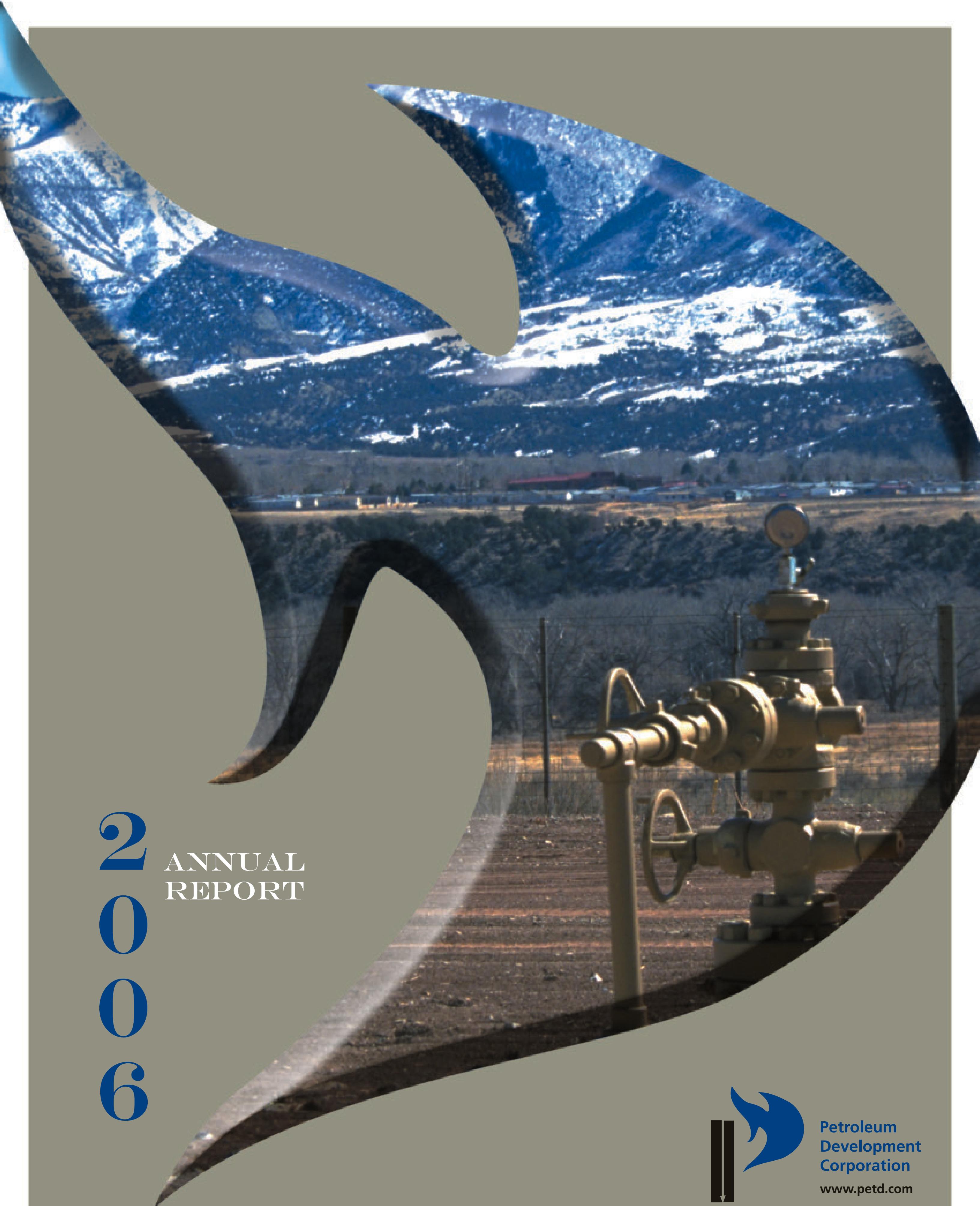
2006 ANNUAL REPORT



Petroleum Development Corporation

www.petd.com

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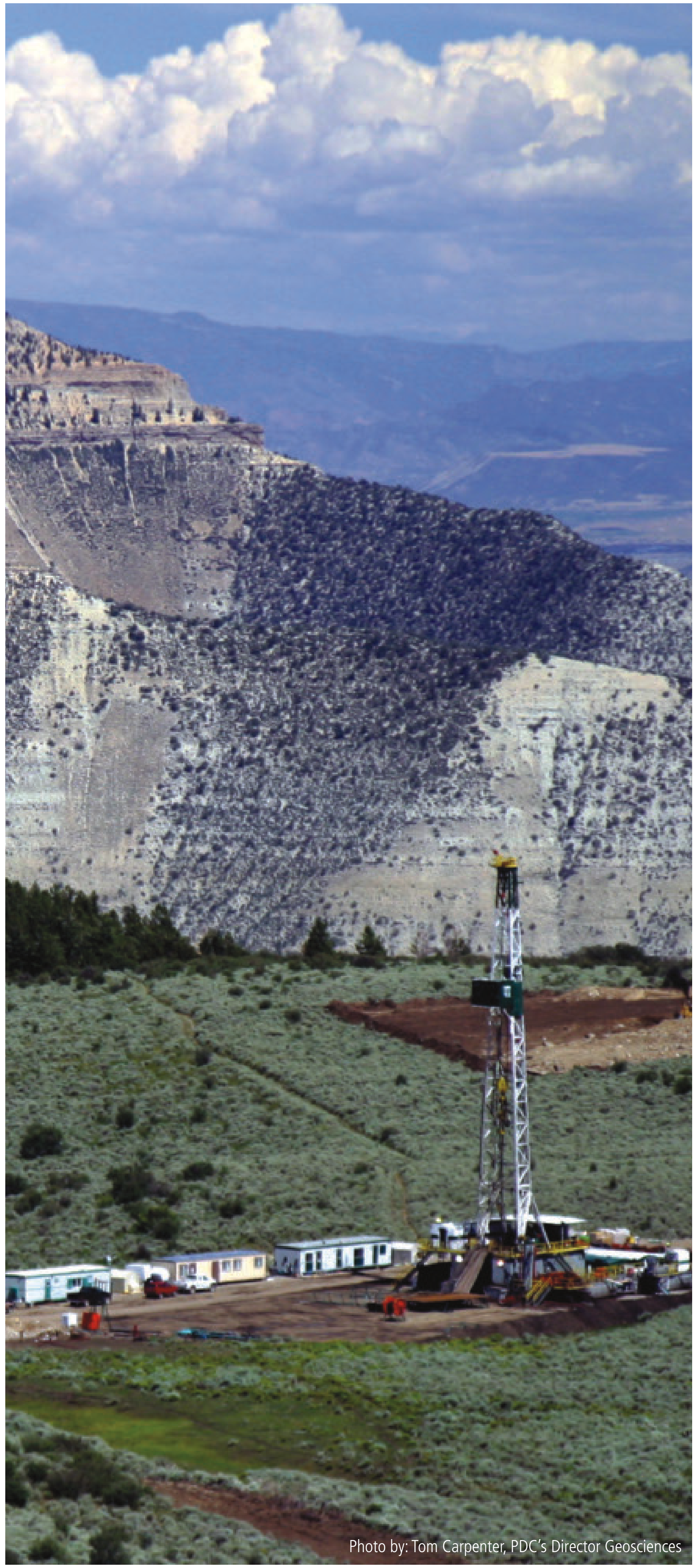


Photo by: Tom Carpenter, PDC's Director Geosciences

PROFILE

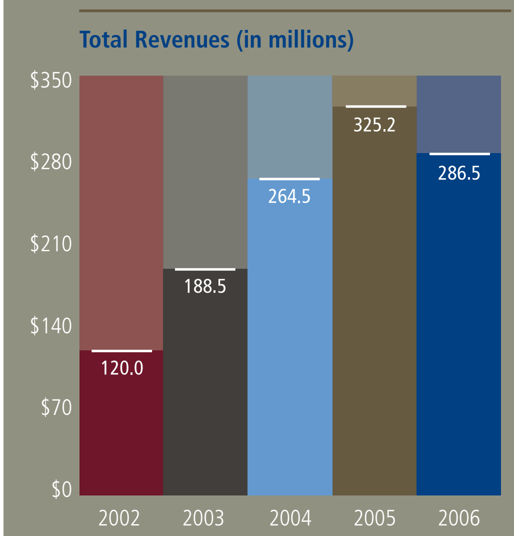
Petroleum Development Corporation (NASDAQ/GSM: PETD) (PDC) is a rapidly growing independent energy company engaged in the development, production and marketing of natural gas and oil. The Company's operations are focused in the Rocky Mountains with additional operations in the Appalachian Basin and Michigan. Approximately 78% of the Company's 2006 production was natural gas and 83% of total production was generated by the Rocky Mountain operating area. PDC also owns and operates a natural gas marketing company, Riley Natural Gas Company.

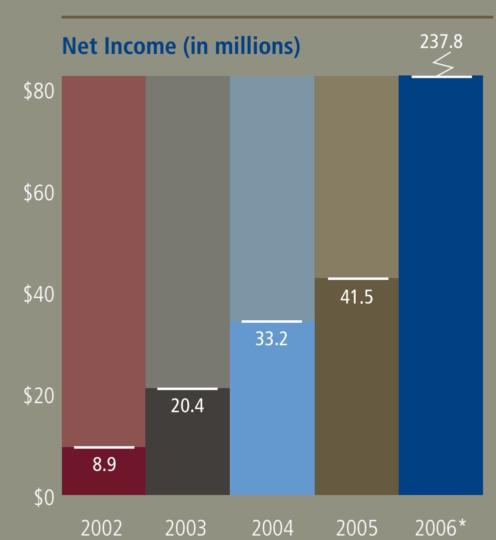
Sustained profitable growth is PDC's driving principle. The Company's success with acquisitions and development drilling in the Rocky Mountains has been the key to increasing reserves, production and shareholder value in recent years. We invite you to examine our five-year financial and operating data summaries beginning on page 13. PDC expects to continue delivering exceptional operating and financial performance in 2007 and beyond by combining drill-bit growth with carefully evaluated core-area acquisitions. The addition of an active exploratory program also provides significant upside potential to enhance prospects for continuing growth. To address new and expanding opportunities, PDC has strengthened its technical, geological and operating expertise, as well as enhanced the strength and depth of its financial team.

2006 ACHIEVEMENTS

- Lease sale proceeds of $354 million
- Company repurchased 1.6 million shares (10% of outstanding)
- 97% development drilling success on 222 wells
- 8 productive exploratory wells
- Record production of 16.9 billion cubic feet equivalent (Bcfe), up 24% from 13.7 Bcfe in 2005
- Record proved reserves of 323 Bcfe, a 17.5% increase from 2005
- Record oil and gas sales of $115.2 million from Company well interests
- Record Adjusted Cash Flow* of $350.3 million
- Record sales from gas marketing of $131.3 million
- Record net income of $237.8 million, or $15.11 per fully diluted share

*See note on page 13 for definition





*includes $201 MM in after-tax gain from leasehold sale

Photo by: Tom Carpenter, PDC's Director Geosciences

PRESIDENT'S LETTER TO SHAREHOLDERS

Last year was unequivocally a landmark year for our Company. We achieved record results in 2006 and further strengthened the foundation for what we believe will be remarkable advances in 2007 and beyond. This will be accomplished through a series of property transactions, reserve and production growth and organizational development.

HIGHLIGHTS

It would be difficult to begin a 2006 re-cap with anything other than the story of the Piceance Basin lease sale to Marathon Oil Corporation. The transaction, the largest in our 37-year history, involved the sale of 8,700 undeveloped acres, comprised of a portion of two of our leases in the area, for $354 million. By converting the tracts into cash, we greatly accelerated our near-term value creation, while retaining development opportunities to support continuing growth over the next few years. We retained approximately 475 undeveloped locations, on 10-acre spacing, to support our Piceance Basin drilling activity at or above our current level for approximately five to 10 years. In addition, we have improved our drilling and completion practices, increasing per-well estimated ultimate recoveries in the Piceance, further enhancing the value of our remaining undeveloped leasehold.

While the Piceance sale was truly a landmark transaction for PDC, it is only part of the story. We posted a tremendous year, even without the Marathon transaction. Our production increased by 24% in 2006 compared to 2005, almost entirely organic, drill bit growth from developing internally generated drilling opportunities. Our Rocky Mountain region continued as the centerpiece of our operations with successful development activities. Our Appalachian and Michigan operations contributed the same solid, profitable results that they have delivered time and time again. Both Riley Natural Gas Company and our Partnership activities also contributed to the positive operating results.

The key to our success in executing our business plan has been our personnel development. During the year, we implemented our Human Resources and Information Technology Departments, grew our employment base by 28%, and continued our highly effective Strategic Planning Process. Additionally, we completed our new corporate headquarters in Bridgeport, and moved into our new facilities in Denver.

LOOKING FORWARD

The Piceance Basin leasehold sale helped position the Company for strong production and reserve growth in 2007 and beyond. By monetizing a portion of our Piceance acreage position, we were able to fund the acquisition of other assets that we can develop more readily than the

Piceance properties. Most of the acquired properties are located in existing PDC operating areas, mainly the Denver-Julesberg (DJ) Basin. This allows PDC to leverage its expertise to quickly develop the properties, creating more near-term shareholder value. Our 2007 plans include increased development activity in Wattenberg Field and our Northeast Colorado (NECO) area, while maintaining our pace in the Piceance Basin.

We plan to drill an estimated 400 wells during 2007 as part of our $200 million capital expenditure budget. The drilling activity will be a Company record and is almost twice the number of wells as our past record. We have the technical staff and personnel in-house who are capable and ready to meet the challenge of a record drilling pace and CAPEX budget.

Increased activity generally results in increased production and cash flow, depending upon drilling success and commodity prices. We anticipate 2007 production of about 28 Bcfe, a 65% increase over 2006 production, from our aggressive development program and contributions from our acquisitions. Further, we expect to complete the year with a strong balance sheet, and are prepared to continue aggressive development in 2008 and beyond.

To support the additional activity and growth going forward, we are adding substantially to our organizational capabilities in all areas of the Company. Our key additions to geology, geophysics, engineering, finance, accounting and management enhance our ability to organize and manage the drilling and operation of current and new properties into the future. With the addition of Richard McCullough, our new Chief Financial Officer, we are continuing to implement best-practice internal controls, financial reporting and corporate governance, all of which are essential to our Company's long-term success.

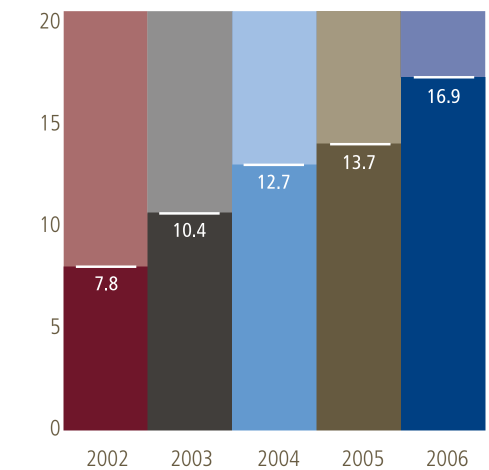
We have the people and the resources to continue to deliver outstanding results to our shareholders in 2007 and the coming years. Equally important, we are dedicated to fully optimizing and developing the capabilities and talent of the employees of Petroleum Development Corporation.

Respectfully submitted,

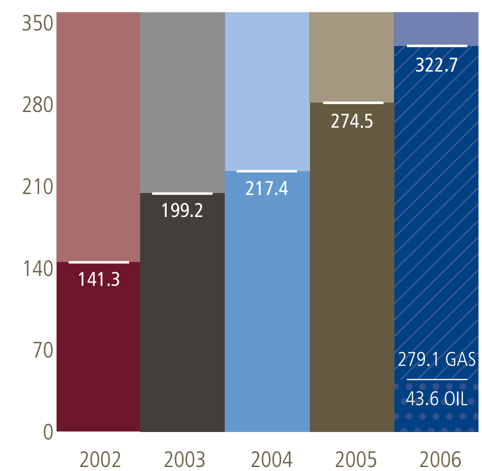
Thomas E. Riley
President

July 31, 2007

Production (BCFE)



Reserves (BCFE)



Wells Operated/Net Wells Owned

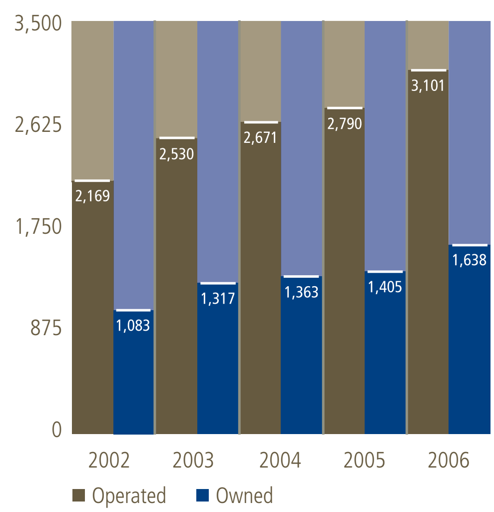


Photo by: Tom Carpenter, PDC's Director Geosciences

CHAIRMAN'S LETTER TO SHAREHOLDERS

Over the past 24 years I have proudly served PDC, first as its President, and more recently as CEO and Chairman. The commitment and dedication of PDC's outstanding employees has challenged me through my tenure with the Company to perform at the same high level. I have also had the privilege of serving with a succession of outstanding Directors who have helped guide the Company to remarkable success through often difficult and challenging times. I consider myself honored and blessed in the time I have spent working with both groups.

I have decided that it is time for me to step aside and let others lead the Company into the future. It is not a decision I have made easily or without regrets. My wife and family have supported my high level of commitment to PDC, frequently at their cost, for many years. It is time now for me to put them first. I also have other personal interests, largely set aside in the past, that I want to pursue more fully.

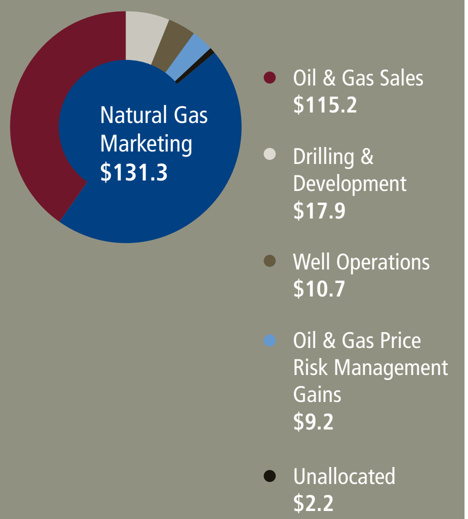
To assure that the Company has the best possible leadership and to allow time for a smooth transition, I will continue to serve in my present position through 2008. The Board has developed and is executing a carefully planned search and succession process. The person selected to fill the CEO position will have an outstanding organization, a talented management team, and a strong, committed Board to help continue the success of the Company. I believe Petroleum Development Corporation has a great future, and I thank you for your continued support.

Sincerely,

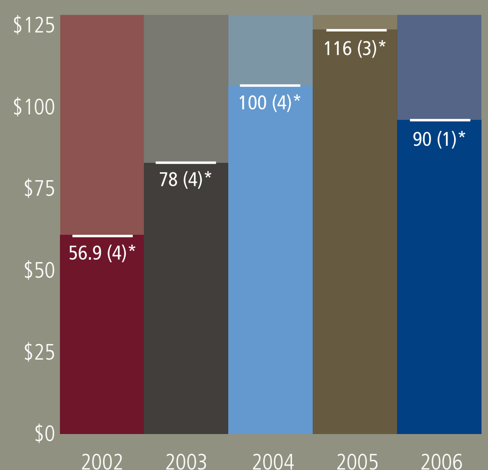
Steven R. Williams
Chairman and CEO

July 31, 2007

2006 Revenue Breakout (in millions)



Partnership Sales (in millions)



*( ) = number of partnerships closed

SALE AND ACQUISITIONS

In July 2006, we sold 8,700 acres of undeveloped leasehold interests to Marathon Oil Corporation for $354 million, retaining approximately 475 undeveloped locations, based on 10-acre field spacing, for future development by PDC. The retained leasehold provides several years of development drilling, while the cash from the sale was used to acquire other properties with more immediate development potential. Of the reinvested funds, $191.5 million was used to acquire producing properties and undeveloped drilling locations, which qualified as tax-deferred "Like-Kind" exchanges.

The first transaction subsequent to the lease sale in December 2006 was the purchase of 9.1 million shares of the outstanding stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The total acquisition cost of $18.6 million for 100% of Unioil's outstanding common stock did not qualify for Like-Kind exchange treatment.

Three separate properties were acquired in Like-Kind exchanges in January 2007. The largest acquisition included 144 producing oil and gas wells with approximately 25.5 Bcfe of proved developed reserves and 8,160 acres of complementary, undeveloped leasehold, formerly controlled by EXCO Resources. PDC operates the acquired assets, which are primarily located in the Wattenberg Field in close proximity to PDC's existing operations.

Also as part of the Like-Kind acquisitions, the Company purchased the remaining working interests in 718 wells in 44 Company-sponsored partnerships. PDC will continue to act as operator of these properties. The acquired properties are located primarily in the Appalachian Basin and Michigan.

