420,087
Gas sales – Mcf		12,822
Average gas price/Mcf	\$	7.18
Oil sales – Bbls		5,402
Average oil price/Bbl	\$	60.71
Production and operating costs	\$	69,656
Production and operating costs/Mcfe	\$	1.54
Depreciation, depletion and amortization	\$	124,896
Net loss	\$	(1,026,813)
Partnership cash distributions	\$	-
Oil and gas price risk management (gain) loss, net:		
Realized gain	\$	(3,717)
Unrealized loss	\$	1,953
Working capital	\$	332,600

•Bbl – One barrel or 42 U.S. gallons of liquid volume.

•Mcf – One thousand cubic feet.

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

In the first quarter of 2006, the Partnership had a net loss of \$1,026,813 resulting primarily from the expensing of \$1,251,357 of exploratory dry hole costs offset in part by the commencement of the production of oil and gas. Additionally, in the second quarter of 2006 the Partnership expects to incur and expense approximately \$475,000 of additional dry hole costs.

The Partnership's future revenues from oil and natural gas sales will be affected by changes in prices. As a result of changes in market conditions, gas prices are highly dependent on the balance between supply and demand. The Partnership's sales prices for natural gas and oil are subject to increases and decreases based on various market sensitive indices.

Liquidity and Capital Resources

Of the \$42,847,595 in net partners' capital contributions originally available for the drilling of wells, a total of \$27,113,040 had been expended as of March 31, 2006, in the drilling, completion and equipping of the 49 wells reflected in the table above although work on some wells is not finished. Of the total amount advanced to the Managing General Partner, \$15,916,517 is remaining for completing and equipping the 34 wells in progress. After the remaining funds have

been expended, no additional wells will be drilled by the Partnership. All of these expenditures are treated as capital expenditures in the financials statements of the Partnership.

As wells are drilled and connected to pipelines, the production phase of operations on the wells begins and will continue for the expected life of the wells or until the wells can no longer be operated economically. As wells are produced and the proceeds from the sale of oil and gas are collected, on behalf of the Partnership, the Managing General Partner will distribute these proceeds, net of production and operating costs and other direct costs, to the partners on a routine basis. Distributions of revenue to partners began in July 2006. Normally, all available funds from the sales of oil and gas, net of operating costs, are distributed monthly and these funds are not retained by the Partnership.

The Partnership had working capital at March 31, 2006, of \$332,600, consisting primarily of receivables from the Managing General Partner related to oil and gas production and operations.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to the understanding of results of operations. This is not a comprehensive list of all of the Partnership's 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 accounting policies are important to the portrayal of the Partnership's financial condition and results of operations and require management's most subjective or complex judgments. In applying those policies, management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, 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 2 - Summary of Significant Accounting Policies" in the Notes to the Financial Statements. The Partnership's critical accounting policies and estimates are as follows:

Use of Estimates in Testing for Impairment of Long-Lived Assets

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 Partnership 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 Partnership 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 Property Accounting

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

In periods prior to receiving a reserve report from an independent petroleum engineer the Partnership relies on the engineers and professionals of its Managing General Partner to provide reserve estimates used to calculate its depreciation and depletion. The Managing General Partner is staffed with experienced petroleum engineers and other professionals who utilize similar methods to estimate reserves as those used by an independent petroleum engineer. The Managing General Partner's engineers consider, along with other data, available geological, geophysical, production and economic data for each reservoir. Data is obtained internally through the Managing General Partner's long history and experience in preparing such estimates, and when available, externally from available public records. Revisions

subsequent to the date of estimate may be necessary as results of drilling, testing and production indicate a revision is appropriate. While the reserve estimates prepared by the Managing General Partner may differ from those prepared by other engineers, its estimation of proved reserves is based on the requirement of reasonable certainty.

Exploratory well drilling costs are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Cumulative costs on in-progress wells "Suspended Well Costs" remain capitalized until their productive status becomes known. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of financial statements, the costs are expensed to exploratory dry hole costs. If a final determination about the productive status of a well is unable to be made prior to issuance of the financial statements, the well is classified as "Suspended Well Costs" until there is sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. When a final determination of a well's productive status is made, the well is removed from the suspended well status and the proper accounting treatment is recorded. The determination of an exploratory well's ability to produce is made within one year from the completion of drilling activities.

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

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

Revenue Recognition

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 marketed by an affiliate of the Managing General Partner under contracts on behalf of the Partnership with terms ranging from one month up to the life of the well. Virtually all of the 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 Partnership's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Partnership believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Managing General Partner currently uses the "net-back" method of accounting for transportation arrangements of natural gas sales. The Managing General Partner 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 the Managing General Partner's customers and reflected in the wellhead price.

Sales of crude oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered from storage tanks at well locations to a purchaser, collection of revenue from the sale is reasonably assured and the sales price is determinable. The Partnership does not refine any of its oil production. The Partnership's crude oil production is sold to purchasers under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

(c) QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

The Partnership's primary market risk exposure is commodity price risk. This exposure is discussed in detail below:

Commodity Price Risk

The Managing General Partner utilizes commodity-based derivative instruments, entered into on behalf of the Partnership, to manage a portion of the Partnership's exposure to price risk from its natural gas sales. These instruments consist of CIG (Colorado Interstate Gas) index-based contracts traded by JP Morgan for Colorado natural gas production. These instruments have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Managing General Partner will receive for the volume of natural gas to which the derivative relates. As a result, while these derivative instruments are structured to reduce the Partnership's exposure to changes in price associated with the derivative commodity, they also limit the benefit the Partnership might otherwise have received from price changes associated with the commodity. The Partnership has adopted the policy of the Managing General Partner prohibiting the use of oil and natural gas future and option contracts for speculative purposes.

Derivative arrangements are entered into by the Managing General Partner on behalf of the Partnership and are reported on the Partnership's balance sheet at fair value as a net short-term or long-term receivable due from or payable to the Managing General Partner. Changes in the fair value of the Partnership's share of derivatives are recorded in the related statement of operations. The Partnership did not have any commodity-based derivatives as of December 31, 2005. The following table summarizes the open derivative positions for the Partnership as of March 31, 2006.

Commodity	Type	Quantity Gas-Mmbtu (a)	Weighted Average Price	Fair Value
Total Positions as of March 31, 2006:				
Natural Gas	Sale Option	15,352	\$ 5.57	\$ (305)
Natural Gas	Purchase Option	3,863	\$ 7.63	\$ (1,648)
Due to Managing General Partner - total				<u>\$ (1,953)</u>
Positions maturing within 12 months following March 31, 2006:				
Natural Gas	Sale Option	11,489	\$ 5.60	\$ 627
Natural Gas	Purchase Option	3,863	\$ 7.63	\$ (1,648)
Due to Managing General Partner - short-term				<u>\$ (1,021)</u>

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

As of March 31, 2006, the maximum term for the derivative positions listed above is 15 months.

Disclosure of Limitations

The Partnership's ultimate realized gain or loss with respect to commodity price fluctuations will depend on the future exposures that arise during the period, the Partnership's hedging strategies at the time and commodity prices at the time.

Item 3. Properties.

The Partnership's properties consist of natural gas wells and the ownership in leasehold acreage in the spacing units for the 49 wells drilled by the Partnership. The acreage associated with the spacing units is designated by state rules and regulations in conjunction with local practice, and final determinations of the leasehold acreage to be assigned to the Partnership from PDC will be made after all drilling and completion activities are finished on all wells. PDC initially and temporarily holds title to the leases, as nominee, to facilitate joint owner operations. (See Item 1. Business.)

The Partnership commenced drilling activities immediately following funding of the Partnership on December 30, and as of December 31, 2005, two wells were in progress. As of June 9, 2006, a total of 49 gross wells (48.6 net) had been drilled and the status as of that date is reflected in the table below. The Partnership's 48 development wells were drilled in Colorado, and one exploratory well was drilled in Wyoming.

	<u>Gross Wells</u>	<u>Net Wells</u>
Development wells:		
Drilled, completed and producing	41	40.9
Drilled, completed and awaiting gas pipeline connection	6	6.0
Dry hole	1	1.0
Exploratory dry hole	<u>1</u>	<u>.7</u>
Total Wells Drilled	<u>49</u>	<u>48.6</u>

The six development wells that have not been completed are expected to be productive once completion work is finished. The exploratory well was drilled during the first quarter of 2006 and was determined to be a dry hole. The forty-nine wells in the table above are the only wells to be drilled by the Partnership since all of the funds raised in the Partnership offering have been utilized.

As of June 9, 2006, the Partnership had 47 productive wells, as follows:

	<u>Gross Wells</u>	<u>Net Wells</u>
Development wells:		
Drilled, completed and producing	41	40.9
Drilled, completed and awaiting gas pipeline connection	<u>6</u>	<u>6.0</u>
Total Productive Wells	<u>47</u>	<u>46.9</u>

A development well is a well which is drilled close to and into the same formation as wells which have already produced and sold oil or natural gas. An exploratory well is one which is drilled in an area where there has been no oil or natural gas production, or a well which is drilled to a previously untested or non-producing zone in an area where there are wells producing from other formations. Productive wells consist of producing wells and wells capable of producing oil and gas in commercial quantities, including gas wells awaiting pipeline connections to commence deliveries. Gross wells refers to the number of wells in which the Partnership has an interest. Net wells refers to gross wells multiplied by the percentage working interest owned by the Partnership.