The final component of the Like-Kind exchange transactions was the acquisition of undeveloped leaseholds in Erath County, Texas for $1.8 million. The target formation for initial development is the Barnett Shale formation. All of the Like-Kind transactions were completed in the first quarter of 2007.

After the expiration of the Like-Kind exchange period, PDC acquired from an unrelated party 28 producing wells and associated undeveloped acreage located in Colorado's Wattenberg Field for a purchase price of $11.8 million. The acquisition includes daily production of approximately 668 Mcfe for the interests acquired and at least 100 undeveloped drilling locations, with estimated net proved reserves of 19.1 Bcfe and probable reserves of 7.5 Bcfe.

AREAS OF OPERATIONS

Petroleum Development Corporation conducts oil and natural gas operations in three regions: the Rocky Mountains, the Appalachian Basin, and Michigan. Combined, the operations include approximately 3,100 gross wells with equivalent gross proved reserves of 719 Bcfe. On average, the Company owns about 51.4% of the working interest in the wells, and our net reserves total 323 Bcfe, after allowing for royalty and outside working interest owners. The Company has drilled most of the wells in which it owns an interest and currently operates virtually all of the wells.

ROCKY MOUNTAIN REGION

We have been capitalizing on select opportunities in our Rocky Mountain region to generate rapid reserve and production growth. In 2006, these opportunities included development well drilling, recompleting existing wells and a limited amount of exploratory well drilling. We drilled 222 successful development wells and eight successful exploratory wells during the period. We continued our successful Codell Formation recompletion program in the Wattenberg Field. We also began completing Niobrara behind-pipe pay in existing wells.

To date, we have recompleted more than 180 wells with almost universally good results, including 43 wells in 2006. During the year, we completed a total of 23 Niobrara zones with results comparable to, if not better than, our Codell recompletions.

Also during 2006, we continued adding to the Company's proved reserves and production through infill and step-out drilling on our properties in northeast Colorado. We drilled a total of 44 wells in the area during 2006, of which 41 were successful. The new wells were largely located on new structural features identified through the use of 3-D seismic that PDC ran and evaluated in 2006.

Since 2001,
we have increased
our production at a
compound annual rate
of 17% per year,
a record not matched
by many of our peers

DJ Basin, the NECO area

Yuma & Washington Counties, Colorado and Cheyenne County, Kansas

In 2003, PDC purchased a majority interest in 260 wells in Washington and Yuma counties in the eastern part of the DJ Basin and across the state border in Kansas. In 2004 and 2005, PDC began an infill development drilling program in Beecher Island and Republican Fields. In 2006, PDC began the next phase of development in the project area, initiating a seismic and acreage acquisition program, expanding the scope of the project to encompass 30,000 undeveloped acres and eight defined structures suitable for drilling and testing. Leveraging the success of both infill and exploratory drilling in the area, the Company has approximately 100 PUD locations in the area and has identified additional structures on seismic with the potential to add several hundred locations to its development inventory.

The NECO Area Profile

2006 Activity

- Drilled 44 infill wells, three dry holes
- Increased acreage position
- Developed new prospects for additional drilling

2006 NECO Reserves	**Gas (MMcf)**	**Oil (MBbl)**
Proved Developed	31,835	0
Proved Undeveloped	22,140	0

2007 Plans

- Drill 141 wells, PDC 100% WI
- 31 Bcfe forecast to be added by drilling
- 4.5 Bcfe net production anticipated for 2007
- Acquire 50-square-miles of additional 3D seismic
- Seek additional acquisition opportunities and undeveloped acreage
- Identify additional new prospect areas for exploratory testing

During 2006, PDC moved into a new office in downtown Denver. The office serves as our Rocky Mountain Region operations base and houses engineering, geology, land, and other essential functions. Our Rocky Mountain operations focus on Wattenberg Field and the NECO area in the DJ Basin, and Grand Valley Field in the Piceance Basin. The Denver headquarters also oversees operations in the Bakken Shale and in the Nesson Formation in western North Dakota and will oversee at least the initial operations in the Barnett Shale in Texas. We will continue to concentrate our 2007 development drilling activity in the Rocky Mountain prospect areas, as we assess our position and formulate a strategy for our Barnett Shale acreage.

The Company participated in the drilling of nine gross (3.3 net) exploratory wells during 2006. Located in North Dakota in PDC's Bakken and Nesson project areas, eight of the nine wells were successful. We are continuing the exploratory program in 2007 and have several additional wells planned in the Rockies, including additional wells in the Bakken Shale and the Nesson Formation.

DENVER BASIN / WATTENBERG FIELD

Wattenberg Field, Weld County, Colorado

PDC continued to grow and expand its Wattenberg Field operations in 2006, as the Company has successfully done year-after-year since its entry into the area in late 1999. During 2006, we drilled 120 successful new wells, ending the year with 916 Company-operated wells. Wattenberg Field continues to play a major role in our current and future drilling plans. We expect to drill another 150 or more wells in the field during 2007. Most new wells will target development of gas and oil reserves in the Codell and Niobrara formations. Additional limited development opportunities exist in the deeper J-Sand Formation.

PDC's Codell recompletion program, focused on wells acquired several years ago, is an example of how we can unlock and maximize the value of existing production with additional investment. Recompleting Codell wells achieves material increases in production and ultimate reserve levels, generally after five or more years of production. We continued the successful recompletion program in 2006 with 43 additional recompletions and plan to continue the program in 2007 with about 164 planned recompletions. We will continue to recomplete wells drilled by the Company as production volumes and economic conditions dictate, but other exciting opportunities to enhance the value of existing Company assets are emerging.

Building on the success and knowledge gained from the Codell program, PDC and other operators believe that a similar opportunity of potentially greater value exists in the shallower Niobrara Formation. Many of our existing wells have behind-pipe Niobrara potential or, if producing from the Niobrara, could be recompleted to increase the production. PDC and other operators in the area have made successful initial completions or recompletions in this zone using new completion designs, leveraging knowledge from the Codell program. PDC successfully recompleted 23 wells in the Niobrara in 2006, with the hopes of adding another significant multi-year development opportunity in the area. Limited initial results indicate that the economics of the Niobrara recompletion program potentially will surpass those of the Codell program.

Wattenberg Field Profile

- Infill development drilling
- Production targets ranging from about 6,500' to 8,500'
- Primary targets are Codell, Niobrara and J-Sand
- Several hundred or more development locations available
- PDC operates 916 Wattenberg Field wells
- Wells produce gas / oil mixture
- PDC retains 20% to 100% WI
- Added 50,000-acre farmout in the area in the first quarter of 2006
- Constitutes a majority of PDC's oil production

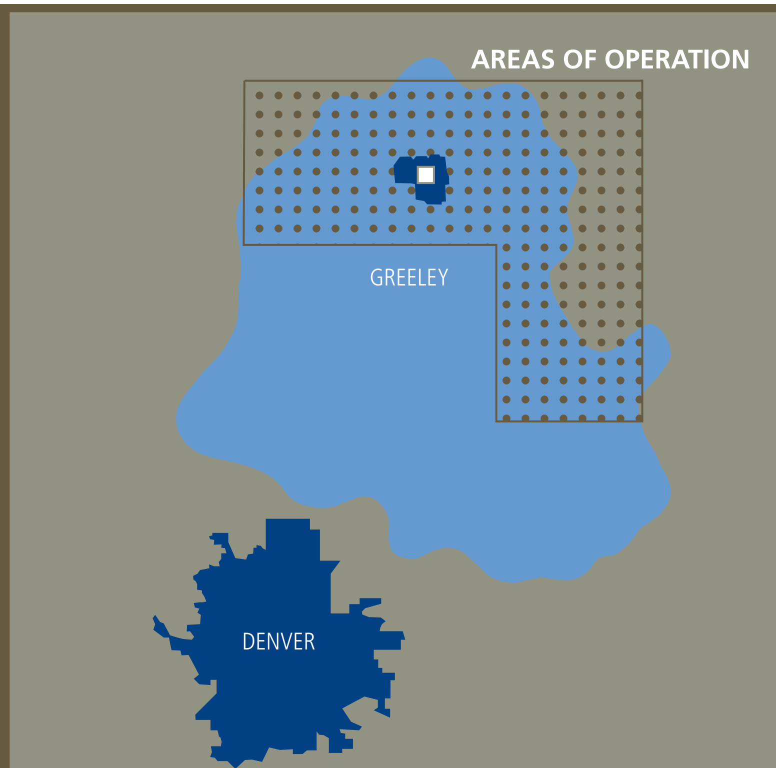
2006 Activity

- Drilled 123 wells (41 PDC and 82 Partnership)
- Recompleted 43 wells (20 Codell, 23 Niobrara)

2006 Wattenburg Reserves	Gas (MMcfe)	Oil (MBbl)
Proved Developed	34,103	4,123
Proved Undeveloped	17,947	2,223

2007 Plans

- Recomplete approximately 164 wells
- Drill approximately 150 gross wells, 100 net wells
- Increase production over 2006 levels attributable to development of assets acquired in January 2007
- Further define Niobrara recompletion potential and scope of Rule 318A infill drilling opportunities



PDC plans 38 net Piceance wells in 2007, adding approximately 46 Bcfe through the bit

PICEANCE BASIN / GRAND VALLEY FIELD

Garfield County, Colorado

The Grand Valley Field contributed greatly to the Company's success in 2006. In addition to the lease sale, PDC drilled 49 successful wells and received final determination from regulatory authorities granting 10-acre drilling density on all leases. PDC further refined its drilling and completion practices, began the Garden Gulch road project construction to improve access to the Company's undeveloped leasehold, and initiated an engineering review of Company-operated pipelines and facilities in the area.

Grand Valley Field Profile

- 470 potential development drilling locations on 10-acre spacing
- Well depths range from 6,000' to 10,000', depending upon surface location elevation and subsurface structure
- Production from Williams Fork and Cameo formations
- 2,000' gross producing interval includes 150' to 300' of net pay in numerous stacked-channel sandstone sequences
- 148 wells drilled through year-end 2006
- PDC operates and retains 20% to 100% WI

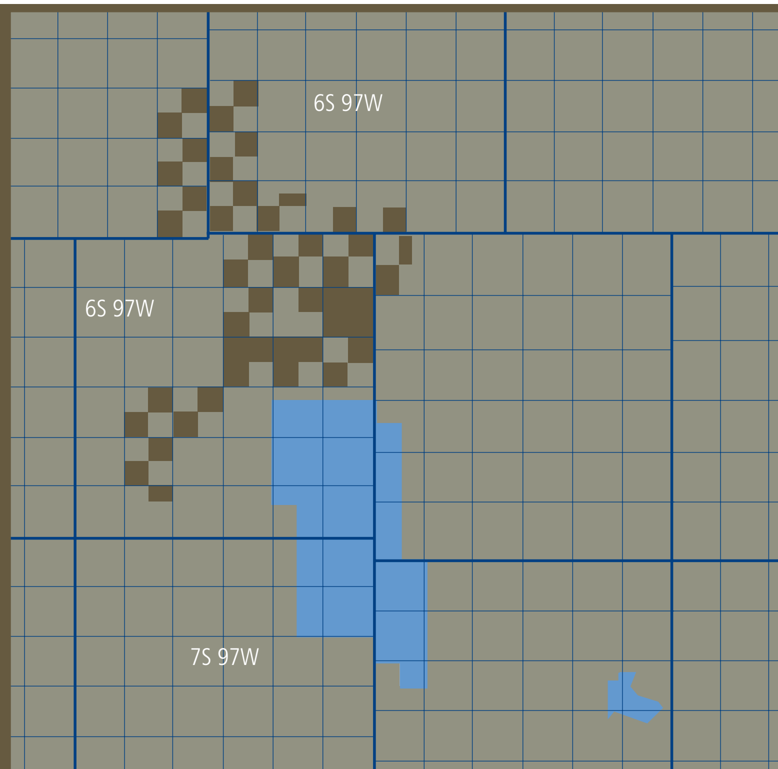
2006 Activity

- Drilled 49 wells (19 PDC, 30 Partnership)
- Initiated construction of Garden Gulch road, design of upgrade of pipeline and facilities

2006 Grand Valley Reserves	Gas (MMcfe)	Oil (MBbl)
Proved Developed	36,446	20
Proved Undeveloped	79,028	47

2007 Plans

- Drill 50 or more wells (30 PDC, 20 Partnership)
- Complete Garden Gulch road
- Upgrade Garden Gulch pipeline and compressor facility



APPALACHIAN BASIN

West Virginia & Pennsylvania

In 2006, PDC's Appalachian Basin properties contributed 8.6% of PDC's total production. At the end of 2006, we operated 1,365 wells in the Appalachian region. Our Appalachian region production was 1.46 Bcfe during 2006. We did not drill any wells in the region during 2006; however, we did complete a number of behind-pipe zones as regionally strong energy prices increased the attractiveness of the investment. We opened new producing zones in two wells during 2006. These low-cost completions have proven to be an effective use of investment dollars.

Most PDC wells in the region are Devonian and Mississippian-aged sandstones and siltstones. Low decline rates and productive lives exceeding 25 to 30 years are common in the Appalachian Basin, providing an excellent production base that can be accurately forecast due to a flat, per-well decline curve. Appalachian natural gas production typically sells at a premium to gas produced in most other areas because of its proximity to major northeast national gas markets.

During 2006, PDC's subsidiary Riley Natural Gas Company (RNG) was involved in wholesale and retail purchase and sale of natural gas primarily in the Appalachian area. RNG is a natural gas marketing company operating out of our Bridgeport headquarters. RNG purchases gas from more than 100 unaffiliated producers and resells the gas to end-users and other marketers. During 2006, RNG marketed 20.8 Bcf of natural gas for PDC and other producers. RNG also oversees our gas marketing activities in Michigan and the Rocky Mountain Region and manages our oil and natural gas hedging activities.

Appalachian Basin Profile

- PDC's original operating area
- 1,365 wells operated
- Production from long-lived Mississippian and Devonian tight formations
- Represents 8.6% of PDC's 2006 total production

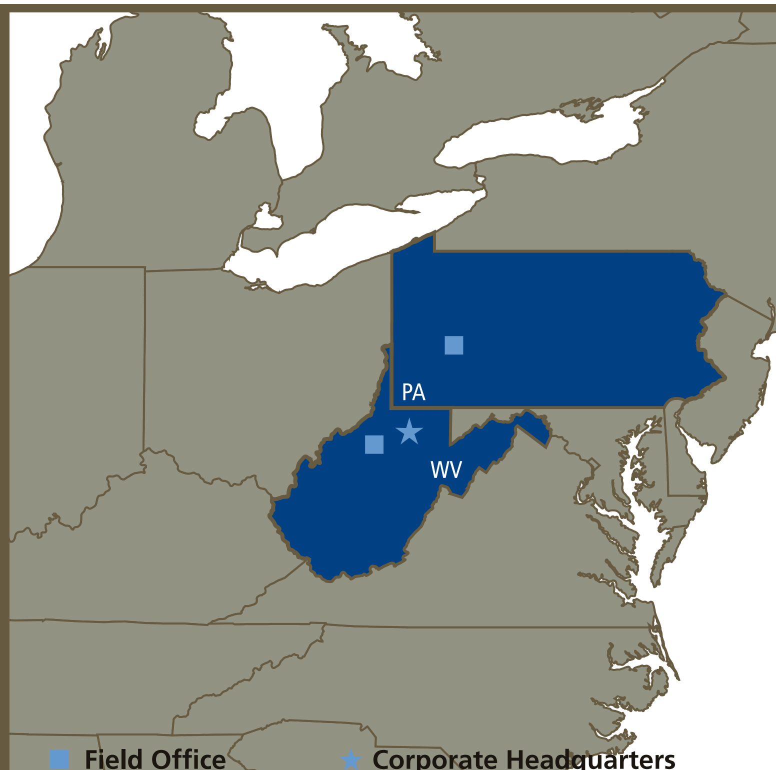
2006 Activity

- Completed behind-pipe reserves in two wells.

2006 Appalachian Reserves	Gas (MMcf)	Oil (MBbl)
Proved Developed	35,840	29

2007 Plans

- Complete behind-pipe reserves in 20 or more wells
- Drill up to 10 new wells



Michigan wells tend to enjoy long and predictable productive lives exceeding 20 years.

MICHIGAN BASIN

Antrim Shale, Michigan

At year-end 2006, PDC had 206 producing wells in Michigan. Production totaled 1.43 Bcfe during 2006. One new well was drilled in Michigan during the year. The Antrim Shale is generally located at shallower depths of approximately 1,000 feet in productive areas. Economic gas reserves are found in areas of fractured shale that are initially water-filled. Dewatering is necessary before gas production can begin from fractured shale. After dewatering is complete, production peaks, and the wells begin a long, gradual decline. As with Appalachian Basin wells, Michigan wells tend to enjoy long and predictable productive lives exceeding 20 years.

Michigan Basin Profile

- Fractured shale, dewatered and produced similar to coalbed methane wells
- PDC operates 206 wells
- Well depths of approximately 1,000'
- Represents about 8.4% of PDC's 2006 total production

2006 Activity

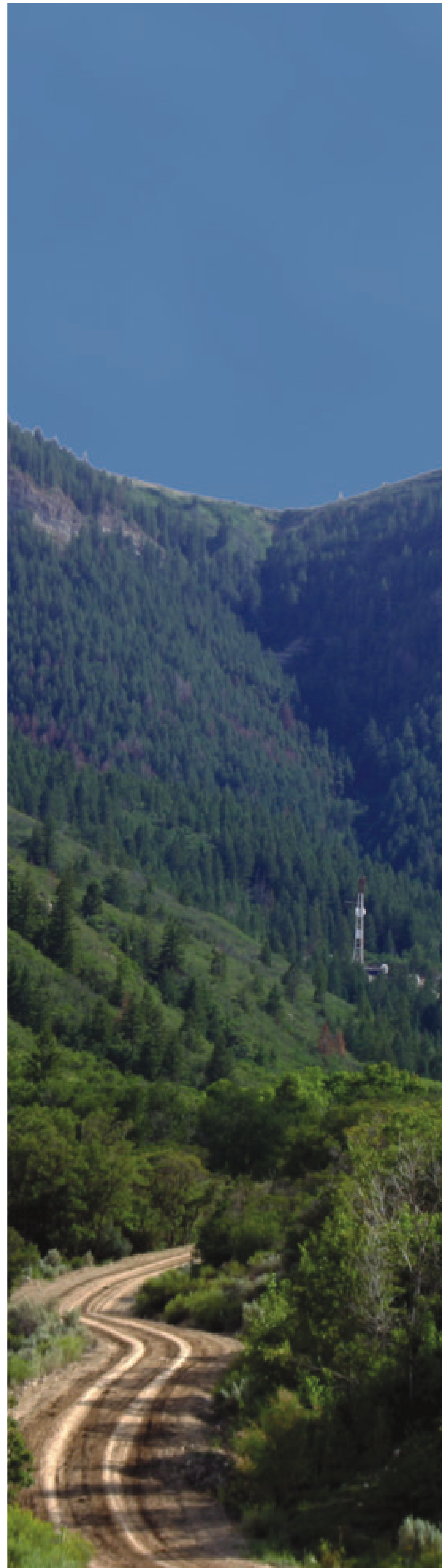
- Drilled one well

2006 Michigan Reserves

	Gas (MMcf)	Oil (MBbl)
Proved Developed	20,331	36
Proved Undeveloped	685	0

2007 Plans

- Pursue additional acreage and producing property acquisition opportunities
- Drill 1-2 wells



FINANCIAL SUMMARY: 5-YEAR FINANCIAL DATA

PDC's earnings and cash flow from operations increased to new Company records in 2006. The Piceance leasehold sale was the main factor for the record earnings and cash flow. Additionally, revenue and income from sales of oil and gas from Company interests in wells grew due to a 24% increase in natural gas production offset in part by lower average sales prices of natural gas. The average sales prices for our production in 2006 were $5.91 per Mcf of natural gas and $59.33 per barrel of crude oil. This compares to $7.29 per Mcf of gas and $50.56 per barrel of oil in 2005.

PDC set a new annual production record of 16.9 Bcfe in 2006, a 24% increase from 2005 production of 13.7 Bcfe. The Company drilled 216 successful new development wells in 2006 with only six dry holes and was successful on eight of nine total exploratory wells. Net earnings in 2006 were $237.8 million, or $15.11 per diluted share. Our Adjusted Cash Flow* from operations totaled $350.3 million in 2006. At year-end, long-term debt was $117 million.

* Adjusted Cash Flow - The United States Securities and Exchange Commission has disclosure requirements for public companies allowing references to Non-GAAP financial measures to be provided if the Company explains the relevance of the information. The Company must also reconcile the Non-GAAP financial measure to related GAAP information (see 5-year Selected Financial Data Table for reconciliation). "Adjusted Cash Flow" is a Non-GAAP financial measure provided by PDC in this annual report. Adjusted Cash Flow is net income before deferred income taxes, depreciation, depletion, and amortization, and unrealized derivative gains and losses. PDC believes Adjusted Cash Flow is relevant because it is a measure of cash available to fund the Company's capital expenditures and to service its debt. PDC also believes Adjusted Cash Flow is a valuable measure for estimating the value of the Company's operations.