Production

The Partnership had no production during the period from December 6, 2005 (date of inception) to December 31, 2005. Production commenced during the first quarter of 2006, as wells were drilled, completed and connected to a pipeline. The total production net to the Partnership's interest for the quarter ended March 31, 2006, was 12,822 Mcf of gas and 5,402 Bbls of oil.

Oil and Gas Reserves

Proved oil and gas reserves of the Partnership were not estimated as of December 31, 2005, because no Partnership wells had been completed as of that date. The proved reserves of the Partnership will be estimated by an independent petroleum engineer as of December 31, 2006, as provided for under the partnership agreement.

Title to Properties

The Partnership's interests in producing acreage are in the form of assigned direct interests in leases. Such properties are subject to customary royalty interests generally contracted for in connection with the acquisition of properties and could be subject to liens incident to operating agreements, liens for current taxes and other burdens. As is customary in the oil and gas industry, little or no investigation of title is made at the time of acquisition of undeveloped properties (other than a preliminary review of local mineral records). Investigations are generally made, including in most cases receiving a title opinion of legal counsel, before commencement of drilling operations. A thorough examination of title has been made with respect to all of the Partnership's spacing units on which wells are drilled and the Partnership believes that it has generally satisfactory title to such properties.

Item 4. Security Ownership of Certain Beneficial Owners and Management.

PDC owns a 30% partnership interest in the Partnership.

Certain Shareholders of Petroleum Development Corporation

The following table sets forth information as of July 15, 2006, with respect to the common stock of PDC owned by each person who owns beneficially 5% or more of the outstanding voting common stock, by all directors and executive officers individually, and by all directors and officers as a group.

<u>Name and Address</u>	<u>Beneficial Ownership (1)</u>	
	<u>Number</u>	<u>Percent</u>
Fidelity Management 82 Devonshire Street Boston, MA 021095	2,415,600 (2)	15.0%
Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 9410	1,319,795 (3)	8.2%
Kayne Anderson Rudnick Investment Management LLC 1800 Avenue of the Stars, 2 nd Floor Los Angeles, CA 90067	1,281,289 (4)	7.9%
Steinberg Asset Management LLC 12 East 49 th Street New York, NY 10017	1,104,781 (5)	6.8%
Steven R. Williams 103 East Main Street Bridgeport, WV 26330	421,101 (6)	2.6%
Thomas E. Riley 103 East Main Street Bridgeport, WV 26330	109,700 (7)	*
Eric R. Stearns 103 East Main Street Bridgeport, WV 26330	61,438 (8)	*
Darwin L. Stump 103 East Main Street Bridgeport, WV 26330	30,473 (9)	*
Vincent F. D'Annunzio	18,925	*
Jeffrey C. Swoveland	13,721	*
Donald B. Nestor	2,522	*
Kimberly Luff Wakim	3,031	*
David C. Parke	2,965	*
All directors and executive officers as a group (9 persons)	663,361	4.1%

Less than 1%

- (1) Includes shares over which the person currently holds or shares voting or investment power. Unless otherwise indicated in the footnotes to this table, the persons named in this table have sole voting and investment power with respect to the shares beneficially owned. The percentage column is based upon 16,135,739 shares of PDC common stock outstanding as of June 30, 2006.
- (2) According to the Schedule 13G filed by Fidelity Management with the Securities and Exchange Commission on January 10, 2006.
- (3) According to the Schedule 13G filed by Barclay Global Investors, NA with the Securities and Exchange Commission on July 10, 2006.

- (4) According to the Schedule 13G filed by Kayne Anderson Rudnick Investment Management, LLP with the Securities and Exchange Commission on February 6, 2006.
- (5) According to the Schedule 13F-HR filed by Steinberg Asset Management, LLP with the Securities and Exchange Commission on April 17, 2006.
- (6) Includes 1,467 shares subject to options exercisable within 60 days of June 30, 2006.
- (7) Includes 972 shares subject to options exercisable within 60 days of June 30, 2006.
- (8) Includes 917 shares subject to options exercisable within 60 days of June 30, 2006.
- (9) Includes 862 shares subject to options exercisable within 60 days of June 30, 2006.

Item 5. Directors and Executive Officers.

General Management

The Managing General Partner of the Partnership is Petroleum Development Corporation ("PDC"), a publicly-owned Nevada corporation organized in 1955. The common stock of PDC is traded on the Nasdaq National Market under the symbol "PETD." Since 1969, PDC has been engaged in the business of exploring for, developing and producing oil and natural gas primarily in West Virginia, Tennessee, Pennsylvania, Ohio, Michigan and the Rocky Mountains. As of December 31, 2005, PDC had approximately 150 employees. PDC will make available to Investor Partners, upon request, audited financial statements of PDC for the most recent fiscal year and unaudited financial statements for interim periods. PDC's Internet address is www.petd.com. PDC posts on its Internet Web site its periodic and current reports and other information, including its audited financial statements, that it files with the Securities and Exchange Commission, as well as various charters and other corporate governance information.

PDC will actively manage and conduct the business of the Partnership, devoting its time and talents to management as PDC deems reasonably necessary. PDC will have the full and complete power to do any and all things necessary and incident to the management and conduct of the Partnership's business. PDC will be responsible for maintaining Partnership bank accounts, collecting Partnership revenues, making distributions to the partners, delivering reports to the partners, and supervising the drilling, completion, and operation of the Partnership's natural gas and oil wells.

In addition to managing the affairs of the Partnership, the management and technical staff of PDC also manage the corporate affairs of PDC, the affairs of 75 limited partnerships formed in the current and previous programs, and other joint ventures formed over the years. PDC owns an interest in all of the older limited partnerships and wells. Because PDC must divide its attention and efforts among many unrelated parties, the Partnership will not receive its full attention or efforts at all times.

Experience and Capabilities as Driller/Operator

PDC is contracted to serve as operator for the Partnership wells. Since 1969 PDC has drilled over 2,800 wells in Colorado, West Virginia, Tennessee, Ohio, Michigan, North Dakota, Utah, Wyoming, and Pennsylvania. PDC currently operates approximately 2,800 wells.

PDC employs geologists who develop prospects for drilling by PDC and who help oversee the drilling process. In addition, PDC has an engineering staff that is responsible for well completions, pipelines, and production operations. PDC retains drilling subcontractors, completion subcontractors, and a variety of other subcontractors in the performance of the work of drilling contract wells. In addition to technical management, PDC may provide services, at competitive rates, from PDC-owned service rigs, a water truck, steel tanks used temporarily on the well location during the drilling and completion of a well, roustabouts, and other assorted small equipment and services. A

roustabout is an oil and gas field employee who provides skilled general labor for assembling well components and other similar tasks. PDC may lay short gathering lines, or may subcontract all or part of the work where it is more cost effective for the Partnership. PDC employs full-time well tenders and supervisors to operate its wells. In addition, the engineering staff evaluates reserves of all wells at least annually and reviews well performance against expectations. All services provided by PDC are provided at rates less than or equal to prevailing rates for similar services provided by unaffiliated persons in the area.

Petroleum Development Corporation

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

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

Steven R. Williams was elected Chairman and Chief Executive Officer of PDC in January 2004, following the retirement of James N. Ryan and has served as President of PDC from 1983 to 2004 and Director since 1983.

Thomas E. Riley has served as President since December 2004 and Executive Vice President of Production, Natural Gas Marketing and Business Development from November 2003 to December 2004. Prior thereto, Mr. Riley served as Vice President - Gas Marketing and Acquisitions of PDC from April 1996 to November 2003. Prior to joining PDC, Mr. Riley was president of Riley Natural Gas Company, a natural gas marketing company, from its inception in 1987. PDC acquired Riley Natural Gas in April 1996. Mr. Riley continues to serve as president of PDC's wholly-owned subsidiary. A registered professional engineer, Mr. Riley received a BS degree in petroleum engineering from West Virginia University in 1974.

Eric R. Stearns was appointed Executive Vice President of Exploration and Production in December 2004. Prior thereto, Mr. Stearns was Vice President-Exploration and Development from April 1995 to November 2003 and

Executive Vice President Exploration and Development from November 2003 to December 2004. Mr. Stearns joined PDC in 1985 after working for Hywell, Incorporated and for Petroleum Consultants, Inc. between 1981 and 1985. Mr. Stearns received a BS degree in geology from Virginia Polytechnic Institute and State University in 1981.