5-YEAR SELECTED FINANCIAL DATA
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

	2002	2003	2004	2005	2006
Year Ended December 31,					
Revenues					
Oil and Gas Well Drilling Operations	$ 45,842	$ 57,510	$ 94,076	$ 99,963	$ 17,917
Gas Sales from Marketing Activities	43,537	73,132	94,627	121,104	131,325
Oil and Gas Sales	22,688	48,394	69,492	102,559	115,189
Well Operations and Pipeline Income	5,771	6,907	7,677	8,760	10,704
Oil and Gas Price Risk Management Gains (Losses), Net	(370)	(812)	(3,085)	(9,368)	9,147
Other	2,549	3,338	1,696	2,180	2,221
Total Revenues	120,017	188,469	264,483	325,198	286,503
Costs and Expenses (Excluding Depreciation, Depletion and Amortization)	94,091	137,912	192,796	246,304	198,966
Depreciation, Depletion and Amortization	12,602	15,313	18,156	21,116	33,735
Total Costs and Expenses	106,693	153,225	210,952	267,420	232,701
Gain on Sale of Leaseholds	—	—	—	7,669	328,000
Income from Operations	13,324	35,244	55,531	65,447	381,802
Interest Income	248	190	185	898	8,050
Interest Expense	1,505	816	238	217	2,443
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	12,067	34,618	53,478	66,128	387,409
Income Taxes	3,186	11,934	20,250	24,676	149,637
Cumulative Effect of Change in Accounting Principle Net of Income Taxes	—	2,271	—	—	—
Net Income	$ 8,881	$ 20,413	$ 33,228	$ 41,452	$ 237,772
Earning per Common Share:					
Basic	$ 0.56	$ 1.30	$ 2.05	$ 2.53	$ 15.18
Diluted	$ 0.55	$ 1.25	$ 2.00	$ 2.52	$ 15.11
Weighted Average Common Shares Outstanding (Diluted)	16,143	16,298	16,606	16,427	15,741
As of December 31,					
Total Current Assets	$ 74,427	$ 110,715	$ 119,762	$ 163,977	$ 271,014
Properties and Equipment, Net	123,826	174,682	203,512	265,926	394,217
Total Assets	198,838	294,004	329,453	444,361	884,287
Long-term Debt, Excluding Current Maturities	25,000	53,000	21,000	24,000	117,000
Total Shareholders' Equity	92,887	112,559	154,021	188,265	360,144
Working Capital	2,645	7,287	231	(16,763)	29,180
Long-term Debt to Shareholders' Equity	26.9%	47.1%	13.6%	12.7%	32.5%
Adjusted Cash Flow Reconciliation:					
Net Income	$ 8,881	$ 20,413	$ 33,228	$ 41,452	$ 237,772
Deferred Income Taxes	2,189	8,462	9,887	3,351	86,431
Depreciation, Depletion and Amortization	12,602	15,313	18,156	21,116	33,735
Unrealized Gains (Losses) on Derivative Transactions	(517)	1,110	(535)	(3,226)	7,620
Adjusted Cash Flow	24,189	43,078	61,806	69,145	350,318
EBITDA	$ 26,174	$ 48,475	$ 71,872	$ 87,461	$ 423,587

5-YEAR OPERATING DATA

Drilling success, increased production and higher reserves are the highlights of 2006 operating results. We drilled a total of 222 development wells in 2006, and all but six of them were completed as producing wells. We also had eight exploratory successes out of nine exploratory wells drilled. Production increased 24% and reserves increased 17.5% through a combination of drilling and well recompletions. PDC continues to be one of the most active drillers among small independents. We now operate over 3,100 wells in our three core areas.

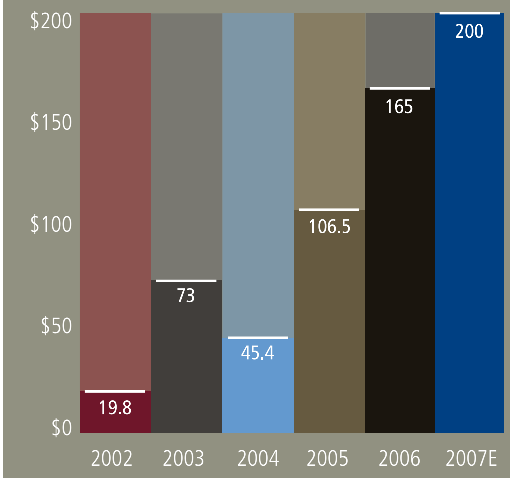
ESTIMATED OIL AND GAS RESERVES	2002	2003	2004	2005	2006
Proved Developed Reserves					
Natural Gas (MMcf)	94,847	134,936	146,152	155,354	158,978
Oil (MBbl)	1,849	2,889	3,190	3,860	4,629
Total (MMcfe)	105,941	152,270	165,292	178,514	186,752
Total Reserves					
Natural Gas (MMcf)	128,851	180,998	197,549	247,288	279,078
Oil (MBbl)	2,073	3,029	3,316	4,538	7,272
Total (MMcfe)	141,289	199,172	217,445	274,516	322,710
Percent Proved Developed	75%	76%	76%	65%	58%
SEC PV10 After Tax (000)	$98,469	$ 202,383	$229,428	$405,430	$215,662

OIL AND GAS OPERATIONS	2002	2003	2004	2005	2006
Production					
Natural Gas (MMcf)	6,462	8,712	10,372	11,031	13,161
Oil (MBbl)	227	289	381	439	631
Total (MMcfe)	7,824	10,446	12,658	13,665	16,949
Average Sales Price					
Natural Gas (per MMcf)	$ 2.65	$ 4.58	$ 5.30	$ 7.29	$ 5.91
Oil (per MBbl)	$ 24.41	$ 29.39	$ 38.00	$ 50.56	$ 59.33
Natural Gas Equivalents (per MMcfe)	$ 2.90	$ 4.63	$ 5.49	$ 7.51	$ 6.80
Average Production Costs (Lifting Cost) per Equivalent (Mcfe)	$ 0.76	$ 0.93	$ 1.12	$ 1.19	$ 1.23
Depreciation, Depletion and Amortization Costs (per Mcfe)	$ 1.61	$ 1.47	$ 1.43	$ 1.55	$ 1.99
Operating Margin Percentage (EBITDA/Total Revenues)	22%	26%	27%	27%	148%
Wells Operated	2,169	2,530	2,671	2,790	3,101
Net Wells Owned	1,083	1,317	1,363	1,405	1,594
Average Ownership in Operated Wells	50%	52%	51%	50%	51%

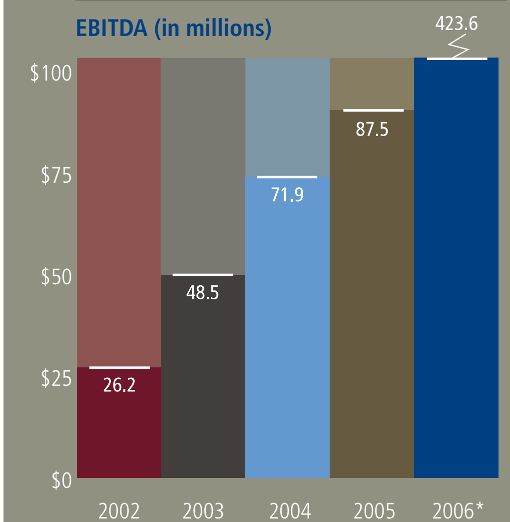
DRILLING	2002	2003	2004	2005	2006
Gross Wells					
Exploratory	0	1	1	8	9
Development	70	110	157	234	222
Dry Hole	0	1	4	7	7
Success Rate	100%	99%	97%	97%	97%
Production Replacement [1]	227%	654%	244%	518%	384%

[1] Represents change in total reserves divided by production

CAPEX (in millions)



EBITDA (in millions)



*includes $328 MM for leasehold sale in Q306

Photo by: Tom Carpenter, PDC's Director Geosciences

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

FORM 10-K

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

For the fiscal year ended December 31, 2006

or

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

Commission File Number 000-07246

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

Nevada	**95-2636730**
(State of incorporation)	**(I.R.S. Employer Identification No.)**

120 Genesis Boulevard
Bridgeport, West Virginia 26330
(Address of principal executive offices) (Zip Code)

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

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, par value $.01 per share	**NASDAQ Global Select Market**

Securities Registered Pursuant to Section 12(g) of the Act: None

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes_X_ No ___

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

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

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

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

As of April 30, 2007, 14,887,530 shares of the Registrant's Common Stock were issued and outstanding.

The aggregate market value of such shares held by non-affiliates of the Registrant on June 30, 2006, the last business day of the Registrant's most recently completed second quarter was $610,385,733 (based on the last traded price of $37.70).

DOCUMENTS INCORPORATED BY REFERENCE

None.

PETROLEUM DEVELOPMENT CORPORATION
INDEX TO REPORT ON FORM 10-K

GLOSSARY OF TERMS

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

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

Bcf - One billion cubic feet.

Bcfe - One billion cubic feet of natural gas equivalents.

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

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

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

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

Division order - A contract setting forth the interest of each owner of an oil and gas property, and serves as the basis on which the purchasing company pays each owner's respective share of the proceeds of the oil and gas purchased.

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

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

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

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

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

MBbls - One thousand barrels.

Mcf - One thousand cubic feet.

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

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

MMcf - One million cubic feet.

MMcfe - One million cubic feet of natural gas equivalents.

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

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

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

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

Oil - Crude oil or condensate.

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

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

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

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

Proved developed reserves - The combination of proved developed producing and proved developed non-producing reserves.

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

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

Recompletion - A recompletion occurs when the producer reenters a well to complete (i.e., perforate) a new formation from that in which a well has previously been completed.

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

SEC - The United States Securities and Exchange Commission.

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

Tcf - One trillion cubic feet.

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

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

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

PART I

ITEM 1: BUSINESS

Petroleum Development Corporation is an independent energy company engaged primarily in the development, production and marketing of natural gas and oil. Since it began oil and gas operations in 1969, the Company has grown primarily through drilling and development activities, the acquisition of producing natural gas and oil wells and the expansion of its natural gas marketing activities. As of December 31, 2006, the Company has interests in approximately 3,100 wells located in the Rocky Mountain Region, Appalachian Basin and Michigan with gross proved reserves of 719 billion cubic feet equivalent of natural gas (“Bcfe”, based on one barrel of oil equaling six thousand cubic feet equivalent of natural gas (“Mcfe”)) of which the Company's share is 323 Bcfe. The Company's share of production for the fourth quarter of 2006 averaged 52,000 Mcfe per day.

Unless the context otherwise requires, the terms "PDC" or "Company" refer to Petroleum Development Corporation, its subsidiaries and proportionately consolidated drilling partnerships, collectively. The Company’s corporate headquarters are located at 120 Genesis Boulevard, Bridgeport, West Virginia 26330 where the telephone number is (304) 842-3597.

Business Segments

The Company’s operations are divided into four segments for management and reporting purposes: (1) drilling and development, (2) natural gas marketing, (3) oil and gas sales and (4) well operations and pipeline income. See Note 17 to the consolidated financial statements.

Drilling and Development

The Company drills wells not only for itself, but also for its investor partners. When the Company drills wells for others it earns profit above the cost of the wells. Beginning with the last Company-sponsored partnership of 2005 (for which revenue generating activities did not commence until early 2006), partnership wells are drilled on a “cost-plus” basis, where the Company bills investors for the actual cost of the wells plus an agreed upon mark-up above the costs. Prior to that, most of the Company’s third-party drilling activities were conducted on a footage-based basis, where the Company drills the wells for a fixed price per foot drilled with additional chargeable items per the drilling agreement.

Since 1984, the Company has sponsored limited partnerships formed to engage in drilling operations. The Company typically purchases a 20% to 37% ownership working interest in these drilling limited partnerships. In 2006, the Company, through one private drilling partnership, raised approximately $90 million in investor subscriptions, making it one of the largest sponsors of oil and gas partnership programs in the United States, as it has been for the last several years. PDC’s working interest is 37% in the 2006 partnership. Through the partnerships, the Company has been able to expand its drilling opportunities, reduce its drilling risk through greater diversification, and share the costs of the infrastructure necessary to support such activities.

Natural Gas Marketing

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

Oil and Gas Sales

Revenue and expenses from the production and sale of oil and natural gas from the Company’s interests in oil and gas wells is reported in this segment. The Company has interests in approximately 3,100 wells ranging from a few percent to 100%. During 2006, approximately 9% of the Company’s production was generated by Appalachian Basin wells, 8% by Michigan Basin wells and 83% by Rocky Mountain Region wells. As of the end of 2006, the Company's total proved reserves were located as follows: Appalachian Basin (11%), Michigan (7%) and Rocky Mountain Region (82%). The majority of the Company's undeveloped acreage is in the Rocky Mountain Region and the Company's planned drilling for 2007 will be focused in that area. See Note 3 to the consolidated financial statements for disclosure of significant customers.

Well Operations and Pipeline Income

The Company operates approximately 95% of the wells in which it owns an interest. When the Company owns less than 100% of the working interest in a well, it charges the other owners a competitive fee for operating the well. These revenues and the associated costs are reflected in the Well Operations segment.

Areas of Operations

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

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

Business Strategy

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

Drill and Develop

Drilling developmental natural gas wells has been the mainstay of the Company's drilling program for a number of years. The Company drilled 231 wells in 2006, compared to 242 wells in 2005. In addition, the Company seeks to maximize the value of its existing wells through a program of well recompletions. The Company's management believes that it will be able to drill a substantial number of new wells on its current undeveloped leased properties. As of December 31, 2006, the Company had leases or other development rights to 200 undeveloped acres in the Michigan Basin, 12,800 undeveloped acres in the northern Appalachian Basin and 187,500 undeveloped acres in the Rocky Mountain Region. The Company also plans to recomplete about 164 Wattenberg Field wells (Colorado) during 2007.

To support future development activities the Company has conducted exploratory drilling in the past and will continue exploratory drilling plans in 2007. The goal of the exploration program is to develop several significant new areas for the Company to include in its future development drilling activity.

Acquire

The Company's acquisition efforts are focused on producing properties that fit well within existing operations or in areas where the Company is establishing new operations. Preferred properties have most of their value in producing wells, behind pipe reserves or high quality proved undeveloped locations. Acquisitions have historically offered economies in management and administration costs, and the Company's management believes that with its growing operations staff it can acquire and manage more producing wells without incurring substantial increases in its administrative costs. See Notes 2, 15 and 16 to Consolidated Financial Statements.

Diversify and Focus

With operations in the Rocky Mountains, Michigan and the Appalachian Basin, the Company has proven its ability to grow through operations in geographically diverse areas. While these areas provide geographic diversification, within each area, the Company has concentrated positions that lend themselves to effective development and operation. The Company plans to conduct the majority of its drilling activities in the Rocky Mountain Region during 2007, but will continue to seek additional opportunities for expansion in areas where the Company's experience and expertise can be applied successfully.

Manage Risk

The Company seeks opportunities to reduce the risks inherent in the oil and gas industry in a variety of ways. For a number of years, an integral part of the Company's strategy has been to concentrate on development drilling and geographical diversification to reduce risk levels associated with natural gas and oil drilling, production and markets. Development drilling is less risky than exploratory drilling and is likely to generate cash returns more quickly. Development drilling will remain the foundation of the Company's drilling activities in 2007. However, the Company's management believes the increasing cost of high quality development locations has made exploratory drilling relatively more attractive for future efforts. Exploratory wells have the potential of identifying new development opportunities at a significantly lower cost than the current cost of acquiring proven locations. While successful exploratory efforts could add to the Company's future drilling opportunities at favorable costs, under the successful efforts method of accounting, exploratory dry holes are expensed at the time it is recognized that they are unproductive. This could result in greater short-term expenses and a reduction in the near-term profitability of the Company.

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

Available Information Posted on the Company's Website

The Company files Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, registration statements and other items with the Securities and Exchange Commission ("SEC"). PDC provides free access to all of these SEC filings, as soon as reasonably practicable after filing, on its internet site located at www.petd.com. The Company will also make available to any shareholder, without charge, a copy of its Annual Report on Form 10-K as filed with the SEC. For a copy of the Company's Annual Report, or any other filings, please contact: Petroleum Development Corporation, Investor Relations and Communications Department, P.O. Box 26, Bridgeport, WV 26330, or call toll free (800) 624-3821.

In addition to the Company's SEC filings, other information, including the Company's press releases, current drilling program sales, Bylaws, Committee Charters, Code of Business Conduct and Ethics, Shareholder Communication Policy, Board Nomination Procedures and the Whistleblower and Qualified Legal Compliance Committee Hotline, is also available at the Company's internet site, www.petd.com.

The public may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxies, information statements and other information regarding issuers, like PDC, that file electronically with the SEC.

Natural Gas Industry Overview

Natural gas is one of the largest energy sources in the United States. The estimated 21.9 Tcf of natural gas consumed in 2006 represented approximately 22% of the total energy used in the United States. Natural gas is consumed in the United States as follows: 35% by industrial end-users as feedstock for products such as plastic and fertilizer or as the energy source for producing products such as glass; 21% and 14% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; 28% by utilities for the generation of electricity; and 2% for other users. (Source U.S. Energy Information Administration)

The Company's management believes that the market for natural gas will continue to grow in the future. Natural gas burns cleaner than most fossil fuels and produces less greenhouse gas per unit of energy released. Relative to other energy sources, natural gas usage and losses during transportation from source to destination are slight, averaging only about 2% of the natural gas energy. The delivery of natural gas is among the safest means of distributing energy to customers, as the natural gas transmission system is fixed and is located underground.

The deregulation of the natural gas industry and a favorable regulatory environment have resulted in end-users' ability to purchase natural gas on a competitive basis from a greater variety of sources. Increasing international demand for petroleum combined with supply constraints kept oil prices near record high levels throughout 2006. Continuing increases in world energy demand appear likely in 2007 and beyond. This makes natural gas more competitive in domestic markets as a replacement for oil and increases the value of domestic oil and natural gas reserves.

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

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

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

Operations

Exploration and Development Activities

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

Prospect Generation

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

On the basis of these models, the Company's land department obtains available natural gas and oil leaseholds, farmouts and other development rights in these prospective areas. In most cases to secure a lease, the Company pays a lease bonus and annual rental payments, converting, upon initiation of production, to a royalty. In addition, overriding royalty payments may be made to third parties in conjunction with the acquisition of drilling rights initially leased by others. As of December 31, 2006, the Company had leasehold rights to approximately 200,500 acres available for development. See "Properties--Oil and Natural Gas Leases."

Drilling Activities

When prospects have been identified, leased and all regulatory approvals obtained, the Company develops these properties by drilling wells. In 2006, the Company drilled a total of 222 development wells, which 216 wells were designated successful. As of December 31, 2006, 82 of the 216 successful wells were awaiting gas pipeline connection. As of April 30, 2007, 67 of the wells awaiting pipeline connection were connected and turned in line. Typically, the Company will act as driller-operator for these prospects, frequently selling interests in the wells to Company-sponsored partnerships and other entities that are interested in exploration or development of the prospects. The Company retains a working interest in each well it drills.

The Company also drilled nine exploratory wells in 2006, eight (including one pending determination as of December 31, 2006) were determined to be productive and one was determined to be dry. Costs related to the dry hole of $1.3 million were expensed in 2006. The Company plans to conduct additional exploratory drilling activities in 2007. See "Financing of Company Drilling and Development Activities" and "Drilling and Development Activities Conducted for Company Sponsored Partnerships" for additional discussion regarding the Company's drilling activities.

Much of the work associated with drilling, completing and connecting wells, including drilling, fracturing, logging and pipeline construction is performed under the Company's direction by subcontractors specializing in those operations, as is common in the industry. When judged advantageous, material and services used by the Company in the development process are acquired through competitive bidding by approved vendors. The Company also directly negotiates rates and costs for services and supplies when conditions indicate that such an approach is warranted.

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

	Development Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
2002	70	13.7	70	13.7	-	-
2003	110	28.5	110	28.5	-	-
2004	157	43.0	153	42.4	4	0.6
2005	234	103.4	232	102.0	2	1.4
2006	**222**	**134.4**	**216**	**129.8**	**6**	**4.6**
Total	793	323.0	781	316.4	12	6.6

	Exploratory Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
2002	-	-	-	-	-	-
2003	1	1.0	-	-	1	1.0
2004	1	1.0	-	-	1	1.0
2005	8	7.3	3	2.3	5	5.0
2006	**9**	**3.3**	**8**	**2.8**	**1**	**0.5**
Total	19	12.6	11	5.1	8	7.5

Financing of Company Drilling and Development Activities

The Company conducts development drilling activities for its own account and acts as operator for other owners. When conducting activities for its own account, the Company uses cash flow from operations and capital provided from its long term credit facility to fund its share of operations.

Drilling and Development Activities Conducted for Company Sponsored Partnerships

In addition to wells and interests in wells that it drills for itself, the Company also acts as operator for other oil and gas owners. Historically, these other owners have included individuals, corporations, partnerships formed by non-affiliated parties and other investors. Currently, the Company's drilling partners consist primarily of public and private partnerships sponsored by the Company. The Company contributes a cash investment to purchase an interest in the drilling and development activities and serves as the managing general partner for each partnership; accordingly, the Company is subject to substantial cash commitments at the closing of each drilling partnership.

In 1984, the Company began sponsoring drilling partnerships. The Company-sponsored partnerships had $90 million in subscriptions in 2006, $116 million in subscriptions in 2005, and $100 million in subscriptions in 2004. During 2006, the Company sponsored one drilling partnership to which it contributed $38.9 million and received a 37% working interest in the partnership. While funds were received by the Company pursuant to drilling contracts in the years indicated, the Company recognizes revenues from drilling operations on the percentage of completion method as the wells are drilled, rather than when funds are received. Substantially all of the Company's drilling and development funds are now received from partnerships in which the Company serves as managing general partner. However, because wells produce for a number of years, the Company continues to serve as operator for a number of unaffiliated parties. The Company plans to offer $110 million in subscriptions through a private placement in 2007.

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

The Company's drilling contracts with its investor partners have historically taken many different forms. Beginning with the last Company-sponsored partnership of 2005 (for which revenue generating activities did not commence until early 2006), partnership wells are drilled on a "cost-plus" basis, whereby the Company bills investors for the actual cost of the wells plus an agreed upon mark-up above the costs. In the past the drilling contracts could be classified as on a footage-based rate, whereby the Company received drilling and completion payments based on the depth of the well. The Company may also purchase an additional working interest in the partnership properties. In its financial reporting, the Company reports only its proportionate share of oil and gas reserves, production, oil and gas sales and costs associated with wells in which other investors participate. The level of the Company's drilling and development activity is dependent upon the amount of subscriptions in its public drilling partnerships and investments from other partnerships or other joint venture partners. Accepting investments from third party investors and Company sponsored partnerships enables the Company to diversify its holdings, thereby reducing the risk of the Company's investments. The Company's management believes that investments in drilling activities, whether through Company-sponsored partnerships or other sources, are influenced in part by the favorable treatment that such limited partner investments receive under the federal income tax laws. No assurance can be given that the Company will continue to have access to funds generated through these financing vehicles or that the favorable tax treatment will continue.

Purchases of Producing Properties

In addition to drilling new wells, the Company continues to pursue opportunities to purchase existing wells from other owners, as well as greater ownership interests in the wells it operates. Generally, outside interests purchased include a majority interest in the wells and the right to operate the wells. During 2006, the Company successfully acquired the stock of Unioil, Inc., a small independent producer with properties primarily in the Wattenberg Field in Colorado, for a total of $18.6 million. In addition, in January 2007, the Company completed the purchase of approximately 144 oil and gas wells and 8,160 acres of leaseholds in the Wattenberg Field from EXCO Resources. Also in January 2007, the Company purchased the outside partnership interests in 44 partnerships which had been formed primarily in the late 1980s and 1990s. These interests constituted the majority of the interests in 718 wells, primarily in the Appalachian and Michigan Basins. In February 2007, the Company acquired 28 producing wells and associated undeveloped acreage in Colorado for $11.8 million.

Production

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

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Production (1):					
Oil (MBbl)	**631**	439	381	289	227
Natural Gas (MMcf)	**13,161**	11,031	10,372	8,712	6,462
Equivalent (MMcfe) (2)	**16,949**	13,665	12,659	10,449	7,824
Average sales price:					
Oil (per Bbl) (3)	**$59.33**	$50.56	$38.00	$29.43	$24.41
Natural gas (per Mcf) (3)	**$5.91**	$7.29	$5.30	$4.58	$2.65
Equivalent average sales price (per Mcfe)	**$6.80**	$7.51	$5.49	$4.63	$2.90
Average production cost (lifting cost)					
Per equivalent (Mcfe) (4)	**$1.23**	$1.19	$1.12	$0.93	$0.76

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

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

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

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

Natural Gas Sales

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

The Company sells its natural gas to industrial end-users, utilities, other gas marketers, and other wholesale gas purchasers. During 2006, natural gas produced by the Company was sold at prices ranging from $2.26 to $15.70 per Mcf, depending upon well location, the date of the sales contract and other factors. The weighted net average price of natural gas sold by the Company during 2006 was $5.91 per Mcf.

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

Oil Sales

The majority of the Company's wells in the Wattenberg Field in Colorado and the Company's North Dakota wells produce oil in addition to natural gas. As of December 31, 2006, oil represented about 13% of the Company's total equivalent reserves and accounted for approximately 33% of the Company's oil and gas sales for the year ended December 31, 2006.

The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company's crude oil production is sold to purchasers at or near the Company's wells under short-term purchase contracts. During 2006, oil produced by the Company sold at prices ranging from $53.75 to $71.77 per barrel, depending upon the location and quality of oil. In 2006, the weighted net average price per barrel of oil sold by the Company was $59.33.

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

Natural Gas Marketing

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

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

Commodity Risk Management Activities

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

RNG has extensive experience with the use of cash-settled derivatives to reduce the risk and impact of natural gas price changes. These financial derivatives are used by RNG to coordinate fixed purchases and sales, and by the Company to establish "floors" and "ceilings" or "collars" on the possible range of the prices realized for the sale of natural gas and oil. RNG also enters into back-to-back fixed-price purchases and sales contracts with counterparties. These fixed physical contracts meet the FAS 133 definition of a derivative. Both types of derivatives (i.e., the physical deals and the cash settled contracts) are carried on the balance sheet at fair value with changes in fair values recognized currently in the income statement.

The Company is subject to price fluctuations for natural gas sold in the spot market and under market index contracts. The Company continues to evaluate the potential for reducing these risks by entering into derivative transactions. In addition, the Company may close out any portion of derivatives that may exist from time to time which may result in a realized gain or loss on that derivative transaction. The Company economically manages the price risk on only a portion of its anticipated production, so some of the production is subject to the full fluctuation of market pricing.

Well Operations

At December 31, 2006, the Company had an interest in approximately 1,365 wells in the Appalachian Basin, 206 wells in the Michigan Basin and 1,530 wells in the Rocky Mountain Region. The Company's ownership interest in these wells ranges from greater than 0% to 100% and, on average, the Company has an approximate 51.4% ownership interest in the wells it operates.

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

Transportation

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

Governmental Regulation

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

Regulation of Oil and Natural Gas Exploration and Production

The Company's exploration and production business is subject to various federal, state and local laws and regulations on taxation, the development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, the Company must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. The permits and approvals include those for the drilling of wells, and the regulation includes maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. The Company's operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore, more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. Where wells are to be drilled on state or federal leases, additional regulations and conditions may apply. The effect of these regulations may limit the amount of oil and natural gas the Company can produce from its wells and may limit the number of wells or the locations at which the Company can drill. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning the Company's oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where the Company has production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit its reserves. Inasmuch as such laws and regulations are frequently expanded, amended and reinterpreted, the Company is unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Historically, the price of natural gas was subject to limitation by federal legislation. The Natural Gas Wellhead Decontrol Act (the "Decontrol Act") removed, as of January 1, 1993, all remaining federal price controls from natural gas sold in "first sales" on or after that date. The Federal Energy Regulatory Commission ("FERC")'s jurisdiction over natural gas transportation was unaffected by the Decontrol Act. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at market prices, there are a number of proposed bills in the United States Congress to reenact price controls or impose "windfall profits" or similar taxes in the future on oil and gas prices. The passage of one of those bills or similar legislation could have the impact of reducing the price received by the Company for its production, or substantially increasing the tax burden associated with its production operations.

The Company moves gas through pipelines owned by other companies, and sells gas to other companies that also utilize common carrier pipeline facilities. Gas pipeline interstate transmission and storage activities are subject to regulation by the FERC under the Natural Gas Act of 1938 ("NGA") and under the Natural Gas Policy Act of 1978, and, as such, rates and charges for the transportation of natural gas in interstate commerce, accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC Order 2004 "Standards of Conduct for Transmission Providers" governs how interstate pipelines communicate and do business with their energy affiliates. One of the cornerstones of Order 2004 is that interstate pipelines will not operate their pipeline systems to preferentially benefit their energy affiliates.

Each interstate natural gas pipeline company establishes its rates primarily through the FERC's ratemaking process. Key determinants in the ratemaking process are:

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- volume throughput assumptions.

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

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

Environmental Regulations

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

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

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

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

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

The Company's expenses relating to preserving the environment during 2006 were not significant in relation to operating costs and the Company expects no material change in 2007. Environmental regulations have had no materially adverse effect on the Company's operations to date, but no assurance can be given that environmental regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on the Company's business, financial condition or results of operations.

Operating Hazards and Insurance

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

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

Competition

The Company's management believes that its exploration, drilling and production capabilities and the experience of its management and professional staff generally enable it to compete effectively. The Company encounters competition from numerous other oil and natural gas companies, drilling and income programs and partnerships in all areas of its operations, including drilling and marketing oil and natural gas and obtaining desirable oil and natural gas leases and producing properties. Many of these competitors possess larger staffs and greater financial resources than the Company, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. The Company's ability to explore for oil and natural gas prospects and to acquire additional properties in the future depends upon its ability to conduct its operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. The Company competes with a number of other companies that offer interests in drilling partnerships with a wide range of investment objectives and program structures. Competition for investment capital for both public and private drilling programs is intense. The Company also faces intense competition in the marketing of natural gas from competitors including other producers as well as marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic oil and natural gas exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future. During 2006, the industry experienced continued strong demand for drilling services and supplies. This is resulting in increasing costs, and in some cases the demand for supplies and services exceeds the available supplies. This can result in higher well costs and delays in the execution of planned drilling operations. Factors affecting competition in the oil and natural gas industry include price, location of drilling, availability of drilling prospects and drilling rigs, pipeline capacity, quality of production and volumes produced. The Company's management believes that it can compete effectively in the oil and natural gas industry on each of the foregoing factors. Nevertheless, the Company's business, financial condition or results of operations could be materially adversely affected by competition.

Employees

As of December 31, 2006, the Company had 189 employees, including 104 in production and seven in natural gas marketing, 32 in exploration and development, 31 in finance, accounting and data processing, and 15 in administration. The Company's engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and pipeline systems. In addition, the Company retains subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites, with the Company's employees supervising the activities of the subcontractors. In 2006, the total number of Company employees increased by 39.

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

ITEM 1A. RISK FACTORS

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

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

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

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

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

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs over the economic life of the properties. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate. The Company's estimates of oil and gas reserves are prepared by independent petroleum engineers, using pricing, production, cost, tax and other information provided by the Company. The reserve estimates are based on certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect the estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, future depreciation, depletion and amortization rates and amounts, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Some of the Company's reserve estimates must be made with limited production history, which renders these reserve estimates less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which the reserve estimates are based, as described above, often result in the actual quantities of oil and gas recovered being different from earlier reserve estimates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The Company's drilling margins associated with its limited partnership programs are dependent upon the capital raised by the Company as a sponsor of limited partnerships. The Company sells oil and natural gas partnerships through a network of non-affiliated NASD broker dealers. The largest of those broker dealers sold about 11% of the partnership units in 2006. Investors in the partnerships benefit from the tax deductions generated by the intangible drilling costs and the cash flow generated by the partnerships. If the tax laws were changed to reduce or eliminate the tax advantages, if the cash flow from the partnerships were to decline due to poor performing wells or lower energy prices, or if the brokers decide to stop offering the Company's partnerships for some reason, the sales of the partnership units would decline, reducing or eliminating the revenue and profits associated with the drilling and development business segment. As a result, the Company's operations and profitability would be adversely affected.

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

The Company conducted exploratory drilling in 2006 and plans to continue exploratory drilling in 2007 in order to identify additional opportunities for future development. Under the "successful efforts" method of accounting used by the Company, the cost of unsuccessful exploratory wells must be charged to expense in the period when they are determined to be unsuccessful. In addition lease costs for acreage condemned by the unsuccessful well must also be expensed. In contrast, unsuccessful development wells are capitalized as a part of the investment in the field where they are located. Because exploratory wells generally are more likely to be unsuccessful than development wells, the Company anticipates that some or all of its exploratory wells may not be productive. The costs of such unsuccessful exploratory wells could result in a significant reduction in the Company's profitability in periods when the costs are required to be expensed.

The Company may incur substantial impairment write-down, if the price of oil and natural gas declines or due to revisions in its estimates of its reserves.

If oil and natural gas prices decline, if development costs exceed previous estimates, or if management's estimate of the recoverable reserves on a property is revised downward, the Company may be required to record additional non-cash impairment write-downs in the future, which would result in a negative impact to its financial position. The Company reviews its proved oil and gas properties for impairment on a quarterly basis. To determine if a depletable unit is impaired, the Company compares the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon the Company's independent reserve engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, the Company recognizes an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis. Fair value is estimated to be the present value of the aforementioned expected future net cash flows. Any impairment charge incurred is recorded as a reduction to the asset value. This calculation is subject to a large degree of judgment, including the determination of the future depletable units, future cash flows and fair value. In 2006, the Company recorded an impairment charge of $1.5 million related to its Nesson Field in North Dakota. There were no impairments during 2005 or 2004.

Rising finding and development costs may impair the Company's profitability.

In order to continue to grow and maintain its profitability, the Company must annually add new reserves exceeding its yearly production at a finding and development cost that yields an acceptable operating margin and depreciation, depletion and amortization rate. Without cost effective exploration, development or acquisition activities, production, reserves and profitability will decline over time. Given the relative maturity of most gas basins in North America and the high level of activity in the industry, the cost of finding new reserves through exploration and development operations has been increasing. The acquisition market for natural gas properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America.

Acquisition values climbed toward historic highs during 2006 on a per unit basis, particularly in the Rocky Mountain Region, and the Company believes these values may continue to increase in 2007. This increase in finding and development costs is resulting in higher depreciation, depletion and amortization rates. If the upward trend in finding and development costs continues, the Company will be exposed to an increased likelihood of a write-down in carrying value of its natural gas and oil properties in response to falling prices and reduced profitability of operations.

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

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

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

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

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

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

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

A substantial part of the Company's oil and gas production is located in the Rocky Mountains, making it vulnerable to risks associated with operating in one major geographic area.

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

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

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

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

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

The Company has limited control over activities on properties it does not operate, which could reduce its production and revenues.

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

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

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

The Company's derivative activities could result in financial losses or could reduce its income.

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

The inability of one or more of the Company's customers to meet their obligations may adversely affect the Company's financial results.

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

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

The Company depends on the performance of its executive officers and other key employees. The loss of any member of senior management or other key employees could negatively impact the Company's ability to execute its strategy.

Terrorist attacks or similar hostilities may adversely impact the Company's results of operations.

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

The Company's insurance coverage may not be sufficient to cover some liabilities or losses that the Company may incur.

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

The Company may not be able to keep pace with technological developments in its industry.

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

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

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

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

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

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

If litigation were commenced against the Company for alleged royalty practices and payments, the cost of our defending the lawsuit could be significant and any resulting judgments against the Company could have a material adverse impact upon our financial condition.

Recent litigation has commenced against several companies in the Company's industry regarding royalty practices and payments in jurisdictions where the Company conducts business. While the Company's business model differs from those of the litigants in those cases, and the Company has not been named in any litigation, has not had similar litigation commenced, and has not been threatened with such litigation, there can be no assurance that the Company will not become a party to such litigation or to similar litigation in the future. If litigation of this nature were commenced against us, even if the ultimate outcome of the litigation resulted in a judgment for the Company, the cost of defending the Company could be significant. These costs would be reflected in terms of dollar outlay as well as the amount of time, attention and other resources that the Company's management would have to appropriate to the defense. Although the Company cannot predict an eventual outcome were litigation to be commenced against us, a judgment in favor of the plaintiffs could have a material adverse impact upon the Company's financial condition.

Material weaknesses in the Company's internal control over financial reporting and disclosure controls and procedures could adversely impact the reliability of its internal control over financial reporting, its ability to timely file certain reports with the SEC, the liquidity of the market for its common stock and its ability to raise investment capital to support its drilling operations in the future.

Management has assessed the effectiveness of internal control over financial reporting as of December 31, 2006, and this assessment identified material weaknesses in internal control over financial reporting and disclosure controls and procedures. For discussion of these material weaknesses and the Company's remediation plans, please see Part II, Item 9A, "Controls and Procedures" of this report. As a result of these material weaknesses, management concluded that the Company's internal control over financial reporting and disclosure controls and procedures were not effective as of December 31, 2006.

Material weaknesses were also identified during management's assessment of the internal control environment as of December 31, 2005. A description of these material weaknesses can be found in Part II, Item 9A, "Controls and Procedures" of the Annual Report for fiscal year 2005. As a result of these material weaknesses, management concluded that the Company's internal control over financial reporting was not effective as of December 31, 2005.

The Company's material weaknesses have led to restatements of its consolidated financial statements in connection with the filing of its annual report on Form 10-K for the year ended December 31, 2005. These material weaknesses have also contributed to the delays the Company has experienced in filing its annual reports on Form 10-K for the years ended December 31, 2006 and 2005. In addition, the Company did not timely file with the SEC its Form 10-Q for the quarters ended March 31, 2007 and 2006. A continued inability to timely file its periodic reports with the SEC could involve a number of significant risks, which could have an adverse impact on the Company's operations, on the market for its stock and investors generally, including:

- The potential delisting of the Company's common stock. The Company's failure to file its periodic reports timely constitutes a violation of the listing standards of the NASDAQ Stock Market. If the NASDAQ Stock Market ceases to grant the Company extensions of time in which to file its reports, NASDAQ has the right to begin proceedings to delist the Company's common stock. The Company had a hearing before the NASDAQ Listing Qualifications Panel ("Panel") on May 10, 2007, regarding the Company's failure to file timely its Form 10-K for the year ended December 31, 2006. The Panel also considered the Company's failure to file timely its Form 10-Q for the period ended March 31, 2007. It is possible that the Panel might order the delisting of the Company's stock from NASDAQ. The delisting of the Company's common stock could have a material adverse effect on the Company by:

- reducing the liquidity and market price for its common stock;
- reducing the number of investors willing to hold or acquire its common stock, which in turn could further reduce its stock's liquidity; and
- limiting the ability of investors to sell the Company's common stock.

If the Company is unable to prepare and file its annual report on Form 10-K in a timely manner, and to a lesser degree, if the Company is unable to prepare and file one or more of its quarterly reports on Form 10-Q in a timely manner, the Company might be unable to raise capital for Company operations, either by its selling of its securities or through a borrowing facility. In this regard, under those circumstances the Company could be faced with any of the following risks:

- If the Company were unable to file its financial statements because it is unable to file its annual report on Form 10-K and/or its quarterly financial reports on Form 10-Q, the Company would not be able to raise capital from the public markets through the sale of its stock or debt securities through an SEC-registered public offering. Likewise, the Company's inability to file its required periodic reports with the SEC in a timely fashion may hinder its ability to raise capital through the private placement of its securities.

- A major component of the Company's business plan is to raise drilling capital through its public and private sales of partnership interests. If the Company is unable to file its annual reports and/or quarterly reports in a timely fashion, it will not be able to access the public markets through an SEC-registered securities offering; and it may have difficulty in accessing the private placement market for capital through an SEC-exempt securities offering.

- The Company's credit facility with JPMorgan Chase and BNP Paribas ("Lenders") requires the Company to be current in its filing of its required periodic reports with the SEC. If the Company is unable to file its annual reports and/or quarterly reports with the SEC when due, the Lenders might declare the credit facility to be in default and any loans then outstanding under the credit facility would be immediately due and payable. Additionally, even if the Lenders did not declare a default and accelerate repayment of outstanding amounts, the Company might not be able to borrow further amounts under the facility. Moreover, the Company under those circumstances might not be able to negotiate and arrange alternative financing to support its drilling operations. See Note 5 to consolidated financial statements for discussion related to the current waiver the Company has received under the credit facility.

If the Company is unable to raise drilling capital and funding for its operations as cited in the three preceding paragraphs, then it would be likely that its drilling operations would be materially adversely affected; and that its ability to grow the Company in the historical manner would be severely hampered. Moreover, it is likely that the Company's business operations could be materially adversely damaged.

- Currently, the Company has several employee and director stock benefit plans in which its common stock available under the plans has been registered by SEC Form S-8 under the Securities Act of 1933. Under SEC regulations, the Company's failure to file with the SEC required annual reports on Form 10-K will cause its Form S-8 registration statement to be stale – that is, not current as to information about the Company. The result is that the Form S-8 would no longer be in compliance with the requirements of the Securities Act, compliance with which allowed the Company to offer these stock benefits to Company employees for their investment. Consequently, if the Company does not file its annual reports with the SEC in a timely fashion, the Company will have to suspend the availability of these plans, including the Company's 401(k) and Profit Sharing Plan, to allow Company employees to exercise any Company stock options that they hold or to choose to invest in Company common stock under the 401(k) and Profit Sharing Plan. Additionally, those Company employees who own shares of the Company's common stock might find it more difficult to sell their shares in the market if the Company's common stock is delisted from the NASDAQ Stock Market.

Furthermore, the number of subsequent failures to timely file any future periodic reports with the SEC could increase the likelihood, frequency of occurrence, and severity of the impact of any of the risks described above.