Darwin L. Stump has been an officer of PDC since April 1995 and held the position of Corporate Controller from 1980 to November 2003. Mr. Stump was appointed Acting Chief Financial Officer (CFO) of PDC in October 2003 following the death of Dale G. Rettinger. The board of directors named Mr. Stump CFO in November 2003. Prior to joining PDC, Mr. Stump was a senior accountant with Main Hurdman, Certified Public Accountants. Mr. Stump is a CPA, a member of the AICPA, the West Virginia Society of CPAs and a graduate of West Virginia University with a B.S. degree in accounting.

Gregory A. Morgan is a partner in the Clarksburg, West Virginia law firm of Young Morgan & Cann, PLLC. He was elected corporate secretary of PDC in September 2004. He graduated from West Virginia University in 1980, and from the West Virginia College of Law in 1983. He served as an Assistant Attorney General of West Virginia from 1983 to 1986. He currently also serves as Clarksburg's City Attorney.

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, Inc., Pittsburgh, Pennsylvania since September 2000. Prior thereto, Mr. Swoveland was Vice President-Finance and Treasurer of Equitable Resources, Inc. since September 1994. Mr. Swoveland received an MS degree in finance from Carnegie Mellon University.

Donald B. Nestor is a Certified Public Accountant and a Partner in the CPA firm of Toothman, Rice, PLLC 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 a CPA, is a Partner with the Pittsburgh, Pennsylvania law firm, Thorp, Reed & Armstrong LLP, where she serves as a member of the Executive Committee. Ms. Wakim has practiced law with Thorp, Reed & Armstrong LLP since 1990.

David C. Parke joined Mufson/Howe/Hunter & Company LLC, an investment banking firm focused on the needs of emerging growth and middle market companies, as a founder and director in 2003. From 1992 to 2003, Mr. Parke was director of 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. Mr. Parke received his MBA with honors from The Wharton School of the University of Pennsylvania and graduated summa cum laude and Phi Beta Kappa from Lehigh University with a BS in finance.

The principal standing committees of PDC's Board of Directors include the Audit Committee, Compensation Committee, Nominating and Governance Committee, Qualified Legal Compliance Committee and the Executive Committee. Each such committee operates under a written charter. The Audit Committee of the Board of Directors is comprised of Directors Nestor, Swoveland and Wakim. The Board has determined that the Audit Committee 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.

Item 6. Executive Compensation.

None of PDC's officers or directors will receive any direct remuneration or other compensation from the Partnership. These persons will receive compensation solely from PDC. Information as to compensation paid by PDC to its directors and executive officers may be obtained from publicly available reports filed by PDC with the Securities and Exchange Commission under the Securities Exchange Act of 1934. This information is available on PDC's Internet Web site www.petd.com and may be viewed on and retrieved from the PDC Web site.

COMPENSATION TO THE MANAGING GENERAL PARTNER AND AFFILIATES

The items of compensation to be paid to the Managing General Partner and its affiliates from the Partnership are summarized in the table set forth below. The items are discussed in more detail following the table.

<u>Recipient</u>	<u>Item of Compensation</u>	<u>Amount</u>
Affiliate	Brokerage sales commissions; reimbursement of due diligence, marketing support expenses; and wholesaling fees	Maximum of 10½% of subscriptions - \$3,583,551
Managing General Partner	Management fee	1½% of subscriptions - \$536,033
Managing General Partner	Managing General Partner's drilling compensation	14% of total well costs for operated wells
Managing General Partner	Purchased partnership interest	30% partnership interest
Managing General Partner	Direct costs	Cost
Managing General Partner	Sale of leases to the partnership	The lower of cost or fair market value
Managing General Partner	Contract drilling rates	Cost
Managing General Partner and Affiliates	Payment for equipment and supplies	Cost
Managing General Partner	Operator's monthly per-well charges and services	Competitive prices
Managing General Partner and Affiliates	Gas marketing charges	Competitive rates

Following closing of the Partnership's offering and funding of the Partnership, PDC contributed to the Partnership an amount in cash equal to 31.4% of the subscriptions from the Investor Partners. In exchange for PDC's investment, PDC received a 30% interest in the profits and losses of the Partnership.

Compensation Associated with Drilling and Completion and Production Operations

Managing General Partner and Operator Compensation The Managing General Partner is serving as operator for the Partnership's wells. PDC will receive drilling compensation equal to 14% of the total well costs paid from the funds of the Investor Partners for its services as Managing General Partner and operator of the Partnership's wells and for contributing its leases at cost.

Natural Gas and Oil Revenues The limited partnership agreement provides for the allocation of revenues from natural gas and oil production 70% to the Investors Partners and 30% to PDC. However, the partnership sharing arrangements may be revised in the event PDC invests capital above PDC's required minimum capital contribution to cover additional tangible drilling and lease costs, in which case PDC's share would increase. See "Participation in Costs and Revenues" in Item 9 below.

Drilling Costs The Partnership entered into the drilling and operating agreement with the Managing General Partner to drill and complete the Partnership's wells at cost plus the Managing General Partner's drilling compensation of 14% of the total well cost. If the Managing General Partner provides other services in the drilling and completion of the wells, it will charge those services at its cost, not to exceed competitive rates charged in its area of operation, and these charges will be included in the total well cost when determining the Managing General Partner's drilling compensation.

Cost, when used with respect to services, generally means the reasonable, necessary, and actual expense incurred in providing the services, determined in accordance with generally accepted accounting principles. The cost of the well also includes all ordinary costs of drilling, testing and completing the well. Following are some of the costs of a natural gas well, which will be the classification of the majority of the wells:

- location and surface damages;
- location construction;
- drilling;
- logging;
- completion including multiple completions, which means, in general, treating separately all potentially productive geological formations in an attempt to enhance the gas production from the well;
- well casing pipe and surface production equipment;
- installing gathering lines for natural gas; and
- fixed rate overhead in accordance with industry accounting standards (COPAS).

The well costs charged to the Partnership will be proportionately reduced to the extent the Partnership acquires less than 100% of the working interest in a prospect. The amount of compensation that the Managing General Partner could earn as a result of these arrangements depends on the degree to which it provides services for the wells, and the number and type of wells that are drilled. If the Managing General Partner supplies other goods and services to the Partnership, it will be required to supply them at cost, and they will be included in the total well costs for determining the Managing General Partner's and the investors' contributions, the division of oil and gas revenues, and calculation of the Managing General Partner's drilling compensation.

Per Well Charges

Under the drilling and operating agreement, the Managing General Partner, as operator of the wells, will receive the following from the Partnership when the wells begin producing:

- reimbursement at actual cost for all direct expenses incurred on behalf of the Partnership,
- monthly well operating charges for operating and maintaining the wells during producing operations at a competitive rate, and
- monthly administration charge for Partnership activities.

During the production phase of operations, the operator will receive for each producing well a monthly fee based upon competitive industry rates for operations and field supervision and \$100 for Partnership accounting, engineering, management, and general and administrative expenses. The operator will bill non-routine operations and administration costs to the Partnership at its cost. The Managing General Partner may not benefit by interpositioning itself between the Partnership and the actual provider of operator services. In no event will any consideration received for operator services be duplicative of any consideration or reimbursement received under the partnership agreement.

The well operating charges cover all normal and regular recurring operating expenses for the production, delivery, and sale of natural gas and oil, such as:

- well tending, routine maintenance, and adjustment;
- reading meters, recording production, pumping, maintaining appropriate books and records; and
- preparing production related reports to the Partnership and government agencies.

The well supervision fees do not include costs and expenses related to:

- the purchase of equipment, materials, or third-party services;
- the cost of compression and third-party gathering services, or gathering costs;
- brine disposal; and
- rebuilding of access roads.

These costs will be charged at the invoice cost of the materials purchased or the third-party services performed.

Gathering, Compression and Processing Fees

Under the limited partnership agreement, the Managing General Partner will be responsible for gathering, compression, processing and transporting the natural gas produced by the Partnership to interstate pipeline systems, local distribution companies, and/or end-users in the area from the point the gas from the well is commingled with gas from other wells. In such a case, the Managing General Partner anticipates that it will use gathering systems already owned by PDC or that PDC will construct the necessary facilities if no such line exists. In such a case, the Partnership will pay a gathering, compression and processing fee directly to the Managing General Partner at competitive rates. If a third-party gathering system is used, the Partnership will pay a gathering fee to the third-party gathering the natural gas.

Gas Marketing and Other Fees

PDC and its affiliates may enter into other transactions with the Partnership for services, supplies and equipment during the production phase of the Partnership, and will be entitled to compensation at competitive prices and terms as determined by reference to charges of unaffiliated companies providing similar services, supplies and equipment. PDC intends to market some of the gas produced through its subsidiary, Riley Natural Gas. Charges for those services will be at competitive rates.

Item 7. Certain Relationships and Related Transactions.

The Registrant hereby incorporates herein by reference the disclosure presented in Item 6 above.

Item 8. Legal Proceedings.

The Registrant is not subject to any legal proceedings.

PDC as driller/operator is subject to minor legal proceedings arising from the normal course of business. Any outstanding and pending legal actions are not considered material to the operations of the Partnership or PDC.

Item 9. Market Price of and Dividends on the Registrant's Common Equity and Related Stockholder Matters.