Since the identification of these material weaknesses, the Company has implemented and is continuing to implement various procedures intended to improve its internal control over financial reporting and disclosure controls and procedures. No assurance can be given that the Company will be effective in remedying all identified deficiencies in its internal control over financial reporting and disclosure controls and procedures. The Company has implemented procedures to remediate the material weaknesses identified during fiscal year 2005, and while management believes that the reconciliation, capitalization assessment, valuation, completeness determination and monitoring procedures and controls implemented since December 31, 2006, will, when demonstrated to be operating effectively, allow management to conclude that the material weaknesses identified in 2006 have been remediated, there can also be no assurance that the material weaknesses will be rectified in a timely fashion or that additional material weaknesses will not arise and be identified.

ITEM 1B. UNRESOLVED STAFF COMMENTS

In September 2006, the Company received written comments from the staff of the SEC regarding its Annual Report on Form 10-K for the year ended December 31, 2005 ("2005 Form 10-K"), to which the Company has subsequently provided responses. The staff have since indicated to the Company that they have no further outstanding comments related to the Company's 2005 Form 10-K. As a result, the Company does not believe it has any currently outstanding comments with the staff with regard to its own filings.

However, the Company, as managing general partner, has not yet filed all Company-sponsored partnerships' 2005 Forms 10-K, related to which the Company has previously issued filings on Forms 8-K (dated August 25, 2005, and November 15, 2005) advising that, due to errors in its accounting policies and practices, no reliance should be placed on the related financial information, nor on the auditors' opinion related thereto. As of the date of this filing, the Company has not completed the corrections of these errors and is delinquent in its filing requirements for 24 such Company-sponsored partnerships with regard to the year ended December 31, 2005. Additionally, for each of the same Company-sponsored partnerships, the Company has not filed related Forms 10-Q for the quarterly periods ended March 31, 2006, June 30, 2006, September 30, 2006, and March 31, 2007, or Forms 10-K for the year ended December 31, 2006.

ITEM 2. PROPERTIES

Summary of Productive Wells

The table below shows the number of the Company's productive gross and net wells at December 31, 2006.

	Productive Wells			
	Gas		Oil	
Location	Gross	Net	Gross	Net
Colorado	1,445	794.0	25	19.3
Kansas	40	39.0	-	-
Michigan	199	106.0	7	2.7
North Dakota	5	1.1	12	6.2
Pennsylvania	420	93.1	-	-
Tennessee	1	0.7	35	13.7
West Virginia	905	515.9	4	1.7
Wyoming	-	-	3	0.7
Total	3,015	1,549.8	86	44.3

Oil and Gas Reserves

All of the Company's natural gas and oil reserves are located in the United States. The Company's approximate net proved reserves were estimated by independent petroleum engineers, to be 279,078 MMcf of natural gas and 7,272 MBbls of oil at December 31, 2006, 247,288 MMcf of natural gas and 4,538 MBbls of oil at December 31, 2005, and 197,549 MMcf of natural gas and 3,316 MBbls of oil at December 31, 2004.

The Company's approximate net proved developed reserves were estimated, by independent petroleum engineers, to be 158,978 MMcf of natural gas and 4,629 MBbls of oil at December 31, 2006, 155,354 MMcf of natural gas and 3,860 MBbls of oil at December 31, 2005, and 146,152 MMcf of natural gas and 3,190 MBbls of oil at December 31, 2004.

The Company utilized the services of two independent petroleum engineers for its 2006 independent reserve report. Wright & Company prepared the reserve report for the Appalachian and Michigan Basin and Northeast Colorado ("NECO") properties. Ryder Scott Company, LLP prepared the reserve report for the Rocky Mountain Region, with the exception of the NECO properties. Wright & Company prepared all of the reserve reports for the Company for 2005 and 2004 with the exception of 2005 North Dakota wells which were prepared by Ryder Scott Company.

The Company's oil and natural gas reserves by region are as follows as of December 31, 2006:

	Oil (MBbl)	Gas (MMcf)	Natural Gas Equivalent (MMcfe)	%
Proved Developed Reserves				
Appalachian Basin	29	35,840	36,014	19.3%
Michigan Basin	36	20,331	20,547	11.0%
Rocky Mountain Region	4,564	102,807	130,191	69.7%
Total Proved Developed Reserves	4,629	158,978	186,752	100.0%
Proved Undeveloped Reserves				
Appalachian Basin	-	-	-	0.0%
Michigan Basin	-	685	685	0.5%
Rocky Mountain Region	2,643	119,415	135,273	99.5%
Total Proved Undeveloped	2,643	120,100	135,958	100.0%
Total Proved Reserves				
Appalachian Basin	29	35,840	36,014	11.2%
Michigan Basin	36	21,016	21,232	6.6%
Rocky Mountain Region	7,207	222,222	265,464	82.2%
Total Proved Reserves	7,272	279,078	322,710	100.0%

No major discovery or other favorable or adverse event that would cause a significant change in estimated reserves on the properties owned by the Company as of December 31, 2006, is believed by the Company to have occurred since December 31, 2006, with the exception of the following acquisitions:

- In January 2007, the Company acquired 144 oil and gas wells and 8,160 acres of leasehold in the Wattenberg Field area of the DJ Basin, Colorado and an increased net interest in 718 wells currently operated by the Company.
- In February 2007, the Company acquired 28 producing wells and associated undeveloped acreage in the Wattenberg Field.

Reserves cannot be measured exactly, because reserve estimates involve subjective judgment. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes.

The standardized measure of discounted future estimated net cash flows attributable to the Company's proved oil and gas reserves, giving effect to future estimated income tax expenses, was estimated by the Company's independent petroleum engineers to be $215.7 million as of December 31, 2006, $405.4 million as of December 31, 2005, and $229.4 million as of December 31, 2004. These amounts are based on December 31 commodity prices in the respective years. The values expressed are estimates only, and may not reflect realizable values or fair market values of the natural gas and oil ultimately extracted and recovered. The standardized measure of discounted future net cash flows may not accurately reflect proceeds of production to be received in the future from the sale of natural gas and oil currently owned and does not necessarily reflect the actual costs that would be incurred to acquire equivalent natural gas and oil reserves.

Net Proved Natural Gas and Oil Reserves

The proved reserves of natural gas and oil of the Company as estimated by the Company's independent petroleum engineers at December 31, 2006, are set forth below. These reserves have been prepared in compliance with the rules of the SEC based on December 31, 2006, prices. These reserve estimates were not filed with another Federal authority or agency since the Company filed its Form 10-K with the SEC on May 31, 2006, for the year ended December 31, 2005. An analysis of the change in estimated quantities of natural gas and oil reserves from January 1, 2006 to December 31, 2006, all of which are located within the United States, is shown below:

	Natural Gas (MMcf)	Oil (MBbl)
Proved developed and undeveloped reserves:		
Beginning of year	247,288	4,538
Revisions of previous estimates	(28,067)	35
Beginning of year as revised	219,221	4,573
New discoveries and extensions		
Rocky Mountain region	70,499	3,148
Dispositions to partnerships	(1,215)	(92)
Acquisitions		
Michigan basin	35	-
Rocky Mountain region	3,477	274
Appalachian basin	222	-
Production	(13,161)	(631)
End of year	279,078	7,272
Proved developed reserves:		
Beginning of year	155,354	3,860
End of year	158,978	4,629

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

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves at December 31, 2006. Future cash inflows are computed by applying year-end prices of natural gas and oil relating to the Company's proved reserves to year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs, assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at December 31, 2006, to the future pretax net cash flows, less the tax basis of the properties, and gives effect to permanent differences, tax credits and allowances related to the properties. (in thousands)

Future estimated cash flows	$ 1,804,796
Future estimated production costs	(571,346)
Future estimated development costs	(373,460)
Future estimated income tax expense	(334,536)
Future net cash flows	525,454
10% annual discount for estimated timing of cash flows	(309,792)
Standardized measure of discounted future estimated net cash flows	$ 215,662

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows from January 1, 2006, through December 31, 2006: (in thousands)

Sales of oil and gas production net of production costs	$ (94,337)
Net changes in prices and production costs	(299,721)
Extensions, discoveries, and improved recovery, less related costs	46,109
Sales of reserves	(3,356)
Purchase of reserves	11,003
Development costs incurred during the period	20,051
Revisions of previous quantity estimates	(23,146)
Changes in estimated income taxes	120,818
Accretion of discount	62,838
Timing and other	(30,027)
Total	$ (189,768)

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

Substantially all of the Company's natural gas and oil reserves have been mortgaged or pledged as security for the Company's credit agreement. See Note 5 to the notes to the Company's financial statements.

Oil and Natural Gas Leases

The following table sets forth the by state leased acres available to the Company for development of oil and natural gas as of December 31, 2006.

Colorado	42,900
Kansas	23,000
Michigan	200
New York	12,800
North Dakota	89,600
Wyoming	32,000
Total	200,500

Title to Properties

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

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

Facilities

The Company completed the construction of its new corporate headquarters in Bridgeport, West Virginia, which was occupied in December 2006. The Company intends to begin construction of a second office building adjacent to its new corporate headquarters in 2007. The Company's prior Bridgeport offices, consisting of two buildings, will be placed on the market and available for sale sometime in 2007. The Company has an operating lease for its Denver Office in Denver, Colorado.

The Company owns a field operating facility in each of Harrison and Gilmer Counties, West Virginia, Alpena County, Michigan and Weld County, Colorado. The Company has operating leases for two field offices in Colorado and one in Pennsylvania.

ITEM 3. LEGAL PROCEEDINGS

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

Recent litigation has commenced against several companies in our industry regarding royalty practices and payments in jurisdictions where the Company conducts business. While the Company's business model differs from those of the litigants in those cases, and the Company has not been named in any litigation, has not had similar litigation commenced, nor has such litigation been threatened, there can be no assurance that the Company will not be a party to any litigation or to similar litigation in the future.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

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

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDERS MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

The authorized capital stock of the Company consists of 50,000,000 shares of common stock, par value $0.01 per share. There were 14,887,530 shares of common stock issued and outstanding as of April 30, 2007. The common stock of the Company is traded on the NASDAQ Global Select Market under the ticker symbol PETD.

The following table sets forth the range of high and low sales prices for the Company's common stock as reported on the NASDAQ Global Select Market for the periods indicated below.

	High	Low
2006		
First Quarter	$46.06	$32.46
Second Quarter	45.07	32.89
Third Quarter	44.54	33.32
Fourth Quarter	46.61	36.96
2005		
First Quarter	44.19	35.72
Second Quarter	37.28	22.65
Third Quarter	40.00	32.54
Fourth Quarter	39.55	30.53

As of April 30, 2007, there were approximately 908 record holders of the Company's common stock.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 - 20, 2006	334,242	$40.93	334,242	1,477,109
Total	334,242	$40.93	334,242	1,477,109

In January 2006, the Company announced that its Board of Directors had authorized the Company to purchase up to 10% (1,627,500 shares) of its outstanding common stock during 2006. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that management deemed appropriate. On October 20, 2006, the Company completed its January 2006 share purchase program. Total shares purchased in 2006 pursuant to the program were 1,627,500 common shares at a cost of $66.3 million ($40.75 average price paid per share), including 100,000 shares from an executive officer of the Company at a cost of $4.1 million ($40.66 price paid per share). All shares purchased in accordance with the program were subsequently retired.

On October 16, 2006, the Board of Directors of the Company approved a second 2006 share purchase program authorizing the Company to purchase up to 10% of the Company's then outstanding common stock (1,477,109 shares) through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time.

ITEM 6. SELECTED FINANCIAL DATA (in thousands, except per share data)

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Revenues:					
Oil and gas well drilling operations	**$ 17,917**	$ 99,963	$ 94,076	$ 57,510	$ 45,842
Gas sales from marketing activities	**131,325**	121,104	94,627	73,132	43,537
Oil and gas sales	**115,189**	102,559	69,492	48,394	22,688
Well operations and pipeline income	**10,704**	8,760	7,677	6,907	5,771
Oil and gas price risk management gains (losses), net	**9,147**	(9,368)	(3,085)	(812)	(370)
Other income	**2,221**	2,180	1,696	3,338	2,549
Total revenues	**286,503**	325,198	264,483	188,469	120,017
Costs and expenses:					
Cost of oil and gas well drilling operations	**12,617**	88,185	77,696	46,946	37,859
Cost of gas marketing activities	**130,150**	119,644	92,881	72,361	43,168
Oil and gas production and well operations costs	**29,021**	20,400	17,713	13,630	8,672
Exploration cost	**8,131**	11,115	-	-	-
General and administrative expense	**19,047**	6,960	4,506	4,975	4,392
Depreciation, depletion and amortization	**33,735**	21,116	18,156	15,313	12,602
Total costs and expenses	**232,701**	267,420	210,952	153,225	106,693
Gain on sale of leaseholds	**328,000**	7,669	-	-	-
Income from operations	**381,802**	65,447	53,531	35,244	13,324
Interest income	**8,050**	898	185	190	248
Interest expense	**(2,443)**	(217)	(238)	(816)	(1,505)
Income before income taxes and cumulative effect of change in accounting principle	**387,409**	66,128	53,478	34,618	12,067
Income taxes	**149,637**	24,676	20,250	11,934	3,186
Income before cumulative effect of change in accounting principle	**237,772**	41,452	33,228	22,684	8,881
Cumulative effect of change in accounting principle (net of taxes of $1,392)	**-**	-	-	(2,271)	-
Net income	**$ 237,772**	$ 41,452	$ 33,228	$ 20,413	$ 8,881
Basic earnings per common share	**$ 15.18**	$ 2.53	$ 2.05	$ 1.30	$ 0.56
Diluted earnings per share	**$ 15.11**	$ 2.52	$ 2.00	$ 1.25	$ 0.55

	December 31,				
	2006	2005	2004	2003	2002
Total Assets	**$ 884,287**	**$ 444,361**	$ 329,453	$ 294,004	$ 198,838
Working Capital (Deficit)	**$ 29,180**	**$ (16,763)**	$ 231	$ 7,287	$ 2,645
Long-Term Debt	**$ 117,000**	**$ 24,000**	$ 21,000	$ 53,000	$ 25,000
Stockholders' Equity	**$ 360,144**	**$ 188,265**	$ 154,021	$ 112,559	$ 92,887

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

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

Results of Operations

Management Overview

The Company recorded strong revenues and cash flows for 2006. Although average commodity prices declined during 2006 compared to 2005, a record 24% production increase more than compensated for the price decline, as oil and gas sales increased $12.6 million over 2005. The recent trend in declining profit margins on the Company's oil and gas well drilling operations segment reversed during the latter part of the year, as the Company switched from footage-based drilling contracts, which lead to the declining margins, to cost-plus contracts where the Company does not bear the risk of cost changes on the wells it drills for the partnerships. However, this change in type of contract, which allowed the Company to recognize a contracted rate of profit from oil and gas well drilling operations, resulted in an equal $74.6 million decline in revenue and related costs. See "Drilling Operations" below for further discussion.

The principal business event of the year was the sale of undeveloped property in the Grand Valley Field in the third quarter for a gain of $328 million, with approximately $26 million in additional gains on the transaction deferred to future periods, to be recognized if wells are drilled on certain properties. The proceeds of the sale, the qualification of the sale for like-kind exchange tax status and the property purchased during 2006 and 2007 have substantially strengthened the Company's financial position and positioned it for continuing growth in the coming periods.

Year Ended December 31, 2006, Compared to December 31, 2005

Revenues

Total revenues for the year ended December 31, 2006, were $286.5 million compared to $325.2 million for the year ended December 31, 2005, a decrease of approximately $38.7 million, or 11.9%. The decrease was primarily attributable to a decrease in drilling revenues of $82.1 million partially offset by the increased oil and gas sales from both gas marketing activities and the Company's share of production for a total of $22.9 million and the swing from a $9.4 million loss in oil and gas price risk management for the year ended December 31, 2005, to a gain of $9.1 million for the year ended December 31, 2006. See "Drilling Operations" below for an explanation of the impact the new cost-plus drilling arrangements and related accounting had on drilling revenues for the year 2006.

Costs and Expenses

Total costs and expenses for the year ended December 31, 2006, were $232.7 million compared to $267.4 million for the year ended December 31, 2005, a decrease of approximately $34.7 million, or 13%. The decrease was primarily attributable to decreases in the cost of oil and gas well drilling operations of $75.6 million and exploration cost of $3 million offset in part by increases in the cost of gas marketing activities of $10.5 million, oil and gas production and well operations costs of $8.6 million, general and administrative expenses of $12.1 million and depreciation, depletion and amortization of $12.6 million. See "Drilling Operations" below for an explanation of the impact of the new cost plus drilling arrangements and related accounting had on drilling expenses for the year 2006.

Drilling Operations

During the first quarter of 2006, the Company began operating and recognizing revenues for its cost-plus service arrangements with new partnerships, in addition to its footage-based drilling arrangements on earlier partnerships. The cost-plus drilling arrangements became effective with the private program partnership funded by the Company in December 2005 and continued in the 2006 partnership funded on September 1, 2006. Drilling revenues for the year ended December 31, 2006, were $17.9 million, net of $74.6 million of costs related to drilling arrangements accounted for on the cost-plus basis, compared to $100 million for the year ended December 31, 2005, a decrease of $82.1 million. The decrease was primarily due to the change in the Company's drilling contracts, which resulted in net revenue recognition related to the new contracts.

The costs of oil and gas well drilling operations for the year ended December 31, 2006, was $12.6 million compared to $88.2 million for the year ended December 31, 2005, a decrease of $75.6 million. The decrease in costs is primarily attributable to the Company's revenue reporting for its new cost-plus drilling arrangements, which reduced drilling costs by $74.6 million for the year as discussed above.

The new cost-plus drilling arrangement eliminates the Company's risk of loss from the contract drilling services it provides the partnerships. The Company's drilling revenues and corresponding costs are presented net as a one-lined income statement item representing only the gross profit portion of the drilling arrangement. The new cost-plus contract impacted the current year period by reducing drilling revenues and drilling costs by $74.6 million as outlined in the table below (in millions):

	Year ended December 31,			
	2006			2005
	Drilling Service Revenue/Cost	Direct Reimbursed Cost	Revenue/Cost including reimburse-ment from Partnerships	Drilling Service Revenue/Cost
Oil and gas well drilling operations	$ 17.9	$ 74.6	$ 92.5	$ 100.0
Total revenues	$ 286.5	$ 74.6	$ 361.1	$ 325.2
Cost of oil and gas well drilling operations	$ 12.6	$ 74.6	$ 87.2	$ 88.2
Total costs and expenses	$ 232.7	$ 74.6	$ 307.3	$ 267.4

Although the Company changed to cost-plus drilling arrangements with its two recent partnerships, prior footage-based contracts continue to be in effect, and realized a loss of $2.1 million during 2006. This loss contributed to the decrease in the drilling and development segment gross margin from $11.8 million for the year ended December 31, 2005, to $5.3 million for the year ended December 31, 2006. This loss was due to some drilling and completion difficulties incurred and significantly increasing well drilling and completion costs, particularly the costs of fracturing and rising steel costs for casing and other well equipment and oil field services. Future partnerships will be drilled on a "cost-plus basis," which should reduce these fluctuations in drilling gross margins. See Note 1 to the consolidated financial statements.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of RNG, the Company's marketing subsidiary, increased for the year ended December 31, 2006, to $131.3 million compared to $121.1 million for the year ended December 31, 2005, an increase of approximately $10.2 million, or 8.4%. The increase was the result of a 9% increase in volumes sold at prices 17.2% lower than 2005 levels and significant unrealized gains on derivative transactions which amounted to approximately $12.3 million for the year ended December 31, 2006, compared to unrealized losses of $8.5 million for the year ended December 31, 2005.

The costs of gas marketing activities for the year ended December 31, 2006, were $130.2 million compared to $119.6 million for the year ended December 31, 2005, an increase of $10.6 million, or 8.9%. The increase was due to higher average volumes of natural gas purchased for resale and a significant increase in unrealized losses on derivative transactions, which amounted to approximately $11.9 million for the year ended December 31, 2006, compared to an unrealized gain of $8.3 million for the year ended December 31, 2005. Income before income taxes for the Company's natural gas marketing subsidiary increased from $1.7 million for the year ended December 31, 2005, to $1.8 million for the year ended December 31, 2006. Based on the nature of the Company's gas marketing activities, derivatives did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the year ended December 31, 2006, were $115.2 million compared to $102.6 million for the year ended December 31, 2005, an increase of $12.6 million, or 12.3%. The increase was due to a 24% increase in volumes sold at lower average sales prices of natural gas and, in part, to higher average sales prices and higher volumes sold of oil. The volume of natural gas sold for the year ended December 31, 2006, was 13.2 Bcf at an average price of $5.91 per Mcf compared to 11.0 Bcf at an average sales price of $7.29 per Mcf for the year ended December 31, 2005. Oil sales for the year ended December 31, 2006, were 631,000 barrels at an average sales price of $59.33 per barrel compared to 439,000 barrels at an average sales price of $50.56 per barrel for the year ended December 31, 2005. The increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily the increase in net wells drilled for the Company's own account, recompletions of existing wells, and the investment in oil and gas properties it owns in drilling program partnerships.

Oil and Gas Production

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

	Year Ended December 31, 2006			Year Ended December 31, 2005		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Region	1,837	1,451,729	1,462,751	3,973	1,631,552	1,655,390
Michigan Region	4,439	1,399,852	1,426,486	4,732	1,555,958	1,584,350
Rocky Mountain Region	625,119	10,309,203	14,059,917	430,266	7,843,250	10,424,846
Total	631,395	13,160,784	16,949,154	438,971	11,030,760	13,664,586
Average Sales Price	$ 59.33	$ 5.91	$ 6.80	$ 50.56	$ 7.29	$ 7.51

*Six Bbl equals one Mcfe

Financial results depend upon many factors, particularly the price of natural gas and the Company's ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company's financial results. Natural gas and oil prices also vary by region, and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets can entail a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction which will help to maintain a balance between supply and demand. However, there may be times in which there may be oversupply situations for short or longer terms, which may affect the amount of gas or oil that the Company can sell, and the price at which it sells gas or oil. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, so their timing is not within its control.

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas prices, the Company has used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2008, the Company has in place a series of floors and ceilings associated with part of its natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, the Company pays the counterparty; however, if the index drops below the floor, the counterparty pays us. During the three months ended December 31, 2006, the Company averaged natural gas volumes sold of 1,283,000 Mcf per month and oil sales of 52,000 barrels per month. The positions in effect as of May 10, 2007, on the Company's share of production (the table below does not include positions related to RNG activities or derivative contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner) by area are shown in the following table.

		Floors		Ceilings	
Month Set	Months Covered	Monthly Quantity Gas-MMbtu Oil-Bbls	Contract Price	Monthly Quantity MMbtu	Contract Price
Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)					
Feb-06	May 2007 – Oct 2007	44,000	$ 5.50	-	$ -
Sep-06	May 2007 – Oct 2007	194,500	4.50	-	-
Dec-06	Nov 2007 – Mar 2008	100,000	5.25	-	-
Jan-07	Nov 2007 – Mar 2008	100,000	5.25	100,000	9.80
May-07	Apr 2008 – Oct 2008	197,250	5.50	197,250	10.35
NYMEX Based Hedges - (Appalachian and Michigan Basins)					
Feb-06	May 2007 – Oct 2007	85,000	7.00	-	-
Feb-06	May 2007 – Oct 2007	85,000	7.50	34,000	10.83
Sep-06	May 2007 – Oct 2007	85,000	6.25	-	-
Jan-07	May 2007 – Oct 2007	85,000	5.25	-	-
Dec-06	Nov 2007 – Mar 2008	144,500	7.00	-	-
Jan-07	Nov 2007 – Mar 2008	144,500	7.00	153,000	13.70
Jan-07	Apr 2008 – Oct 2008	144,500	6.50	153,000	10.80
Panhandle Based Hedges (NECO)					
Feb-06	May 2007 – Oct 2007	60,000	6.00	-	-
Feb-06	May 2007 – Oct 2007	60,000	6.50	60,000	9.80
Jan-07	May 2007 – Oct 2007	90,000	4.50	-	-
Dec-06	Nov 2007 – Mar 2008	70,000	5.75	-	-
Jan-07	Nov 2007 – Mar 2008	90,000	6.00	90,000	11.25
Jan-07	Apr 2008 – Oct 2008	90,000	5.50	90,000	9.85
DJ Basin					
Jan-07	May 2007 – Oct 2007	161,000	4.00	-	-
Jan-07	Nov 2007 – Mar 2008	90,000	5.25	90,000	9.80
May-07	Apr 2008 – Oct 2008	216,000	5.50	216,000	10.35
DJ Basin EXCO Property Acquisition					
Jan-07	May 2007 – Oct 2007	60,000	4.00	-	-
Jan-07	Nov 2007 – Mar 2008	30,000	5.25	30,000	9.80
May-07	Apr 2008 – Oct 2008	90,000	5.50	90,000	10.35
Oil – NYMEX Based (Wattenberg/ND)					
Sep-06	May 2007 – Oct 2007	12,350	50.00	-	-

Well Operations and Pipeline Income

Well operations and pipeline income for the year ended December 31, 2006, were $10.7 million compared to $8.8 million for the year ended December 31, 2005, an increase of approximately $1.9 million, or 21.6%. The increase was due to an increase in the number of wells and pipeline systems operated by the Company for drilling partnerships, as well as for third parties.

Oil and Gas Price Risk Management Gains (Losses), Net

Oil and gas price risk management gains (losses), net for the year ended December 31, 2006, was an aggregate gain of $9.1 million compared to a loss of approximately $9.4 million for the year ended December 31, 2005, a favorable change of $18.5 million. For the year ended December 31, 2006, the Company recorded realized gains of $1.9 million and unrealized gains of $7.2 million compared to the year ended December 31, 2005, which is comprised of unrealized losses of $3 million and realized losses of $6.4 million. The Company's strategy is to provide protection in the event of declining oil and natural gas prices. During 2006, the Company experienced decreasing natural gas and rising oil pricing environments. This trend and the timing, extent and nature of the derivative trades executed caused the Company to record gains in its derivative transactions as a result of gains on the natural gas positions. Oil and gas price risk management gains (losses), net is comprised of the change in fair value of oil and natural gas derivatives related to oil and gas production (this line item does not include commodity-based derivative transactions related to transactions from gas marketing activities, which are included in the revenues and expenses of the related purchase and sales transactions).

Other Income

Other income, consisting primarily of management fees associated with Company-sponsored drilling programs, was relatively unchanged at $2.2 million for each of the years ended December 31, 2006 and 2005.

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the year ended December 31, 2006, were $29.0 million compared to $20.4 million for the year ended December 31, 2005, an increase of approximately $8.6 million, or 42.2%. The increase was due to the increased production costs associated with the 24% increase in production volumes, along with the increased number of wells and pipelines operated by the Company. Lifting costs per Mcfe increased from $1.19 per Mcfe for the year ended December 31, 2005, to $1.23 per Mcfe for the year ended December 31, 2006, due to the significant inflation of oil field production services along with additional well workovers and production enhancements work performed.

Exploration Cost

The Company's exploration cost for December 31, 2006, decreased $3 million from $11.1 million for the same period last year to $8.1 million. The decrease is primarily attributable to fewer exploratory dry holes being drilled in 2006. In 2006, exploratory dry hole expenses were $1.8 million compared to $11.1 million in 2005. In 2006, the Company recorded an impairment charge of $1.5 million on its Nesson Field in North Dakota and incurred geological and geophysical costs of $2.2 million which relate to an exploratory seismic program initiated on the Company's Northeast Colorado properties. The Company anticipates additional geological and geophysical activities and related costs in 2007.

General and Administrative Expense

General and administrative expense for the year ended December 31, 2006, increased to $19 million compared to $7 million for the year ended December 31, 2005, an increase of approximately $12 million, or 171.4%. A substantial portion of the increase was attributable to the costs of the Company's financial statement restatement and the restatement of the Company-sponsored partnerships' financial statements. In addition, the Company continues to experience a high level of costs complying with the various provisions of Sarbanes-Oxley, in particular Section 404 (internal and external costs of assessing Internal Controls over Financial Reporting). Approximately $3.2 million of the increase is attributable to the external costs incurred in connection with restatement of financial statements and compliance with the provisions of Sarbanes-Oxley. Finally, the Company added over 39 new employees in 2006 and experienced increased payroll and payroll-related costs of $4.3 million.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the year ended December 31, 2006, increased to $33.7 million from approximately $21.1 million for the year ended December 31, 2005, an increase of approximately $12.6 million, or 59.7%. The increase was due to the 24% increase in production volumes, significant investments in oil and gas properties by the Company in 2006, and increased per unit cost of depreciation, depletion and amortization as a result of rising costs of drilling, completing and equipping wells.

Gain on Sale of Leaseholds

Gain on sale of leaseholds for the year ended December 31, 2006, was $328 million compared to $7.7 million in 2005, an increase of $320.3 million. The increase is attributable to the sale of undeveloped leaseholds in Garfield County, Colorado in the third quarter of 2006, for which a portion of the gain to be recognized was deferred to future periods. See Note 15 to consolidated financial statements. The prior year period included a gain of $6.2 million for the sale of a portion of one of the Company's undeveloped leases in Garfield County, Colorado and a gain of $1.5 million for the sale to an unaffiliated party of some Pennsylvania wells.

Interest Income

For the year ended December 31, 2006, interest income increased $7.2 million to $8.1 million compared to $0.9 million for the prior year period. The increase was primarily due to the interest income on the temporary investment, in cash equivalents, of cash proceeds of $353.6 million from the sale of undeveloped leaseholds.

Interest Expense

Interest expense for the year ended December 31, 2006, was $2.4 compared to $0.2 million for the year ended December 31, 2005, an increase of $2.2 million. The increase in interest expense was due to rising interest rates on significantly higher average outstanding balances of the credit facility, offset in part by $1.6 million of capitalized construction period interest. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of borrowing. The average outstanding debt balance for the year ended December 31, 2006, was $44.2 million compared to $4.1 million for the year ended December 31, 2005.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from 37.3% for the year ended December 31, 2005, to 38.6% for the year ended December 31, 2006, primarily as a result of the gain on sale of leasehold being taxed at the full federal and state statutory rates because there are no offsetting permanent deductions, such as percentage depletion, available on such a sale. In addition, the domestic production activities deduction was not utilized in 2006 due to the Company's decision, for tax purposes only, to expense the majority of its intangible drilling costs.

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

Revenues

Total revenues for the year ended December 31, 2005, were $325.2 million compared to $264.5 million for the year ended December 31, 2004, an increase of approximately $60.7 million, or 22.9%. The increase was a result of increased drilling revenues, gas sales from natural gas marketing activities, oil and gas sales, well operations and pipeline income, and other income partially offset by increased oil and gas price risk management losses.

Costs and Expenses

Total costs and expenses for the year ended December 31, 2005, were $267.4 million compared to $211 million for the year ended December 31, 2004, an increase of approximately $56.4 million or 26.7%. The increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production and well operations cost, exploration costs, general and administrative expenses and depreciation, depletion and amortization.

Drilling Operations

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

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

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

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of RNG, the Company's marketing subsidiary for the year ended December 31, 2005, were $121.1 million compared to $94.6 million for the year ended December 31, 2004, an increase of approximately $26.5 million or 28.0%. The increase was the result of significantly higher average natural gas sales prices and higher volumes sold offset in part by an increase in unrealized losses on derivative transactions which amounted to approximately $8.5 million in 2005 compared to unrealized gains of $1.2 million in 2004.

The costs of gas marketing activities for the year ended December 31, 2005, were $119.6 million compared to $92.9 million for the year ended December 31, 2004, an increase of $26.7 million or 28.7%. The increase was due to higher average volumes of natural gas purchased for resale and significantly higher average purchase prices offset in part by an increase in unrealized gains on derivative transactions which amounted to approximately $8.3 million in 2005 compared to unrealized losses of $0.8 million in 2004. Income before income taxes for the Company's natural gas marketing subsidiary decreased from $1.8 million for the year ended December 31, 2004, to $1.7 million for the year ended December 31, 2005. Based on the nature of the Company's gas marketing activities, derivatives did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the year ended December 31, 2005, were $102.6 million compared to $69.5 million for the year ended December 31, 2004, an increase of $33.1 million or 47.6%. The increase was due to higher volumes sold at significantly higher average sales prices of oil and natural gas. The volume of natural gas sold for the year ended December 31, 2005, was 11 million Mcf at an average price of $7.29 per Mcf compared to 10.4 million Mcf at an average sales price of $5.30 per Mcf for the year ended December 31, 2004. Oil sales for the year ended December 31, 2005, were 439,000 barrels at an average sales price of $50.56 per barrel compared to 381,000 barrels at an average sales price of $38.00 per barrel for the year ended December 31, 2004. The increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, wells drilled in the NECO, Colorado area of operation, and the investment in oil and gas properties the Company owns in the public drilling program partnerships.

Oil and Gas Production

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

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

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

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas prices the Company has used various derivative instruments to manage some of the impact of fluctuations in prices. At April 30, 2006, the Company had in place, through October 2007, a series of floors and ceilings on part of natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, the Company pays the counterparty, however if the index drops below the floor the counterparty pays us. During the three months ended December 31, 2005, the Company averaged natural gas volumes sold of 973,700 Mcf per month and oil sales of 36,050 barrels per month. The positions in effect as of April 30, 2006, on the Company's share of production (the table below does not include positions related to Riley Marketing activities or derivative contracts entered into by the Company on behalf of the affiliate Partnerships as the Managing General Partner) by area are shown in the following table.

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

Well Operations and Pipeline Income

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

Oil and Gas Price Risk Management Losses, Net

Oil and gas price risk management loss, net for the year ended December 31, 2005, was $9.4 million compared to approximately $3.1 million for the year ended December 31, 2004, an increase of $6.3 million. For the year ended December 31, 2005, the Company recorded unrealized losses of $3 million and realized losses of $6.4 million compared to the year ended December 31, 2004, which is comprised of unrealized losses of $1.5 million and realized losses of $1.6 million. The Company's strategy in its derivative policy is to provide protection on declining oil and natural gas prices. During 2005, the Company experienced rising oil and natural gas pricing environment, this trend caused the Company to record losses in its derivative transactions. In a declining oil and natural gas pricing environment the Company would, in theory, record gains in its derivative transaction activities. Oil and gas price risk management losses, net is comprised of the change in fair value of oil and natural gas derivatives related to oil and gas production (this line item does not include commodity based derivative transactions related to transactions from marketing activities).

Other Income

Other income for the year ended December 31, 2005, was $2.2 million compared to $1.7 million for the year ended December 31, 2004, an increase of $0.5 million.

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the year ended December 31, 2005, were $20.4 million compared to $17.7 million for the year ended December 31, 2004, an increase of approximately $2.7 million or 15.3%. The increase was due to the increased production costs and severance and property taxes on the increased volumes and higher average sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting costs per Mcfe increased from a restated $1.12 per Mcf for the year ended December 31, 2004, to $1.19 per Mcfe for the year ended December 31, 2005, due to increased severance and property taxes on the significantly increased oil and gas sales prices along with additional well workovers and production enhancements work performed.

Exploration Costs

The Company drilled eight exploratory wells in 2005 of which five were deemed to be dry holes. In the fourth quarter of 2005, four Kansas wells were drilled, plugged and abandoned for a total combined cost of $0.3 million, including lease acreage cost of $0.1 million, was expensed due to impairment. Also in the fourth quarter, the Coffeepot Springs #24-34 well in Colorado was determined to be uneconomical at a total dry hole cost of approximately $5.4 million, including lease acreage cost of $0.1 million, and expensed due to impairment. In the second quarter of 2005, it was determined the Fox Federal #1-13 well, which was drilled in 2004 in Colorado, was also an uneconomic well and total costs of approximately $5.4 million, including lease acreage cost of $0.4 million, was expensed due to impairment. These exploratory dry hole expenses were expensed in the period in which it was determined that the well was unsuccessful in accordance with the successful efforts method of accounting. All costs were incurred 100% by the Company because the drilling fund partnerships did not participate in these exploratory wells.

General and Administrative Costs

General and administrative expenses for the year ended December 31, 2005, increased to $7 million compared to $4.5 million for the year ended December 31, 2004, an increase of approximately $2.5 million or 55.6%. The increase was primarily due to increased costs of complying with the various provisions of Sarbanes-Oxley, in particular Section 404 (Internal Controls), the cost of the Company's financial statement restatements and increased personnel costs for the increased number of employees.

Depreciation, Depletion, and Amortization

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

Gain on Sale of Leaseholds

For the year ended December 31, 2005, the Company recognized a gain on sale of leaseholds totaling $7.7 million, $6.2 million for the sale to an unaffiliated entity of undeveloped leases in Garfield County, Colorado and $1.5 million for the sale to an unaffiliated party of some Pennsylvania wells. The Company recognized no gains on the sale of leaseholds in 2004.

Interest Income

The increase in interest income from 2004 to 2005 of approximately $0.7 was primarily attributable to higher average cash balances and higher interest rates.

Interest Expense

Interest expense was relatively unchanged for the year ended December 31, 2005, compared the year ended December 31, 2004. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of borrowing. The average outstanding debt balances for the year ended December 31, 2005, was $4.1 million compared to $11.3 million for the year ended December 31, 2004.

Provision for Income Taxes

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

Liquidity and Capital Resources

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

In July 2006, the Company sold to an unaffiliated company a portion of its undeveloped leaseholds in Grand Valley Field, Colorado, for cash proceeds of $353.6 million. Proceeds in the amount of $300 million were transferred to a qualified intermediary to be held in trust pursuant to the terms of a "like-kind exchange" agreement. In January 2007, the Company acquired, in accordance with the "like-kind exchange" agreement, oil and gas properties totaling $191.5 million. Following the payment of approximately $20 million in federal taxes, the Company will have available approximately $90 million in cash to fund 2007 drilling activities. Approximately $18.6 million, including direct costs of the acquisition, of the non-designated proceeds was utilized in 2006 to fund the acquisition of Unioil. The remaining unused portion of the like-kind funds were utilized to purchase a variety of other oil and gas properties and to pay down the outstanding balance of the Company's credit facility.

Natural Gas Pricing and Pipeline Capacity

The Company sells natural gas under contracts that are priced based on spot prices or price indexes that reflect current market prices for the commodity. As a result, variations in the market are reflected in the revenue the Company receives. The price of natural gas has varied substantially over short periods of time in the past, and there is every reason to expect a continuation of that variability in the future. During 2006, prices for natural gas decreased from the last part of 2005 but were still close to record levels, and future expectations as reflected in NYMEX futures market are for continuing high price levels for 2007 and beyond. Strong domestic and international demand for energy and inadequate short term supplies are believed to be key causes of the strong prices. High prices could encourage the development of new energy sources and reduced consumption as users find more efficient ways to use energy or substitute other energy forms. High energy prices could also slow global economic growth, further reducing demand. As a result, the energy price outlook could change rapidly from current expectations. Reduced natural gas prices would reduce the profitability and cash flow from the Company's gas production operations.

Financial results depend upon many factors, particularly the price of natural gas and the Company’s ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company’s financial results. Natural gas and oil prices also vary by region, and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain region. The combination of increased drilling activity and the lack of local markets can entail a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction which would help to maintain a balance between supply and demand. However, there may be times in which oversupply situations occur for short or longer terms, which may affect the amount of gas or oil that the Company can sell, and the price at which it sells gas or oil. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, so their timing is not within its control.

Oil Pricing

Oil prices were near or above record levels for most of 2005 and continued through 2006. The Company's oil prices are largely determined by oil prices in the world market. Global supply and demand and geopolitical factors are the key determinants of oil prices. The rapid growth of energy use in developing countries, most notably China, is driving a rapid increase in worldwide oil consumption. Higher prices could result in reduced consumption and/or increasing supplies that could moderate the current high price levels. Over the past several years, oil has been an increasing part of the Company's production mix. As a result, higher oil prices have contributed to the Company's increased revenue from oil and gas sales more than in the past, and the Company would suffer a greater impact if oil prices were to decrease. Oil sales accounted for 33% of the Company's oil and gas sales during 2006 compared to 21.6% in 2005.

Oil and Gas Derivative Activities

Because of the uncertainty surrounding natural gas and oil prices, the Company has used various derivative instruments to manage some of the impact of fluctuations in prices. The Company has in place a series of floors and ceilings on part of natural gas and oil production, which extend through October 2008. Under the arrangements, if the applicable index rises above the ceiling price, the Company pays the counterparty; however, if the index drops below the floor, the counterparty pays the Company. See the section titled "Oil and Gas Derivative Activities" as discussed in results of operations for a more detailed analysis of the Company's current derivative positions.

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

The Company’s derivative transactions do not currently qualify for hedge accounting under SFAS No. 133. Therefore, the Company records its derivative gains and losses, both realized and unrealized, through oil and gas price risk management for its share of production. The Company is required to mark-to-market its derivative positions at the end of each period and record the adjustment to the consolidated statement of income under oil and gas price risk management. This may and does cause wide variability in profits from period to period. In 2005, the Company's recognized oil and gas price risk management losses, net of $9.4 million compared to oil and gas price risk management gains, net of $9.1 million in 2006.

Drilling Programs

On September 1, 2006, the Company funded its 2006 partnership, Rockies Region 2006 Limited Partnership, with subscriptions of approximately $90 million. Upon closing on September 1, 2006, the Company, as managing general partner, contributed in cash a total of $38.9 million for its contribution to the total capital of the partnership. After payment of sales commissions and associated expenses, including a management fee of $1.3 million to the Company, the partnership had a total of approximately $118 million available for future drilling. Drilling operations commenced on September 1, 2006, and will continue through the first quarter of 2007. All of the 2006 partnership's 97 wells have been drilled as of March 31, 2007.