Market. There is no public market for the units nor will a public market develop for the units in the future. Investor Partners may not be able to sell their Partnership interests or may be able to sell them only for less than fair market value. The offer and sale of the Partnership's additional general partnership interests and limited partnership interests ("units") have not been registered under the Securities Act or under any state securities laws. Each purchaser of units was required to represent that such investor was purchasing the units for his or her own account for investment and not with a view to resale or distribution. No transfer of a unit may be made unless the transferee is an "accredited investor" and such transfer is registered under the Securities Act and applicable state securities laws, or an exemption therefrom is available. The Partnership may require that the transferor provide an opinion of legal counsel stating that the transfer complies with all applicable securities laws. A sale or transfer of units by an Investor Partner requires PDC's prior written consent. For these and other reasons, an investor must anticipate that he or she will have to hold his or her partnership interests indefinitely and will not be able to liquidate his or her investment in the

Partnership. Consequently, an investor must be able to bear the economic risk of investing in the Partnership for an indefinite period of time.

Cash Distribution Policy. PDC plans to make distributions of Partnership cash on a monthly basis, but will make distributions no less often than quarterly, if funds are available for distribution. In general, PDC will make cash distributions of 70% to the Investor Partners and 30% to the Managing General Partner throughout the term of the Partnership. Cash will be distributed to the Investor Partners and PDC as a return on capital, in the same proportion as their interest in the net income of the Partnership. However, no Investor Partner will receive distributions to the extent the distributions would create or increase a deficit in that partner's capital account.

PDC cannot presently predict amounts of cash distributions, if any, from the Partnership. However, PDC expressly conditions any distribution upon its having sufficient cash available for distribution. Sufficient cash available for distribution is defined to generally mean cash generated by the Partnership in excess of the amount the Managing General Partner determines is necessary or appropriate to provide for the conduct of its business, to comply with applicable law, to comply with any debt instruments or other agreements or to provide for future distributions to its unitholders. In this regard, PDC will review the accounts of the Partnership at least quarterly for the purpose of determining the sufficiency of distributable cash available for distribution. Amounts will be paid to partners only after payment of fees and expenses to the Managing General Partner and its affiliates and only if there is sufficient cash available. The ability of the Partnership to make or sustain cash distributions will depend upon numerous factors. PDC can give no assurance that any level of cash distributions to the Investor Partners of the Partnership will be attained, that cash distributions will equal or approximate cash distributions made to investors in prior drilling programs sponsored by PDC, or that any level of cash distributions can be maintained.

In general, the volume of production from producing properties declines with the passage of time. The cash flow generated by the Partnership's activities and the amounts available for distribution to the Partnership's respective partners will, therefore, decline in the absence of significant increases in the prices that the Partnership receives for its oil and natural gas production, or significant increases in the production of oil and natural gas from prospects resulting from the successful additional development of these prospects. If the Partnership decides to develop its wells further, the funds necessary for that development would come from the Partnership's revenues and/or from borrowed funds. As a result, there may be a decrease in the funds available for distribution, and the distributions to the Investor Partners may decrease.

PDC intends to develop the Partnership's interests in its prospects only with the proceeds of subscriptions and PDC's capital contributions. However, these funds may not be sufficient to fund all costs, and it may be necessary for the Partnership to retain Partnership revenues for the payment of these costs, or for PDC to advance the necessary funds to the Partnership or for the Partnership to borrow necessary funds. It is likely that the Partnership's Wattenberg Field, Colorado wells will benefit from recompletion services, generally in five to seven years following initial drilling of those wells. Recompletion is the process of going into an existing zone which is already producing for a refrac, or going into a new zone at a different depth, all with the objective of increasing the production of oil or natural gas. If PDC retains Partnership revenues for the payment of these recompletion or refrac costs, the amount of Partnership funds available for distribution to the partners of the Partnership will decrease correspondingly. Development work will not include the drilling of any wells beyond the initial wells that have been drilled. PDC will retain payment for the recompletion or refrac work from Partnership proceeds in one of two methods:

- PDC will prepare an authority for expenditures (an "AFE") estimate for the Partnership; PDC will complete the development work and will bill the Partnership for the work performed and will be reimbursed from future production; or
- PDC will prepare an AFE estimate for the Partnership; the Partnership will retain revenues from operations until it has accumulated sufficient funds to pay for the development work, at which time PDC will commence the work, and PDC will be reimbursed as the work progresses from retained revenues.

The choice of which option to use will be at PDC's discretion, based on the amount of the anticipated expenditure and the urgency of the necessary work.

The limited partnership agreement permits the Partnership to borrow funds on behalf of the Partnership for Partnership activities. The Partnership may borrow needed funds, or receive advances, from the Managing General Partner or affiliates of the Managing General Partner or from unaffiliated persons. On loans or advances made available to the Partnership by the Managing General Partner or affiliates of the Managing General Partner, the Managing General Partner or affiliate may not receive interest in excess of its interest costs, nor may the Managing General Partner or affiliate receive interest in excess of the amounts which would be charged the Partnership (without reference to the Managing General Partner's financial abilities or guarantees) by unrelated banks on comparable loans for the same purpose. The Managing General Partner anticipates that borrowed funds will be utilized to finance Codell recompletion activities (see Item 1-Business).

Investors who are independent producers will be entitled to claim a percentage depletion deduction against their oil and gas income. The percentage depletion rate for oil and gas properties is generally 15% of the gross income generated by the property.

PARTICIPATION IN COSTS AND REVENUES

Profits and Losses; Cash Distributions

The limited partnership agreement provides for the allocation of profits and losses during the production phase of the Partnership and for the distribution of cash available for distribution between Investor Partners and PDC, as follows:

	<u>Investor Partners</u>	<u>PDC, Managing General Partner</u>
Throughout term of Partnership	70%	30%

Sharing Arrangements The limited partnership agreement provides for the allocation of Partnership profits and losses 70% to the Investor Partners and 30% to PDC throughout the term of the Partnership. However, amounts will be paid to the partners only after payment of fees and expenses to the Managing General Partner and its affiliates and only if there is sufficient cash available. The foregoing allocation of profits and losses is an allocation of each item of income, gain, loss, and deduction which, in the aggregate, constitute a profit or a loss.

Revenues

Natural Gas and Oil Revenues; Sales Proceeds The limited partnership agreement provides for the allocation of revenues from natural gas and oil production and gain or loss from the sale or other disposition of productive wells and leases 70% to the Investor Partners and 30% to PDC. However, the partnership sharing arrangements may be revised in the event PDC invests capital above PDC's required minimum capital contribution to cover additional tangible drilling and lease costs, in which case PDC's share would increase. See "Lease Costs, Tangible Well Costs, and Gathering Line Costs" below.

Interest Income PDC will allocate and credit interest earned on the deposit of operating revenues and revenues from any other sources in the same percentages that oil and natural gas revenues are then being allocated to the Investor Partners and PDC.

Sale of Equipment PDC will allocate all revenues from sales of equipment in the same percentages as oil and natural gas revenues are then being allocated.

Sale of Productive Properties In the event of the sale or other disposition of a productive well, a lease upon which the well is situated, or any equipment related to that lease or well, PDC will allocate and credit to the Investor Partners and PDC the gain from the sale or disposition in the same percentages as oil and gas revenues are then being allocated. The term "proceeds" above does not include revenues from a royalty, overriding royalty, lease interest reserved, or other promotional consideration reserved by the Partnership in connection with any sale or disposition.

PDC will allocate these revenues to the Investor Partners and PDC in the same percentages as the allocation of oil and natural gas revenues.

Costs

Lease Costs, Tangible Well Costs, and Gathering Line Costs: PDC pays 100% of the costs of leases, tangible well costs and gathering line costs.

PDC will contribute and/or pay for the Partnership's share of all leases, tangible drilling and completion costs, and gathering line costs, but not less than 30% of the well costs excluding PDC's drilling compensation. If these costs exceed PDC's required capital contribution, PDC will increase its capital contribution. In that event, PDC's share of all items of profit and loss during the production phase of operations and cash available for distribution would be modified to equal the percentage arrived at by dividing PDC's capital contributions by the total well costs, excluding PDC's drilling compensation; the Investor Partners' allocations of these items would be changed accordingly.

Intangible Drilling Costs (IDC): Intangible drilling costs are costs required to drill a well and prepare the well for production. These costs have no salvage value. Items such as the cost of drilling and completing the well, the cost of grading the surface, labor costs, and geological costs associated with selecting a well site are intangible well costs. IDC will be allocated 100% to the Investor Partners.

Operating Costs: Operating costs are the costs at the well level associated with producing and maintaining productive wells, such as well tending charges, painting equipment and maintaining access roads. PDC will allocate and charge operating costs of Partnership wells 70% to the Investor Partners and 30% to PDC.

Direct Costs: Direct costs are Partnership level costs, primarily professional fees of the independent auditor and reserve engineer and tax return preparation and other similar costs. PDC will allocate and charge direct costs of the Partnership 70% to the Investor Partners and 30% to PDC.