The Company invests, as its equity contribution to each drilling partnership, a sum equal to approximately 43% of the aggregate subscriptions received in the current drilling partnership being offered. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

Substantially all of the Company's drilling programs contain a provision allowing investors to request that the Company purchase their partnership units. This provision is in effect any time beginning with the third anniversary of the first cash distribution. If investors request that the Company repurchase their units, the provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), subject to the Company's financial ability to do so. The maximum annual 10% purchase obligation, if requested by the investors, is currently approximately $12.3 million. The Company has adequate liquidity to meet this obligation. During 2006, the Company spent $0.8 million acquiring additional partnership interests under this provision. As of December 31, 2006, pursuant to this provision, outstanding purchase offers to investing partners totaled $0.2 million. In 2007, $0.1 million of such outstanding offers were consummated prior to their expiration on or before February 28, 2007.

Drilling Activity

During 2006, the Company, for its own account and on behalf of its drilling fund partnerships, drilled a total of 118 wells with one developmental dry hole. The Company drilled 81 successful wells in its Wattenberg Field in the Denver-Julesburg Basin and 30 successful wells in the Piceance Basin in western Colorado. Also in 2006, the Company and its drilling fund partnerships drilled four wells in North Dakota.

During 2006, the Company drilled several development wells outside of the drilling fund partnerships. The Company drilled 34 wells on its northeast Colorado properties and participated in 10 additional wells which were drilled by joint venture partners. Of these 44 wells, 41 were successful. The Company also drilled 41 Wattenberg Field wells and 19 Piceance Basin wells for its own account, of which 58 were successful. The Company also drilled a successful developmental gas well in the Michigan Basin. In North Dakota, the Company and other joint venture partners drilled one successful development well.

In 2006, the Company included its drilling fund partnerships in its exploratory well drilling activities by drilling two such wells within the parameters of the partnership. One well in Wyoming was classified as dry and expensed in accordance with the successful efforts method of accounting while the other well drilled in North Dakota was successful. The Company drilled for its own benefit one well in North Dakota, as well as participated with other joint venture partners, outside of the partnerships, in the drilling of six exploratory wells also in North Dakota, all of which were considered successful.

The company incurred exploratory dry hole costs of $1.8 million for the year ended 2006, of which $1.3 million was from one well drilled in Wyoming. The remaining $0.5 million of expenses were incurred on wells previously classified as dry holes in 2005.

Costs of Oil and Gas Properties

Costs incurred by the Company in oil and gas property acquisition, exploration and development for the year ended December 31, 2006, are presented below (in thousands):

Acquisition of properties:		
Unproved properties	$	11,926
Proved properties		802
Development costs		114,487
Exploration costs		20,894
Total costs incurred	$	148,109

Treasury Share Purchases

On January 13, 2006, the Company announced that its Board of Directors had authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that management deemed appropriate. In October 2006, the Company completed its January 2006 program. Total shares purchased pursuant to the program were 1,627,500 common shares at a cost of $66.3 million ($40.75 average price paid per share), including 100,000 shares from an executive officer of the Company at a cost of $4.1 million ($40.66 price paid per share). All shares purchased in accordance with the program have subsequently been retired.

On October 16, 2006, the Board of Directors of the Company approved a second 2006 purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time.

Working Capital

The Company's working capital as of December 31, 2006, is $29.2 million. The Company manages its working capital needs by only drawing from its credit facility of $200 million as liabilities come due and cash is required. At December 31, 2006, the Company had an activated line of credit with an additional borrowing capacity, in excess of amounts outstanding, of $18 million.

As of December 31, 2006, the Company had $300 million of cash in a "like-kind exchange" trust, of which $109 million is classified in the consolidated balance sheet as cash and the remaining $191.5 million is classified as designated cash, a non-current asset, as it represents the amount subsequently qualifying for "like-kind exchange" treatment and used for the acquisition of oil and gas properties completed in January 2007. At December 31, 2006, the Company has adequate liquidity when considering these funds along with the credit facility to meet both its working capital requirements and plans for continued investment in oil and gas well drilling over the next year.

Long-Term Debt

The Company has a credit facility with JPMorgan Chase Bank, N.A. and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. The current borrowing base, based upon oil and gas reserves, is $135 million. The Company is required to pay a commitment fee of 0.25 to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an Alternative Base Rate, as defined in the credit facility or adjusted LIBOR ("London Interbank Market Rate") at the Company's discretion. No principal payments are required until the credit agreement expires on November 4, 2010. During March 2007, due to various reporting and processing delays, the Company requested a waiver related to the Security assignment provisions of its credit facility. During March 2007, the waiver was granted and the corresponding Borrowing Base was reduced to $100 million from $135 million. See Note 5 to the consolidated financial statements for further information.

On December 19, 2006, the Company executed pursuant to its credit facility a short-term, non-revolving overline note in the amount of $20 million to be repaid on or before January 31, 2007. The note was paid in full on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.80% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note is reflected on the consolidated balance sheet as a current liability.

As of December 31, 2006 and 2005, the outstanding balances under the facility, including the overline note, were $137 million and $24 million, respectively. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves and the maintenance of certain working capital and tangible net worth ratios. At December 31, 2006, an outstanding balance of $67 million was subject to a prime interest rate of 8.375%; the overline note in the amount of $20 million was subject to an interest rate of 9.05% and the remaining outstanding balance of $50 million was subject to a LIBOR rate of 7.0%. As previously discussed, the Company requested and was granted a waiver related to the Security provisions of its credit facility. Additionally, the Company requested and was granted a waiver related to the delay in the delivery of its consolidated financial statements for the year ended December 31, 2006, and three months ended March 31, 2007, until May 31, 2007, and June 30, 2007, respectively.

Contractual Obligations and Contingent Commitments

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

(in thousands)		Payments due by period			
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 117,000	$ -	$ -	$ 117,000	$ -
Operating Leases	2,049	502	988	555	4
Drilling Obligations (1)	28,725	11,125	17,600	-	-
Asset Retirement Obligations	11,966	100	200	200	11,466
Drilling Rig Commitments	36,054	12,556	21,635	1,863	-
Derivative Agreements (2)	2,545	2,545	-	-	-
Other Liabilities	10,371	40	702	4,011	5,618
Total	$ 208,710	$ 26,868	$ 41,125	$ 123,629	$ 17,088

(1) Represents the Company's obligations to drill. Failure to drill wells as specified in the related agreements will result in the Company having to pay liquidated damages. A total of $25.6 million is reflected on the consolidated balance sheet as a deferred gain on sale of leaseholds. See Note 12 to consolidated financial statements.

(2) Amounts represent gross liability related to fair value of derivatives. Includes fair values of derivatives for RNG and PDC's share of oil and gas production and derivative contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The Company has a corresponding receivable from the partnerships of $0.1 million as of December 31, 2006.

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

Commitments and Contingencies

As managing general partner of 76 partnerships (see Item 1. Business – Drilling and Development), the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. In January 2007, the Company purchased the remaining working interests in 44 of the 76 partnerships, which were sponsored by the Company in the late 1980s and 1990s (see Note 16 to the consolidated financial statements). The Company's management believes its and its subcontractors' casualty insurance coverage is adequate to meet this potential obligation.

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

Recent litigation has commenced against several companies in our industry regarding royalty practices and payments in jurisdictions where the Company conducts business. While the Company's business model differs from those of the litigants in those cases, and the Company has not been named in any litigation, has not had similar litigation commenced, nor has such litigation been threatened, there can be no assurance that the Company will not be a party to any litigation or to similar litigation in the future.

Sale of Undeveloped Leaseholds

In July 2006, the Company sold to Marathon Oil Company, an unaffiliated company, a portion of its undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. The sale encompassed 100% of the working interest in approximately 8,700 acres, including approximately 6,400 acres of the Company's Chevron leasehold and 2,300 acres of the Company's Puckett Land Company leasehold. The Company retained approximately 475 undeveloped locations on 10 acre spacing on the Grand Valley Field leasehold in addition to all of its producing properties in the field. The proceeds from the sale were $353.6 million.

The Company recorded a gain on sale of leaseholds of $328 million and a deferred gain on sale of leaseholds of $25.6 million. The Company is obligated to either drill 16 wells on specifically identified acreage over the next three years (five by December 31, 2007, another five by December 31, 2008, and another six by December 31, 2009) or pay liquidated damages of $1.6 million per un-drilled well. The Company expects to drill the wells for its own benefit and, as such, will record the costs of the wells drilled in accordance with its oil and gas properties accounting policy. For each well the Company drills, the Company will recognize $1.6 million of the deferred gain when drilling is complete. Alternatively, should the Company not first drill the wells, the unaffiliated company has the option to drill the wells for its benefit and, should it decide to exercise its option, with each well drilled, the Company would recognize both $1.6 million of the amount deferred and $0.4 million to be paid to the Company by the unaffiliated company. At December 31, 2006, $8 million of the deferred gain on sale of leaseholds is classified as short-term and included in other current liabilities in the accompanying consolidated balance sheet.

In conjunction with the sale, the Company entered into a "like-kind exchange" ("LKE") agreement, in accordance with Section 1031 of the Internal Revenue Code, with a "qualified intermediary." Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. The Company had until mid-January 2007 to close any acquisition of suitable like-kind property, allowing the Company to take advantage of the income tax deferral benefits of a LKE transaction. See below a discussion of the acquisition of suitable like-kind properties.

Acquisition of Oil and Gas Properties

Unioil

On December 6, 2006, the Company completed its cash tender offer and purchased approximately 95.5%, or 9,112,750 shares, of the outstanding common stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The acquisition of more than 90% of the outstanding shares of common stock allowed the Company to effect a short-form merger of Unioil and a wholly owned subsidiary of the Company, resulting in the acquisition of the remaining 428,719 shares of Unioil. Each share of Unioil common stock not tendered through the offer was converted into the right to receive $1.91 in cash, the same consideration paid for shares in the tender offer. The total price paid for 100% of Unioil's outstanding common stock was $18.6 million, including $0.4 million in direct costs of the acquisition. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, *Business Combinations*.

Acquisition of Section 1031 – LKE Properties

In January 2007, the Company completed its acquisitions of suitable like-kind properties in accordance with the LKE agreement it entered into in connection with its sale of undeveloped leaseholds located in Grand Valley Field, Garfield Country, Colorado in July 2006. The Company paid cash consideration for the acquired oil and gas properties totaling $191.5 million, as described below.

EXCO Resources Inc. On January 5, 2007, the Company completed its purchase of EXCO Resources Inc.'s producing properties and remaining undeveloped drilling locations and acreage in the Wattenberg Field area of the DJ Basin, Colorado. The cash consideration paid for the EXCO properties was $130.9 million. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 oil and gas wells (approximating 25.5 Bcfe, net of royalty interests, proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. The Company will operate the assets and holds a majority working interest in the properties.

Company-Sponsored Partnerships. On January 10, 2007, the Company completed the purchase of a majority interest in 44 Company-sponsored partnerships for $58.8 million. This transaction was not effected pursuant to purchase requests by investor partners (see "Drilling Programs"). The wells are located in the Appalachian Basin, Michigan, and Colorado. The transaction resulted in an increase in the Company's net interest in 718 wells that are currently operated by the Company.

Other. The Company acquired from unaffiliated parties undeveloped leaseholds in Erath County, Texas for $1.8 million.

Other Acquisitions

On February 22, 2007, the Company acquired from an unaffiliated party 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $11.8 million. The acquisition encompasses current daily production of approximately 668 Mcfe (520 Mcf of gas and 25 barrels of oil per day), net to the interests acquired, 100 or more undeveloped drilling locations, 19.1 Bcfe of proved reserves, and an additional 7.5 Bcfe of probable reserves.

Critical Accounting Policies and Estimates

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

Principles of Consolidation

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

Revenue Recognition

The Company's drilling segment recognizes revenue from drilling contracts with sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. In addition, the Company offers its drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships and consequently, different revenue reporting policies pursuant to Emerging Issues Task Force ("EITF") No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*.

The first cost-plus drilling service arrangement was entered into in late 2005, with drilling activity commencing in the first quarter of 2006. Although the Company acts overall as a principal in the transaction and takes title to products and services acquired necessary for drilling, the Company acts as an agent, with little risk of loss during the performance of the drilling activities. Consistent with the provisions of EITF 99-19, the Company's services provided under the cost-plus drilling agreements are reported net of recovered costs. The Company entered into its second cost-plus drilling arrangement in September 2006 and commenced drilling immediately. It is the Company's intent that all future drilling arrangements will be on a cost-plus basis.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are generally completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services at a fixed footage-based rate and accordingly has risk of loss in performing services under these arrangements. Accordingly, the Company reports revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that the estimated total costs exceed the estimated total contract revenue. At December 31, 2006 and 2005, the loss contract reserve was $0.3 million and $0.8 million, respectively.

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

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

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

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

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

Valuation of Accounts Receivable

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

Accounting for Derivatives Contracts at Fair Value

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

Derivatives are reported on the consolidated balance sheets at fair value. Changes in fair value of derivatives are recorded in earnings in the consolidated statements of income as none of the Company's derivatives qualified for hedge accounting under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

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

Use of Estimates in Long-Lived Asset Impairment Testing

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

Oil and Gas Properties

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

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

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

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

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

Deferred Income Tax Asset Valuation Allowance

Deferred income tax assets are recognized for deductible temporary differences, net operating loss carry-forwards, and credit carry-forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset is not expected to be realized under the preceding criteria, a valuation allowance has been established. The factors which the Company considers in assessing whether or not it will realize the value of deferred income tax assets involve judgments and estimates of both amount and timing, which could differ from actual results achieved in future periods.

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

Evaluation of Errors

The Company has historically utilized the "roll-over" method, by which only the current period effect is considered, of assessing the materiality of misstatements. In 2006, the Company became subject to the provisions of SEC Staff Accounting Bulletin ("SAB") No. 108, and now utilizes the dual method of assessing materiality - both "roll-over" and "iron curtain" methods, by which the full reversing effect of cumulative errors is considered each period.

Recent Accounting Standards

See Note 1, *Summary of Significant Accounting Policies - Recent Accounting Standards*, to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK.

Market-Sensitive Instruments and Risk Management

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

Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents, designated cash and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, short-term certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of December 31, 2006, is $405.1 million with an average interest rate of 4.9%. As of December 31, 2006, the Company had long-term debt of $117 million subject to a prime interest rate of 8.375%. As of December 31, 2006, the outstanding balance under the facility, including the overline note, was $137 million, of which the overline note in the amount of $20 million was subject to an interest rate of 9.05%, $67 million was subject to an Alternative Base Rate, as defined in the credit facility, of 8.375% and the remaining outstanding balance of $50 million was subject to LIBOR of 7.0%.

Commodity Price Risk

Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company's financial results. Natural gas and oil prices also vary by region, and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain region. The combination of increased drilling activity and the lack of local markets can create a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction which will help to maintain a balance between supply and demand. However, oversupply situations may occur from time to time, which may affect the quantity of and price at which the Company can sell its oil and gas. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, so their timing is not within the Company's control.

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

The following tables summarize the open derivative and fixed-price purchase and sale contracts for RNG and PDC as of December 31, 2006 and 2005.

Riley Natural Gas

Open Derivative Positions

(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Futures/Swaps Purchases	246,900	$ 7.34	$ 1,811	$ (304)
Natural Gas	Cash Settled Futures/Swaps Sales	1,952,150	8.42	16,444	2,815
Natural Gas	Cash Settled Basis Swap Purchases	90,000	0.42	38	(12)
Natural Gas	Cash Settled Basis Swap Sales	20,000	0.50	10	4
Natural Gas	Cash Settled Option Purchases	220,000	5.50	1,210	64
Natural Gas	Cash Settled Option Sales	110,000	10.10	1,111	(39)
Natural Gas	Physical Purchases	1,964,150	8.27	16,244	(1,974)
Natural Gas	Physical Sales	114,974	9.62	1,106	310
Natural Gas	Physical Basis Purchases	20,000	0.45	9	(3)
Natural Gas	Physical Basis Sales	90,000	0.44	39	14
Positions maturing in 12 months following December 31, 2006					
Natural Gas	Cash Settled Futures/Swaps Purchases	246,900	$ 7.34	$ 1,811	$ (304)
Natural Gas	Cash Settled Futures/Swaps Sales	1,637,150	8.37	13,697	2,637
Natural Gas	Cash Settled Basis Swap Purchases	90,000	0.42	38	(12)
Natural Gas	Cash Settled Basis Swap Sales	20,000	0.50	10	4
Natural Gas	Cash Settled Option Purchases	220,000	5.50	1,210	64
Natural Gas	Cash Settled Option Sales	110,000	10.10	1,111	(39)
Natural Gas	Physical Purchases	1,649,150	8.27	13,641	(2,027)
Natural Gas	Physical Sales	114,974	9.62	1,105	310
Natural Gas	Physical Basis Purchases	20,000	0.45	9	(3)
Natural Gas	Physical Basis Sales	90,000	0.44	39	14
Prior Year Total Positions as of December 31, 2005					
Natural Gas	Cash Settled Futures/Swaps Purchases	1,025,500	$ 9.05	$ 9,283	$ 1,983
Natural Gas	Cash Settled Futures/Swaps Sales	3,149,000	7.95	25,018	(8,689)
Natural Gas	Cash Settled Basis Swap Purchases	450,000	0.91	409	(158)
Natural Gas	Cash Settled Basis Swap Sales	240,000	0.50	120	4
Natural Gas	Physical Purchases	2,819,000	8.32	23,456	7,858
Natural Gas	Physical Sales	585,222	10.72	6,272	(670)
Natural Gas	Physical Basis Purchases	240,000	0.45	108	8
Natural Gas	Physical Basis Sales	450,000	0.94	420	169

Petroleum Development Corporation
Open Derivative Positions
(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Option Sales	17,390,000	$ 5.56	$ 96,613	$ 12,597
Natural Gas	Cash Settled Option Purchases	2,155,000	10.34	22,287	(14)
Oil	Cash Settled Option Purchases	300,000	50.00	15,000	155
Positions maturing in 12 months following December 31, 2006					
Natural Gas	Cash Settled Option Sales	15,530,000	$ 5.53	$ 85,850	$ 11,682
Natural Gas	Cash Settled Option Purchases	2,155,000	10.34	22,287	(14)
Oil	Cash Settled Option Purchases	300,000	50.00	15,000	155
Prior Year Total Positions as of December 31, 2005					
Natural Gas	Cash Settled Option Sales	5,665,000	$ 8.17	$ 46,273	$ (12,531)
Natural Gas	Cash Settled Option Purchases	14,030,000	6.36	89,210	2,660

In addition to including the gross assets and liabilities related to the Company's share of oil and gas production, the above tables and the accompanying consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The accompanying consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of $7.5 million as of December 31, 2006, and a net receivable from the partnerships of $5.4 million as of December 31, 2005. In addition to the short-term fair value of derivatives shown on the accompanying consolidated balance sheets, there are long-term assets and long-term liabilities which total to a net long-term asset of approximately $0.9 million as of December 31, 2006, and which total a net long-term asset of approximately $1.3 million as of December 31, 2005, respectively, related to the fair value of derivatives included in accompanying balance sheets.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults during the years ended December 31, 2006, 2005 and 2004.

The average NYMEX closing prices for natural gas for the years 2006, 2005 and 2004, were $7.23 Mmbtu, $8.62 Mmbtu and $6.14 Mmbtu. The average NYMEX closing prices for oil for the years 2006, 2005 and 2004, were $64.73 bbl, $55.34 bbl and $41.44 bbl. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

Disclosure of Limitations

Because the information above incorporates only those exposures that exist at December 31, 2006, it does not consider those exposures or positions which could arise after that date. As a result, the Company's ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, the Company's hedging strategies at the time, and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Index to financial statements.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES

(1) Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the management of the Company, under the supervision and with the participation of the Company's Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the Company's disclosure controls and procedures as defined in Rule 13a-15(e) of the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2006, the Company's disclosure controls and procedures were not effective in enabling the Company to record, process, summarize and report, in a timely manner, the information that the Company is required to disclose in its Exchange Act reports due to the existence, at December 31, 2006, of three material weaknesses described below in section (2), "Management's Report on Internal Control over Financial Reporting ."

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based upon the criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, management concluded that three material weaknesses, which are control deficiencies, or combinations of control deficiencies, that result in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected, existed at December 31, 2006. The Company's assessment, as of December 31, 2006, identified the following material weaknesses:

- The Company did not have effective policies and procedures to ensure the timely reconciliation, review and adjustment of significant balance sheet and income statement accounts. As a result, material misstatements were identified during the Company's closing process in certain significant balance sheet and income statement accounts and corrected prior to the issuance of the Company's 2006 consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise to ensure proper accounting for derivative instruments. Specifically, the Company's internal control processes did not ensure the completeness of all derivative contracts related to oil and gas sales, and also did not ensure the determination of the fair value of certain derivatives. As a result, misstatements were identified in the fair value of derivatives and related income statement accounts and corrected prior to the issuance of the Company's 2006 consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures to ensure proper accounting for oil and gas properties. Specifically, the Company's review procedures were not sufficient to ensure that the calculations of depreciation and depletion were performed accurately and that the capitalization of costs was performed in accordance with the applicable authoritative accounting guidance. As a result, misstatements were identified in 2006 in depreciation, depletion and amortization expense, and corrected prior to the issuance of the Company's consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

Management has concluded that, as a result of the material weaknesses noted above, the Company did not maintain effective internal control over financial reporting as of December 31, 2006, based on criteria set forth in the COSO Framework.