The table below summarizes the participation of the Investor Partners and PDC, taking account of PDC's capital contribution, in the costs and revenues of the Partnership:

	<u>Investor Partners</u>	<u>Managing General Partner</u>
Partnership Costs		
Broker-dealer Commissions and Expenses	100%	0%
Management Fee	100%	0%
Undeveloped Lease Costs	0%	100%
Tangible Well Costs	0%	100%
Intangible Drilling Costs (IDC)	100%	0%
Managing General Partner's Drilling Compensation	100%	0%
Operating Costs	70%	30%
Direct Costs	70%	30%
Partnership Revenues		
Sale of Oil and Gas Production	70%	30%
Sale of Productive Properties	70%	30%
Sale of Equipment	70%	30%
Sale of Undeveloped Leases	70%	30%
Interest Income	70%	30%

Allocations Among Investor Partners; Deficit Capital Account Balances

PDC will allocate the Investor Partners' share of revenues and costs of the Partnership among them in the same proportion as each Investor Partner's capital contribution bears to the aggregate of the capital contributions of all Investor Partners in the Partnership.

To avoid the requirement of restoring a deficit capital account balance, there will be no allocations of losses to an Investor Partner to the extent those allocations would create or increase a deficit in his or her capital account (adjusted for liabilities, as provided in the limited partnership agreement).

Termination

Upon termination and final liquidation of the Partnership, PDC will distribute the assets of the Partnership to the partners based upon their capital account balances. If PDC has a deficit in its capital account, PDC must restore the deficit; however, no Investor Partner will be obligated to restore his or her deficit, if any.

Amendment of Partnership Allocation Provisions

PDC is authorized to amend the limited partnership agreement, if, in its sole discretion based on advice from its legal counsel or accountants, an amendment to revise the cost and revenue allocations is required for those allocations to be recognized for federal income tax purposes because of either the promulgation of Treasury Regulations or other developments in the tax law. Any new allocation provisions provided by an amendment must be made in a manner that would result in the most favorable aggregate consequences to the Investor Partners as nearly as possible consistent with the original allocations described in the limited partnership agreement. See Section 11.09 of the limited partnership agreement.

Item 10. Recent Sales of Unregistered Securities.

The Registrant was funded on December 30, 2005 upon completion of the private placement of its securities. The offering was made solely to accredited investors, as that term is defined by Rule 501(a) under the Securities Act of 1933, and was effected in reliance upon § 4(2) of the Securities Act and Rule 506 thereunder. The Partnership sold for cash \$35,735,709 of its securities in the offering. The dealer-manager of the offering was PDC Securities Incorporated, a NASD-registered broker-dealer. PDC Securities Incorporated is an affiliate of Petroleum Development Corporation, the Managing General Partner of the Partnership.

Item 11. Description of Registrant's Securities to be Registered.

Units of Partnership Interest. In its offering, the Partnership sold units of general partnership interest and units of limited partnership interest in the partnership. "Unit" means the partnership interest purchased by a limited partner or an additional general partner. This interest is the right and obligation to share a proportional part of the Investor Partners' share of Partnership income, expense, assets and liabilities. The fractional interest purchased by a one unit investment in the Investor Partners' interest in the Partnership is the ratio of one unit to the total number of units sold. An additional general partner will be able to apply tax deductions generated by the Partnership to reduce his/her federal adjusted gross income regardless of the source of the income, but he/she will have unlimited liability for the drilling and completion activities of the Partnership. An individual investor who invested as a limited partner will be able to use his/her deductions to reduce taxable income only from passive sources. The Internal Revenue Service defines passive income as income from partnership and rental activities. One's liability as a limited partner is restricted to his/her investment in the Partnership.

Conversion of Units by the Managing General Partner and by Additional General Partners. PDC will convert all units of additional general partnership interest of the Partnership into the same dollar amount of units of limited partnership interest of the Partnership upon completion of drilling and completion operations of the Partnership. Prior to that time, additional general partners may convert their units of additional general partnership interest into units of limited partnership interest if there is a material change in the amount of the Partnership's insurance coverage. PDC must notify the additional general partners if there is a material reduction of the insurance coverage, and those partners

will be able to require PDC to convert their interests any time during the 30 days preceding the change. Additional general partners will not be able to convert their interest if the conversion would cause a termination of the Partnership for federal tax purposes.

SUMMARY OF LIMITED PARTNERSHIP AGREEMENT

The limited partnership agreement in the form filed as an exhibit to this registration statement will govern all partners' rights and obligations. The following statements concerning the limited partnership agreement are merely a summary of all the material terms of the limited partnership agreement, but do not purport to be complete and in no way amend or modify the limited partnership agreement.

Responsibility of Managing General Partner

The Managing General Partner shall have the exclusive management and control of all aspects of the business of the Partnership. Sections 5.01 and 6.01 of the limited partnership agreement. No Investor Partner shall have any voice in the day-to-day business operations of the Partnership. Section 7.01. The Managing General Partner is authorized to delegate and subcontract its duties under the limited partnership agreement to others, including entities related to it. Section 5.02.

Liability of General Partners, Including Additional General Partners

General partners, including additional general partners, will have unlimited liability for Partnership activities. The additional general partners will be jointly and severally liable for all obligations and liabilities to creditors and claimants, whether arising out of contract or tort, in the conduct of Partnership operations. Section 7.12.

PDC, as operator, maintains general liability insurance. In addition, PDC has agreed to indemnify each additional general partner for obligations related to casualty and business losses which exceed available insurance coverage and Partnership assets. Section 7.02.

The additional general partners, by execution of the limited partnership agreement, grant to the Managing General Partner the exclusive authority to manage the Partnership business in its sole discretion and to bind the Partnership and all partners in its conduct of the Partnership business. The additional general partners may not participate in the management of the Partnership business; and the limited partnership agreement prohibits the additional general partners from acting in a manner harmful to the assets or the business of the Partnership or to do any other act which would make it impossible to carry on the ordinary business of the Partnership. If an additional general partner acts contrary to the terms of the limited partnership agreement, losses caused by his or her actions will be borne by that additional general partner alone and that additional general partner may be liable to other partners for all damages resulting from his or her breach of the limited partnership agreement. Section 7.01. Additional general partners who choose to assign their units in the future may do so only as provided in the limited partnership agreement. Liability of partners who have assigned their units may continue after the assignment unless a formal assumption and release of liability is affected. Section 7.03.

Liability of Limited Partners

The West Virginia Uniform Limited Partnership Act governs the Partnership, under which law a limited partner's liability for the obligations of the Partnership is limited to his or her capital contribution, his or her share of Partnership assets and the return of any part of his or her capital contribution for a period of one year after the return (or six years in the event the return is in violation of the limited partnership agreement). A limited partner will not otherwise be liable for the obligations of the Partnership unless, in addition to the exercise of his or her rights and powers as a limited partner, the person takes part in the control of the business of the Partnership. Section 7.01.

Allocations and Distributions

General: Profits and losses are to be allocated and cash is to be distributed in the manner described in Item 6 "Executive Compensation" and Item 9 "Market Price of and Dividends on the Registrant's Common Equity and Related Stockholder Matters," above. See Article III of the limited partnership agreement.

Time of Distributions: The Managing General Partner will determine and distribute not less frequently than quarterly cash available for distribution. Section 4.01. The Managing General Partner may, at its discretion, make distributions more frequently. Notwithstanding any other provision of the limited partnership agreement to the contrary, no partner will receive any distribution to the extent the distribution will create or increase a deficit in that partner's capital account (as increased by his or her share of partnership minimum gain). Section 4.03.

Liquidating Distributions: Liquidating distributions will be made in the same manner as regular distributions; however, in the event of dissolution of the Partnership, distributions will be made only after due provision has been made for, among other things, payment of all Partnership debts and liabilities. Section 9.03.

Voting Rights

Investor Partners owning 10% or more of the then outstanding units entitled to vote have the right to require the Managing General Partner to call a meeting of the partners. Section 7.07.

Investor Partners may vote with respect to Partnership matters. A majority in interest of the then outstanding units entitled to vote constitutes a quorum. Each unit is entitled to one vote on all matters; each fractional unit is entitled to that fraction of one vote equal to the fractional interest in the unit. Except as otherwise provided in the limited partnership agreement, at any meeting of Investor Partners, approval of any matters considered at the meeting requires the affirmative vote of a majority of units represented, in person or by proxy, at the meeting at which a quorum is present. Approval of any of the following matters requires the affirmative vote of a majority of the then outstanding units entitled to vote, without the concurrence of the Managing General Partner:

- The sale of all or substantially all of the assets of the Partnership;
- Removal of the Managing General Partner and election of a new managing general partner;
- Dissolution of the Partnership;
- Any non-ministerial amendment to the limited partnership agreement;
- Cancellation of contracts for services with the Managing General Partner or affiliates; and
- The appointment of a liquidating trustee in the event the Partnership is to be dissolved by reason of the retirement, dissolution, liquidation, bankruptcy, death, or adjudication of insanity or incapacity of the last remaining general partner.

Additionally, the Partnership is not permitted to participate in a roll-up transaction unless the roll-up has been approved by at least 66 2/3% interest of Investor Partners. Sections 5.07(m) and 7.08.

The Managing General Partner, if it were removed by the Investor Partners, may elect to retain its interest in the Partnership as a limited partner in the successor limited partnership (assuming that the Investor Partners determined to continue the Partnership and elected a successor managing general partner), in which case the former Managing General Partner would be entitled to vote its interest as a limited partner. Section 7.06.

Investor Partners may review the Partnership's books and records and list of Investor Partners at any reasonable time and may copy the list of Investor Partners at their expense. Investor Partners may submit proposals to the Managing General Partner for inclusion in the voting materials for the next meeting of Investor Partners for consideration by the Investor Partners. With respect to the merger or consolidation of the Partnership or the sale of all

or substantially all of the Partnership's assets, Investor Partners may exercise dissenter's rights for fair appraisal of their units in accordance with Section 31D-13-1302 of the West Virginia Business Corporation Act. Sections 7.07, 7.08, and 8.01.

Retirement and Removal of the Managing General Partner

If the Managing General Partner desires to withdraw from the Partnership for whatever reason, it may do so only upon one hundred twenty (120) days prior written notice and with the written consent of the Investor Partners owning a majority of the then outstanding units. Section 6.03.

If the Investor Partners desire to remove the Managing General Partner, they may do so at any time with the consent of the Investor Partners owning a majority of the then outstanding units, and upon the selection of a successor managing general partner by the Investor Partners owning a majority of the then outstanding units. Section 7.06.

Term and Dissolution

The Partnership will continue for a maximum period ending December 31, 2055 unless earlier dissolved upon the occurrence of any of the following:

- the written consent of the Investor Partners owning a majority of the then outstanding units;
- the retirement, bankruptcy, adjudication of insanity or incapacity, withdrawal, removal, or death (or, in the case of a corporate managing general partner, the retirement, withdrawal, removal, dissolution, liquidation, or bankruptcy) of a managing general partner, unless a successor managing general partner is selected by the partners under the limited partnership agreement or the remaining managing general partner, if any, continues the Partnership's business;
- the sale, forfeiture, or abandonment of all or substantially all of the Partnership's property; or
- the occurrence of any event causing dissolution of the Partnership under the laws of the State of West Virginia. Section 9.01.

Reports to Partners

The Managing General Partner will furnish to the Investor Partners of the Partnership semi-annual and annual reports which will contain financial statements (including a balance sheet and statements of income, partners' equity and cash flows), which statements at fiscal year end will be audited by an independent accounting firm. Financial statements furnished in the Partnership's semi-annual reports will not be audited. Semi-annually, all Investor Partners will also receive a summary itemization of the transactions between the Managing General Partner or any affiliate and the Partnership showing all items of compensation received by the Managing General Partner and its affiliates. Annually beginning with the fiscal year ended December 31, 2006, oil and gas reserve estimates prepared by an independent petroleum engineer will also be furnished to the Investor Partners. Annual reports will be provided to the Investor Partners within 120 days after the close of the Partnership fiscal year, and semi-annual reports will be provided within 75 days after the close of the first six months of the Partnership fiscal year. In addition, the Investor Partners will receive on a monthly basis while the Partnership is participating in drilling and completion activities, reports containing a description of the Partnership's acquisition of interests in prospects, including farmins and farmouts, and the drilling, completion and abandonment of wells thereon. All Investor Partners will receive a report containing information necessary for the preparation of their federal income tax returns and any required state income tax returns by March 15 of each calendar year. Investor Partners will also receive in the monthly reports a summary of the status of wells drilled by the Partnership, the amount of oil or gas from each well and the drilling schedule for proposed wells, if known. The Managing General Partner may provide other reports and financial statements as it deems necessary or desirable. Section 8.02.

Power of Attorney

Each partner has granted to the Managing General Partner a power of attorney to execute documents deemed by the Managing General Partner to be necessary or convenient to the partnership's business or required in connection with the qualification and continuance of the partnership. Section 10.01.

Item 12. Indemnification of Directors and Officers.

The Managing General Partner will be entitled to reimbursement and indemnification for all expenditures made (including amounts paid in settlement of claims) or losses or judgments suffered by it in the ordinary and proper course of the Partnership's business, provided that the Managing General Partner has determined in good faith that the course of conduct which caused the loss or liability was in the best interests of the Partnership, that the Managing General Partner was acting on behalf of or performing services for the Partnership, and that the expenditures, losses or judgments were not the result of the negligence or misconduct on the part of the Managing General Partner. Section 6.04. The Managing General Partner will have no liability to the Partnership or to any partner for any loss suffered by the Partnership which arises out of any action or inaction of the Managing General Partner if the Managing General Partner, in good faith, determined that the course of conduct was in the best interest of the Partnership and the course of conduct did not constitute negligence or misconduct of the Managing General Partner. The Managing General Partner will be indemnified by the Partnership to the limit of the insurance proceeds and tangible net assets of the Partnership against any losses, judgments, liabilities, expenses and amounts paid in settlement of any claims sustained by it in connection with the Partnership, provided that the same were not the result of negligence or misconduct on the part of the Managing General Partner.

Notwithstanding the above, the Managing General Partner will not be indemnified for liabilities arising under federal and state securities laws unless

- there has been a successful adjudication on the merits of each count involving securities law violations; or
- the claims have been dismissed with prejudice on their merits by a court of competent jurisdiction; or
- a court of competent jurisdiction approves a settlement of the claims against a particular indemnitee and finds that indemnification of the settlement and the related costs should be made, and the court considering the request for indemnification has been advised of the position of the Securities and Exchange Commission and of the position of any state securities regulatory authority in which securities of the Partnership were offered or sold as to indemnification for violations of securities laws;
- provided, however, the court need only be advised of the positions of the securities regulatory authorities of those states (a) which are specifically set forth in the Partnership's offering memorandum and (b) in which plaintiffs claim they were offered or sold Partnership units.

In any claim for indemnification for federal or state securities laws violations, the party seeking indemnification must place before the court the position of the Securities and Exchange Commission, the Massachusetts Securities Division, and the Tennessee Securities Division or other respective state securities division with respect to the issue of indemnification for securities laws violations.

The Partnership will not incur the cost of the portion of any insurance which insures any party against any liability as to which the party is prohibited from being indemnified. Section 6.04.

Item 13. Financial Statements and Supplementary Data.

See Financial Statements starting at page F-1 attached.

Item 14. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures.

Not applicable.

Item 15. Financial Statements and Exhibits.

- (a) The index to Financial Statements is located at page F-2.
- (b) Exhibits. The following documents are filed as exhibits to this registration statement.

Exhibit Ref. No.	Description
3.	Form of Limited Partnership Agreement

SIGNATURES

Pursuant to the requirements of Section 12 of the Securities Exchange Act of 1934, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized.

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(Registrant)

By: Petroleum Development Corporation
Managing General Partner

Date: July __, 2006

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

Date: July __, 2006

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

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Financial Statements

For the Three Months Ended March 31, 2006 (Unaudited)
and
Period from December 6, 2005 (Date of Inception) to December 31, 2005
(With Independent Registered Public Accounting Firm's Report Thereon)

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ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Report of Independent Registered Public Accounting Firm

To the Partners

Rockies Region Private Limited Partnership:

We have audited the accompanying balance sheet of Rockies Region Private Limited Partnership as of December 31, 2005 and the related statements of operations, partners' equity and cash flows for the period from December 6, 2005 (date of inception) to December 31, 2005. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Rockies Region Private Limited Partnership as of December 31, 2005, and the results of its operations and its cash flows for the period from December 6, 2005 (date of inception) to December 31, 2005, in conformity with U.S. generally accepted accounting principles.

KPMG LLP

Pittsburgh, Pennsylvania
April 27, 2006

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Balance Sheets

	<u>March 31, 2006</u> (Unaudited)	<u>December 31, 2005</u>
Assets		
Current assets:		
Accounts receivable - oil and gas sales	\$ 423,304	\$ -
Total current assets	<u>423,304</u>	<u>-</u>
Oil and gas properties, successful efforts method:		
Oil and gas properties	7,741,567	-
Wells in progress	18,120,136	315,408
	<u>25,861,703</u>	<u>315,408</u>
Less accumulated depreciation, depletion and amortization	(124,896)	-
	<u>25,736,807</u>	<u>315,408</u>
Prepayments for development of oil and gas properties	15,916,517	42,532,187
Total oil and gas properties, net	<u>41,653,324</u>	<u>42,847,595</u>
Total Assets	<u><u>\$ 42,076,628</u></u>	<u><u>\$ 42,847,595</u></u>
Liabilities and Partners' Equity		
Current liabilities:		
Accrued expenses	\$ 9,683	\$ 20,027
Due to Managing General Partner – derivatives, short term	1,021	-
Total current liabilities	<u>90,704</u>	<u>20,027</u>
Due to Managing General Partner – derivatives, long term	932	-
Asset retirement obligations	184,237	-
Partners' Equity	<u>41,800,755</u>	<u>42,827,568</u>
Total Liabilities and Partners' Equity	<u><u>\$ 42,076,628</u></u>	<u><u>\$ 42,847,595</u></u>

See accompanying notes to financial statements.

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Operations

Three Months Ended March 31, 2006 (unaudited), and
Period from December 6, 2005 (Date of Inception) to December 31, 2005

	<u>March 31, 2006</u> (Unaudited)	<u>December 31, 2005</u>
Revenues	\$ 420,087	\$ -
Cost and expenses:		
Exploratory dry hole costs	1,251,337	-
Production and operating costs	69,656	-
Management fee	-	536,033
Depreciation, depletion and amortization	124,896	-
Accretion of asset retirement obligations	2,275	-
Direct costs	500	20,027
Total cost and expenses	<u>1,448,664</u>	<u>556,060</u>
Loss from operations	(1,028,577)	-
Oil and gas price risk management gain, net	1,764	-
Net loss	<u>\$ (1,026,813)</u>	<u>\$ (556,060)</u>
Net loss – Managing General Partner	<u>\$ (308,044)</u>	<u>\$ (6,008)</u>
Net loss – Investor Partners	<u>\$ (718,769)</u>	<u>\$ (550,052)</u>
Net loss per Investor Partner unit	<u>\$ (402)</u>	<u>\$ (308)</u>
Investor Partner units outstanding	<u>1,787</u>	<u>1,787</u>

See accompanying notes to financial statements.

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Partners' Equity

Three Months Ended March 31, 2006 (unaudited), and
Period from December 6, 2005 (Date of Inception) to December 31, 2005

	Investor Partners	Managing General Partner	Total
Partners' initial contributions	\$ 35,735,509	\$ 11,231,670	\$ 46,967,179
Syndication costs	(3,583,551)	-	(3,583,551)
Net loss	(550,052)	(6,008)	(556,060)
Balance, December 31, 2005	31,601,906	11,225,662	42,827,568
Net loss (unaudited)	(718,769)	(308,044)	(1,026,813)
Balance, March 31, 2006 (unaudited)	<u>\$ 30,883,137</u>	<u>\$ 10,917,618</u>	<u>\$ 41,800,755</u>

See accompanying notes to financial statements.

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Cash Flows

Three Months Ended March 31, 2006 (unaudited), and
Period from December 6, 2005 (Date of Inception) to December 31, 2005

	March 31, 2006 (Unaudited)	December 31, 2005
Cash flows from operating activities:		
Net loss	\$ (1,026,813)	\$ (556,060)
Adjustments to net loss to reconcile to cash used in operating activities:		
Depreciation, depletion and amortization	124,896	-
Exploratory dry hole costs	1,251,337	-
Accretion of asset retirement obligations	2,275	-
Changes in operating assets and liabilities:		
Increase in accounts receivable - oil and gas sales	(423,304)	-
Unrealized loss on derivative transactions	1,953	-
Increase in accrued expenses	69,656	20,027
Net cash used in operating activities	<u>-</u>	<u>(536,033)</u>
Cash flows from investing activities:		
Expenditures for oil and gas properties	<u>-</u>	<u>(42,847,595)</u>
Net cash used in investing activities	<u>-</u>	<u>(42,847,595)</u>
Cash flows from financing activities:		
Investor Partners' contributions	-	35,735,509
Managing General Partner contribution	-	11,231,670
Syndication costs paid	<u>-</u>	<u>(3,583,551)</u>
Net cash provided by financing activities	<u>-</u>	<u>43,383,628</u>
Net change in cash	-	-
Cash at beginning of period	<u>-</u>	<u>-</u>
Cash at end of period	<u>\$ -</u>	<u>\$ -</u>

See accompanying notes to financial statements.

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

(1) Organization

The Rockies Region Private Limited Partnership (the "Partnership") was organized as a limited partnership on December 6, 2005, in accordance with the laws of the State of West Virginia for the purpose of engaging in the exploration and development of oil and gas properties.

Purchasers of partnership units subscribed to and fully paid for 41.5 units of limited partner interests and 1,745.2755 units of additional general partner interests at \$20,000 per unit. Petroleum Development Corporation ("PDC") has been designated the Managing General Partner of the Partnership. Although costs, revenues and cash distributions allocable to the limited and additional general partners (collectively, the "Investor Partners") are shared pro rata based upon the amount of their subscriptions, including the Managing General Partner to the extent of its capital contributions, there are significant differences in the federal income tax effects and liability associated with these different types of units in the Partnership.

Upon completion of the drilling phase of the Partnership's wells, all additional general partners units are to be converted into units of limited partner interests and thereafter become limited partners of the Partnership.

In accordance with the terms of the Limited Partnership Agreement (the "Agreement"), the Managing General Partner manages all activities of the Partnership and acts as the intermediary for substantially all Partnership transactions.

(2) Summary of Significant Accounting Policies

The unaudited interim financial statements as of and for the three months ended March 31, 2006, have been prepared from the Partnership's records using the same policies and procedures as the Partnership's December 31, 2005, audited financial statements. The interim financial statements do not include all disclosures required by U.S. generally accepted accounting principles, since Regulation S-K allows certain information and footnote disclosures that would typically be required in annual financial statements to be condensed or omitted. However, management believes that the interim financial statements reflect all the normal recurring adjustments necessary for a fair presentation, in all material respects, of the results of operations for the periods presented. These interim results are not necessarily indicative of the results to be expected for the year ending December 31, 2006.

The financial statements include only those assets, liabilities and results of operations of the partners which relate to the business of the Partnership. The statements do not include any assets, liabilities, revenues or expenses attributable to any of the partners' other activities.

Oil and Gas Properties

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

In periods prior to receiving a reserve report from an independent petroleum engineer the Partnership relies on the engineers and professionals of its Managing General Partner to provide reserve estimates used to calculate its depreciation and depletion. The Managing General Partner is staffed with experienced petroleum engineers and other professionals who utilize similar methods to estimate reserves as those used by an independent petroleum engineer. The Managing General Partner's engineers consider, along with other data, available geological, geophysical, production and economic data for each reservoir. Data is obtained internally through

ROCKIES REGION PRIVATE LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

the Managing General Partner's long history and experience in preparing such estimates, and when available, externally from available public records. Revisions subsequent to the date of estimate may be necessary as results of drilling, testing and production indicate a revision is appropriate. While the reserve estimates prepared by the Managing General Partner may differ from those prepared by other engineers, its estimation of proved reserves is based on the requirement of reasonable certainty.

Exploratory well drilling costs are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Partnership is making sufficient progress assessing its reserves and its economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of financial statements, the costs are expensed to exploratory dry hole costs. If a final determination about the productive status of a well is unable to be made prior to issuance of the financial statements, the well is classified as "Suspended Well Costs" until there is sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. When a final determination of a well's productive status is made, the well is removed from the suspended well status and the proper accounting treatment is recorded. The determination of an exploratory well's ability to produce is made within one year from the completion of drilling activities.

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

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

Revenue Recognition

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 marketed by an affiliate of the Managing General Partner under contracts on behalf of the Partnership with terms ranging from one month up to the life of the well. Virtually all of the 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 Partnership's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Partnership believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Managing General Partner currently uses the "net-back" method of accounting for transportation arrangements of natural gas sales. The Managing General Partner 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 the Managing General Partner's customers and reflected in the wellhead price.

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Sales of crude oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered from storage tanks at well locations to a purchaser, collection of revenue from the sale is reasonably assured and the sales price is determinable. The Partnership does not refine any of its oil production. The Partnership's crude oil production is sold to purchasers under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry. The Partnership currently sells its oil primarily to one customer and its natural gas primarily to two customers.

Asset Retirement Obligations

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

Derivative Financial Instruments

The Partnership uses derivative financial instruments as a way to manage exposure to commodity prices. The Partnership accounts for derivative financial instruments in accordance with FAS Statement No. 133 "Accounting for Derivative Instruments and Certain Hedging Activities" as amended." Through March 31, 2006, none of the derivative contracts qualified for hedge accounting under the terms of FAS No. 133." Accordingly, the derivative instruments are recorded as an asset or liability on the balance sheet at fair value and the change in the fair value is recorded in "oil and gas price risk management loss (gain), net." Because derivative arrangements are entered into by the Managing General Partner on behalf of the Partnership, they are reported on the balance sheet as a net short-term or long-term receivable due from or payable due to the Managing General Partner.

The measurement of fair value is based on actively quoted market prices, if available. Otherwise, the Managing General Partner 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 Managing General Partner.

By using derivative financial instruments to manage exposures to changes in commodity prices, the Partnership exposes itself to credit 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 Managing General Partner, which in turn owes the Partnership. The Managing General Partner minimizes this credit risk by entering into transactions with high-quality counterparties.

Income Taxes

Since the taxable income or loss of the Partnership is reported in the separate tax returns of the partners, no provision has been made for income taxes on the Partnership's books.

Use of Estimates

The Partnership 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 accounting principles generally accepted in the United States. Actual results could differ from those estimates. Estimates that are particularly significant to the financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties, which are used in assessing impairment of long-lived assets.

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(3) Transactions with Managing General Partner and Affiliates

The Managing General Partner and its wholly-owned subsidiaries, Riley Natural Gas and PDC Securities Incorporated, are regularly reimbursed for operating expenses and receive fees for services as provided for in the Partnership Agreement. The following table presents reimbursements and service fees paid by the Partnership to PDC or its affiliates for the period from December 6, 2005 (date of inception) to December 31, 2005.

	Period from December 6, 2005 (Date of Inception) <u>to December 31, 2005</u>
Wells in progress	\$ 315,048
Prepayment of drilling and completion costs	42,532,187
Syndication costs *	3,583,551
Management fee	536,033
Direct costs	20,027

* Consists of organization and offering costs, including costs of organizing and selling the offering (including total underwriting and brokerage discounts and commissions), expenses for printing, mailing, salaries of employees while engaged in sales activity, charges of transfer agents, registrars, trustees, escrow holders, depositories, engineers and other experts, expenses of qualification of the sale of the securities under federal and state law, including accountants' and attorneys' fees and other front end fees.

The table below presents the transactions with the Managing General Partner as of and for the three months ended March 31, 2006. (Unaudited)

As of March 31, 2006:	
Lease, drilling and completion costs incurred	\$ 26,931,078
Prepayment for development of oil and gas properties	15,916,517
Three months ended March 31, 2006:	
Well operation fees	\$ 8,800

In addition, as the operator of the Partnership's wells, the Managing General Partner receives all proceeds from the sale of the oil and gas produced and pays for all costs incurred related to services, equipment and supplies from vendors for all well production and operating costs and other direct costs of the Partnership. Net revenue from oil and gas operations is generally distributed monthly to all partners based on their share of costs and revenues, however the Partnership retains the underlying credit risk related to the customer. No distributions were paid during the three months ended March 31, 2006. See "Note 4 – Allocation of Partners' Interests."

As described above in "Note 2 – Summary of Significant Accounting Policies", the Managing General Partner utilizes commodity-based derivative instruments, entered into on behalf of the Partnership, to manage a portion of the Partnership's exposure to price risk from oil and natural gas production.

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The following table summarizes the open derivative positions for the Partnership as of March 31, 2006. (Unaudited)

		Quantity	Weighted		
		Average			Fair
<u>Commodity</u>	<u>Type</u>	<u>Gas-Mmbtu</u>	<u>Price</u>		<u>Value</u>
		(a)			
Total Positions as of March 31, 2006:					
Natural Gas	Sale Option	15,352	\$ 5.57		\$ (305)
Natural Gas	Purchase Option	3,863	\$ 7.63		\$ (1,648)
Due to Managing General Partner - derivatives, total					\$ (1,953)
Positions maturing within 12 months following March 31, 2006:					
Natural Gas	Sale Option	11,489	\$ 5.60		\$ 627
Natural Gas	Purchase Option	3,863	\$ 7.63		\$ (1,648)
Due to Managing General Partner - derivatives, short-term					\$ (1,021)
(a) Mmbtu - one million British thermal units. One British thermal unit is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.					

As of March 31, 2006, the maximum term for the derivative positions listed above is 15 months.

(4) Allocation of Partners' Interests

The table below summarizes the participation of the Managing General Partner and the Investor Partners in the costs and revenues of the Partnership, taking into account the Managing General Partner's capital contribution, which is equal to a minimum of 31.4% of the Investor Partners' initial capital.

	Investor Partners(e)	Managing General Partner (e)
<u>Partnership Costs</u>		
Organization and Offering Costs (a)	0%	100%
Offering Costs - Broker-dealer Commissions and Expenses (a)	100%	0%
Management Fee (b)	100%	0%
Undeveloped Lease Costs	0%	100%
Tangible Well Costs and Gathering Line Costs	0%	100%
Intangible Drilling Costs (IDC)	100%	0%
Managing General Partner's Drilling Compensation	100%	0%
Operating Costs (c)	70%	30%
Direct Costs (d)	70%	30%
<u>Partnership Revenues (e)</u>		
Sale of Oil and Gas Production	70%	30%
Sale of Productive Properties	70%	30%
Sale of Equipment	70%	30%
Sale of Undeveloped Leases	70%	30%
Interest Income	70%	30%

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- (a) The Managing General Partner paid all legal, accounting, printing, and filing fees associated with the organization of the Partnership and the offering of units and is allocated 100% of these costs. The Investor Partners paid all dealer manager commissions, discounts, and due diligence reimbursements and is allocated 100% of these costs. However, any organization and offering costs in excess of 10.5% of subscriptions will be charged and allocated to the Managing General Partner.
- (b) Represents a one-time fee paid to the Managing General Partner on the day the Partnership is funded equal to 1-1/2% of total investor subscriptions.
- (c) Represents operating costs incurred after the completion of productive wells, including monthly per-well charges paid to the Managing General Partner.
- (d) The Managing General Partner receives monthly reimbursement from the Partnership for direct costs incurred by the Managing General Partner on behalf of the Partnership.
- (e) The Managing General Partner will contribute and/or pay for the Partnership's share of all leases, tangible drilling and completion costs, and gathering line costs, totaling not less than 30% of the well costs excluding the Managing General Partner's drilling compensation. If these costs exceed the required capital contribution, the Managing General Partner will increase its capital contribution. In that event, the Managing General Partner's share of all items of profit and loss during the production phase of operations and cash available for distribution would be modified to equal the percentage arrived at by dividing the Managing General Partner's capital contributions by the total well costs, excluding the Managing General Partner's drilling compensation. The Investor Partners' allocations of these items would be changed accordingly. The Investor Partners' portion of capital available for investment will pay the intangible drilling costs, including the Managing General Partner's drilling compensation of 14% of the total cost of the Partnership's wells. The entire capital contribution of the Investor Partners, after payment of brokerage commissions, due diligence reimbursement, and the management fee, will be utilized to pay for intangible drilling costs. If the capital contributions of the Investor Partners are insufficient to pay the intangible drilling costs, the Managing General Partner will pay the additional amount of these costs, and in these circumstances the sharing arrangements for intangible drilling costs and recapture of intangible drilling costs will be in proportion to the Investor Partners' and the Managing General Partner's respective payment of intangible drilling costs.

(5) Costs Relating to Oil and Gas Activities

The Partnership is engaged solely in oil and gas activities, all of which are located in the continental United States. Drilling operations began upon funding on December 30, 2005, with payments made for all planned drilling and completion costs for the Partnership made in December 2005. Costs capitalized for these activities at December 31, 2005, included \$315,408 for wells in progress and \$42,532,187 for prepayments for the exploration and development of oil and gas properties.

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Costs incurred by the Partnership in oil and gas property acquisition, exploration and development as of March 31, 2006, are presented below: (unaudited)

Acquisition of properties:	
Unproved properties	\$ 119,805
Proved properties	159,342
Development costs:	
Producing properties	7,699,275
Wells in progress (1)	17,883,281
Sub-total	<u>25,861,703</u>
Prepayments for development of oil and gas properties	15,916,517
Total Oil and Gas Properties	<u>\$ 41,778,220</u>

(1) Excludes \$236,854 in property acquisition cost shown above.

(6) Exploratory Dry Hole Costs (Unaudited)

The Anadarko #14-1 exploratory well in Wyoming was drilled during the first quarter of 2006 and has been determined to be a dry hole. At March 31, 2006, the cumulative exploratory dry hole cost of this exploratory well is \$1,251,337.

(7) Supplemental Reserve Information (Unaudited)

Proved oil and gas reserves of the Partnership were not estimated by an independent petroleum engineer at December 31, 2005, as no wells had been completed as of that date. The proved oil and gas reserves provided below were estimated by the engineers and professionals of the Partnership's Managing General Partner who utilize similar methods to estimate reserves as those used by an independent petroleum engineer. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices.

	<u>Oil (Bbls)</u>
Proved developed reserves:	
January 1, 2006	-
Revisions of previous estimates	-
New discoveries and extensions	573,000
Production	<u>(5,000)</u>
March 31, 2006	<u>568,000</u>

	<u>Gas (Mcf)</u>
Proved developed reserves:	
January 1, 2006	-
Revisions of previous estimates	-
New discoveries and extensions	12,316,000
Production	<u>(13,000)</u>
March 31, 2006	<u>12,303,000</u>

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(8) 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 Partnership 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 period-end prices of oil and gas relating to the Partnership proved reserves to the period-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.

	<u>As of March 31, 2006</u>
Future estimated cash flows	\$ 98,808,000
Future estimated production costs	(23,007,000)
Future estimated development costs	<u>(5,060,000)</u>
Future net cash flows	70,741,000
10% annual discount for estimated timing of cash flows	<u>(32,139,000)</u>
Standardized measure of discounted future estimated net cash flows	<u>\$38,602,000</u>

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.