The Company acquired Unioil on December 6, 2006, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, Unioil's internal control over financial reporting associated with total assets of $26.1 million and total revenues of $0.3 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2006.

The Company's independent registered public accounting firm, KPMG LLP, has issued an audit report on Management's assessment of the Company's internal control over financial reporting as of December 31, 2006, which is included in this annual report on Form 10-K

(3) Changes in Internal Control over Financial Reporting

Changes in Internal Control over Financial Reporting During the Quarter Ended December 31, 2006

There have been changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the most recent fiscal quarter that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

During the fourth quarter of 2006, management completed implementing, documented and tested internal control over financial reporting which, as noted below, have allowed management to conclude that there are no longer material weaknesses in its accounting for asset retirement obligations, proportionate consolidation and income taxes.

Status of December 31, 2005, Evaluation and Related Material Weaknesses in Internal Control Over Financial Reporting

In connection with the preparation of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 ("2005 10-K"), an evaluation was completed under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act). The Company concluded that, as of December 31, 2005, certain control deficiencies in its internal control over financial reporting constituted material weaknesses within the meaning of the Public Company Accounting Oversight Board's Auditing Standard No. 2. Specifically, deficiencies related to the Company's accounting for derivatives, oil and gas properties, asset retirement obligations, proportionate consolidation and income taxes were determined to be material weaknesses. Beginning in 2005 and throughout all four fiscal quarters of 2006, management undertook remediation efforts, described in further detail below, to address and remediate these material weaknesses, and ultimately remediated three of these material weaknesses.

The Company has evaluated remediation efforts initiated to address material weaknesses identified by the Company - and disclosed in its December 31, 2005, annual report on Form 10-K as part of management's evaluation of internal control over financial reporting, and in its March 31, June 30, and September 30, 2006, quarterly reports on Forms 10-Q, as part of its evaluation of disclosure controls and procedures in those periods. Based upon that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2006, the Company no longer has deficiencies in its internal control over financial reporting which represent material weaknesses in its accounting related to asset retirement obligations, proportionate consolidation and income taxes.

Remediation Efforts Undertaken to Address and Correct 2005 Material Weaknesses in Internal Control Over Financial Reporting

In order to address and remediate the above-mentioned December 31, 2005 material weaknesses, the following changes in the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting were made during the year ended December 31, 2006, ultimately resulting in management concluding that three of those material weaknesses have been corrected:

- In November 2006, the accounting and finance group was reorganized to include a new position of Chief Accounting Officer ("CAO"), which reports directly to the Chief Financial Officer. The CAO's responsibilities include the proper application of generally accepted accounting principles, and the supervision of the Company's Sarbanes-Oxley compliance program. Mr. Darwin Stump, CPA, formerly the Chief Financial Officer assumed the new position of CAO in November 2006.

- Concurrently, in November 2006, the Company appointed a new Chief Financial Officer and Treasurer, who has significant oil and gas industry and accounting experience. In addition to his finance responsibilities, the new Chief Financial Officer has assumed a leadership role in guiding the Company's Sarbanes-Oxley compliance program.

- Additional controls and procedures were designed by the Company during 2006 over the creation and reporting of the Company's income tax provision and accounting for other miscellaneous taxes. In addition, in December 2006, the Company hired a Director of Taxation with significant and relevant experience with another publicly held company, including the preparation and review of tax provisions, tax-related disclosures and footnotes for financial statement reports and SEC filings. These additional controls were tested as part of the Company's year end Sarbanes-Oxley compliance effort and were determined to be operating effectively by management.

- During 2006, the Company expanded the size of its financial accounting and reporting team by hiring professionals with significant and relevant experience. Specifically, an additional certified public accountant was hired in the first quarter of 2006 and two additional certified public accountants were hired during the second quarter of 2006, including a corporate financial reporting director, a partnership financial reporting director, and an exploration and production ("E&P") accountant.

- Continuing the process begun and reported during 2005, the Company enhanced its training program for its financial accounting and reporting team; formal training has been conducted during 2005 and 2006, including oil and gas accounting and other topics specific to the areas of the Company's internal control over financial reporting for which material weaknesses were reported as of December 31, 2005, and through all four quarters of 2006.

- Starting during the fourth quarter 2005 and continuing through 2006, the Company subscribed to online accounting research and other accounting technical resources including GAAP and SEC reporting checklists and has utilized these resources to assist in the preparation of its financial statements and SEC filings. Additionally, the online research tool has been used as a source of periodic informal training and education in supporting and enhancing the technical expertise of the financial accounting and reporting team. Company finance, accounting and financial reporting personnel have utilized these resources throughout 2006.

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

- During 2005 and continuing in 2006, the Company re-evaluated and improved its documentation, policies and procedures, and templates with respect to its accounting for derivatives, oil and gas property depreciation, depletion and amortization, proportionate consolidation, asset retirement obligations and income taxes, and the related disclosures in its financial statements. The corrected policies and procedures were employed by the Company in the preparation of each of its 2006 periodic financial statements on Form 10-Q, and in this annual report on Form 10-K. Senior management – both operating and financial reporting management – has played a significant role in performing appropriate and sufficient monitoring and review control activities focusing on the appropriate application of the correct policies and procedures in the Company's periodic financial reporting.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Petroleum Development Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting (Item 9A(2)), that Petroleum Development Corporation and subsidiaries (the Company) did not maintain effective internal control over financial reporting as of December 31, 2006 because of the effect of the material weaknesses identified in management's assessment based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. Management has identified and included in its assessment the following material weaknesses as of December 31, 2006:

- The Company did not have effective policies and procedures to ensure the timely reconciliation, review and adjustment of significant balance sheet and income statement accounts. As a result, material misstatements were identified during the Company's closing process in certain significant balance sheet and income statement accounts of the Company's 2006 consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise to ensure proper accounting for derivative instruments. Specifically, the Company's internal control processes did not ensure the completeness of all derivative contracts related to oil and gas sales, and also did not ensure the determination of the fair value of certain derivatives. As a result, misstatements were identified in the fair value of derivatives and related income statement accounts of the Company's 2006 consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures to ensure proper accounting for oil and gas properties. Specifically, the Company's review procedures were not sufficient to ensure that the calculations of depreciation and depletion were performed accurately and that the capitalization of costs was performed in accordance with the applicable authoritative accounting guidance. As a result, misstatements were identified in 2006 in depreciation, depletion and amortization expense of the Company's consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

In our opinion, management's assessment that Petroleum Development Corporation did not maintain effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, Petroleum Development Corporation did not maintain effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Company acquired Unioil on December 6, 2006, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, Unioil's internal control over financial reporting associated with total assets of $26.1 million and total revenues of $0.3 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2006. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Unioil.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2006. The aforementioned material weaknesses were considered in determining the nature, timing and extent of audit tests applied in our audit of the 2006 consolidated financial statements, and this report does not affect our report dated May 22, 2007, which expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP
Pittsburgh, Pennsylvania
May 22, 2007

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

Name	Age	Position(s)	Director Since	Directorship Term Expires
Steven R. Williams	56	Chairman, Chief Executive Officer and Director	1983	2009
Thomas E. Riley	54	President and Director	2004	2007
Richard W. McCullough	55	Chief Financial Officer and Treasurer	–	–
Darwin L. Stump	52	Chief Accounting Officer	–	–
Eric R. Stearns	49	Executive Vice President, Exploration and Production	–	–
Vincent F. D'Annunzio	54	Director	1989	2007
Jeffrey C. Swoveland	52	Director	1991	2008
Kimberly Luff Wakim	49	Director	2003	2009
David C. Parke	40	Director	2003	2008
Anthony J. Crisafio	54	Director	2006	2009

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

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

Richard W. McCullough was appointed Chief Financial Officer and Treasurer in November 2006. Prior to joining the Company, Mr. McCullough served as president and chief executive officer of Gasource, LLC, Dallas, Texas, a marketer of long-term, natural gas supplies. From 2001 to 2003, Mr. McCullough served as an investment banker with J.P. Morgan Securities, Atlanta, Georgia, and served in the public finance utility group supporting bankers nationally in all natural gas matters. Additionally, Mr. McCullough has held senior positions with Progress Energy, Deloitte and Touche, and the Municipal Gas Authority of Georgia. Mr. McCullough, a CPA, was a practicing certified public accountant for eight years.

Darwin L. Stump was appointed Chief Accounting Officer in November 2006. Mr. Stump has been an officer of the Company since April 1995 and held the position of Chief Financial Officer and Treasurer from 2003 until November 2006. Previously, Mr. Stump served as Corporate Controller from 1980 until November 2003. Mr. Stump, a CPA, was a senior accountant with Main Hurdman, Certified Public Accountants prior to joining the Company.

Eric R. Stearns was appointed Executive Vice President of Exploration and Production in December 2004. Prior to his current position, Mr. Stearns was Executive Vice President of Exploration and Development since November 2003, having previously served as Vice President of Exploration and Development since April 1995. Mr. Stearns joined the Company as a geologist in 1985 after working for Hywell, Incorporated and for Petroleum Consultants.

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, a life-science company specializing in the design and development of wearable body monitoring products and services, since September, 2000. Prior thereto, Mr. Swoveland held various positions, including vice president of finance, treasurer and interim chief financial officer, with Equitable Resources, Inc., a diversified natural gas company, from 1997 to September 2000. Mr. Swoveland serves as a member of the board of directors of Linn Energy, LLC, a public, independent natural gas and oil company.

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

David C. Parke is a managing director in the investment banking group of Boenning & Scattergood, Inc., West Conshohocken, Pennsylvania, a full-service investment banking firm. Prior to joining Boenning & Scattergood in November 2006, he was a director with Mufson Howe Hunter & Company LLC, Philadelphia, Pennsylvania, an investment banking firm, from October 2003 to November 2006. From 1992 through 2003, Mr. Parke was director of corporate finance 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., now part of Stifel Nicolaus. Mr. Parke serves as a member of the board of directors of Zunicom, Inc., a public company providing business communication services to the hospitality industry.

Anthony J. Crisafio was elected to the Board in October 2006. Mr. Crisafio, a certified public accountant, serves as an independent business consultant, providing financial and operational advice to businesses and has done so since 1995. He owned two small businesses during the period of 1991 to 2002. Additionally, Mr. Crisafio has served as the chief operating officer of Cinema World, Inc. from 1989 until 1993 and was a partner with Ernst & Young from 1986 until 1989.

Corporate Governance

In January 2005, the Company adopted Corporate Governance Guidelines to promote the effective functioning of its Board of Directors and related committees.

Board of Directors

The Company's By-Laws provide that the number of members of the Board of Directors ("Board") shall be designated from time to time by a resolution of the Board and, in absence of such designation, the number of directors shall be seven. The Board shall be divided into three separate classes of directors which are required to be as nearly equal in number as practicable. At each annual meeting of stockholders one class of directors, whose term expires, will be elected to a term of three years. The classes are staggered so that the term of one class expires each year. There is no family relationship between any director or executive officer and any other director or executive officer of the Company. There are no arrangements or understandings between any director or officer and any other person pursuant to which the person was selected as an officer.

Director Independence

The Company has determined that all of its directors, other than Messrs. Williams and Riley, are independent under NASDAQ Marketplace Rule 4200 and the Exchange Act.

Committees of the Board

The following table identifies the current membership and chair of the five standing committees of the Board:.

Name	Audit	Compensation	Executive	Nominating/ Corporate Governance	Planning/ Finance
Jeffrey C. Swoveland	Chair	–	Member	–	Member
Kimberly Luff Wakim	Member	–	–	Member	–
Vincent F. D'Annunzio	–	Member	Member	Chair	–
David C. Parke	Member	Chair	–	Member	Chair
Anthony J. Crisafio	Member	Member	–	–	–
Steven R. Williams	–	–	Chair	–	–
Thomas E. Riley	–	–	Member	–	Member

The Audit Committee of the Board is comprised entirely of persons whom the Board has determined to be independent under NASDAQ Rule 4200(a)(15). Mr. Swoveland chairs the committee; other audit committee members are Ms. Wakim, Mr. Parke and Mr. Crisafio. The Board has determined that Mr. Swoveland and the other Audit Committee members, with the exception of Mr. Parke, qualify as audit committee financial experts as defined by SEC regulations and are all, without exception, independent of management. The audit committee's purpose is to assist the Board in monitoring the integrity of the financial reporting process, systems of internal controls and financial statements of the Company, and compliance by the Company with legal and regulatory requirements. Additionally, the committee is directly responsible for the appointment, compensation and oversight of the independent auditors employed by the Company for the purpose of preparing or issuing an audit report or related work and to assess the need for an internal audit function and recommend its establishment when deemed appropriate.

The independent directors conduct meetings ("executive sessions") without the presence of management at each scheduled Board meeting. Mr. Swoveland serves as Presiding Independent Director of the Board.

Communications with Directors

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

Code of Ethics

In January 2003, the Company adopted its Code of Business Conduct and Ethics, as amended (the "Code of Conduct") applicable to all directors, officers, employees, agents and representatives of the Company and consultants. The Company's principal executive officer, principal financial officer and principal accounting officer are subject to additional specific provisions under the Code of Conduct. The Company's Code of Conduct is posted on its website at www.petd.com. In the event of an amendment to, or a waiver of, including an implicit waiver, the Code of Conduct, the Company will disclose the information on its internet website.

Section 16(a) Beneficial Ownership Reporting Compliance

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

Based solely on its review of the copies of such forms received by it, the Company believes that since January 1, 2006, all Section 16(a) filing requirements applicable to its directors, officers and greater than 10% beneficial owners were met.

ITEM 11. EXECUTIVE COMPENSATION

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The Compensation Committee of the Board of Directors ("Board") of Petroleum Development Corporation (the "Committee"), which consists of three independent Board members, developed and recommended for Board approval the compensation program for 2006 for the Chief Executive Officer ("CEO") and the other executive officers listed in the "2006 Summary Compensation Table" (collectively, the "named executive officers" or "executive officers") appearing below. The Committee's recommendations of compensation for the executive officers were approved by the Board. For 2007 executive compensation, the Board authorized the Committee to make final determinations for all elements of compensation for the executive officers, which the Committee did after reviewing its proposals with all other independent board members who are not part of the Committee. The Committee also negotiates terms of employment agreements with the executive officers. Prior to determining executive compensation, the Compensation Committee consults with the CEO for his evaluation of performance and recommendation for compensation of the other executive officers.

The Compensation Committee utilized the compensation consulting service of Towers Perrin ("Consultant") in recent years. Over the past 18 months, the Consultant: conducted a competitive benchmarking of the Company's executive and non-employee director compensation programs, helped the Committee in its redesign of the Long-Term Incentive ("LTI") program in 2007 as described below, and led an educational session focused on new SEC pay disclosure rules. The Consultant also assisted the Company with the design of a retention-based stock plan for non-officers. The Committee periodically assesses the effectiveness and competitiveness of the Company's executive compensation structure with the assistance of the Consultant, and utilizes the assistance of the Consultant in assessing the value and cost of various proposed compensation arrangements. The Consultant is engaged by, and reports directly to, the Committee.

Compensation Philosophy

The Committee considers many factors in establishing the compensation packages for the executive officers of the Company. The ultimate goal is to provide compensation that is fair to both the Company and the executive officers, that motivates behavior that will enhance the value of the Company, that avoids encouraging behavior that does not serve the best interests of the Company and that will allow the Company to attract and retain executive officers.

Objectives of Compensation Program

The Committee's philosophy is to provide compensation packages that will attract, motivate and retain executive talent and deliver rewards for superior performance and consequences for underperformance. Specifically, the objectives of the Committee's executive compensation practices are to:

- Offer a total compensation program that is competitive with the compensation practices of those peer companies with which the Company competes for talent;

- Tie a significant portion of executive compensation to the Company's achievement of pre-established financial and operating objectives and to personal objectives established for each executive individually;

- Provide a significant portion of overall compensation in the form of equity-based compensation in order to align the interests of the Company's executives with those of the Company's shareholders; and

- Structure a significant proportion of total compensation in a fashion that promotes executive retention.

The Committee seeks to attract executive talent by offering competitive base salaries, annual performance incentive opportunities under the Company's Short-Term Incentive ("STI") program and the potential for long-term rewards under the Company's equity-based LTI program. The Committee believes that to attract and retain a highly-skilled executive team, the Company's compensation practices must be competitive with those of other employers with which the Company competes for talent.

Pay-for-Performance

The Committee believes that significant portions of executive compensation should be closely linked to both the Company's and the individual's performance. The Committee's pay-for-performance philosophy is reflected in the Company's compensation practices, which tie a significant portion of executive compensation to the achievement of financial and operating objectives of the Company and also to take into account personal objectives and performance. The Committee believes that using solely financial objectives could unduly reward or punish executives for financial performance resulting from issues beyond the executive's control, such as changes in energy prices. On the other hand using solely operating measures could result in compensation practices that did not align the executive's interests with those of the shareholders. As a result, the Committee has chosen to use a combination of financial and operating measures as determinants for STI compensation. This philosophy is reflected in annual incentive awards, which are directly linked to the achievement of short-term financial and operating objectives, set by the Committee and have potential payouts ranging from zero to 200% of target for each of the three components. During 2006, the targets were increases in diluted earnings per share, increases in production, and the Committee's assessment of other factors related to the individual's performance and development. The following table summarized the criteria used in determining the bonus amount.

Criteria	Lower Threshold Amount	Target Bonus	Maximum Bonus	Percent of Total Maximum Bonus
Production increase based on Mcfe	6%	10%	14%	40%
Diluted earnings per share	$2.42	$2.66	$3.03	30%
Discretionary evaluation	Compensation Committee Determination			30%

The Committee also ties compensation to performance through equity-based LTI awards that are designed to motivate executives to meet the Company's long-term performance goals and to tie their interests to those of the shareholders. In 2006, the LTI awards consisted of restricted stock and stock options that vest 25% per year over a period of four years. For 2007, all of the LTI awards are restricted stock, a portion of which vest over time. The balance of the restricted stock awards will be long-term incentive performance shares ("LTIP shares"). The LTIP shares will vest only if certain minimum thresholds of stock price appreciation are met. One-half of the LTIP shares will vest and be issued based upon an annual stock price increase of approximately 12%. An additional 25% of the awarded LTIP shares will vest and be issued at annualized increased hurdles of 16% and an additional 25% at 20%. The stock price will be measured based on the average daily closing price for each of the three monthly periods: December 2009, 2010 and 2011. Any shares not vested in 2009 or 2010 will remain eligible to be vested in future years; however, any unvested shares at December 31, 2011 will be forfeited. The Committee decided to use three measurement dates to take into account the volatility of energy prices and their impact on the stock price of the Company.

As a result of the structure of the STI and LTI compensation, a significant amount of variable compensation under the Company's compensation program is contingent on the achievement of key financial and operating objectives of the Company and on increasing the value of the shares of the Company's stock.

For 2006, 30% of the Company's STI compensation program also accounts for individual performance through individual objectives and evaluation of individual executive performance by the Committee, which enables the Committee to differentiate among executives and emphasize the link between personal performance and compensation. For 2007, 100% of Mr. Stump's STI is discretionary and for the other executive officers, their STI performance based award percentages remain unchanged from 2006.

The Role of Equity-Based Compensation

The Company's LTI program is an integral part of the Company's overall executive compensation program. The LTI program is intended to serve a number of objectives. These include aligning the interests of executives with those of the Company's shareholders, and focusing senior executives on the achievement of well-defined, long-term performance objectives that are aligned with the Company's corporate strategy, thereby establishing a direct relationship between compensation and shareholder value. The program also furthers the goal of executive retention, since the executive officer will forfeit any unvested awards in the event the officer voluntarily terminates employment with the Company without "good reason."

In making long-term incentive awards, the Committee uses a pre-determined market-based value approach. The Committee determines the dollar value of awards in the marketplace using a valuation methodology. The Committee establishes the desired dollar value for each executive officer relative to the market. The corresponding number of equity instruments to be awarded is then determined using the same valuation methodology, based on prevailing factors in advance of the award date. The valuation for financial statement purposes is subsequently re-calculated based on the prevailing factors at the time of the award.

The value-based approach can cause the number of equity instruments needed to be granted from year to year to vary, even though the awards may have the same dollar value. This can be caused by, among other things, fluctuations in the Company's common stock price at the time of grant. This issue is further addressed in the Long-Term Incentives section.

Use of Benchmarking to Establish Target Compensation Levels

In furtherance of its compensation objectives, the Committee compared the Company's compensation levels with those of a group of 14 companies in 2006, and 15 companies in 2007, in setting compensation targets. These groups, collectively, are referred to as the "Peer Group." This benchmarking is done with respect to each of the key elements of the Company's executive compensation programs discussed above (salary, STI and LTI compensation), as well as the compensation of individual executives based on their position in the overall compensation hierarchy. The Committee uses data from the Peer Group to establish a dollar target level for each key element to deliver compensation to each executive at approximately the 50th percentile of the Peer Group, with adjustments made based on the executive's individual performance. Targeting the 50th percentile helps ensure that the Company's compensation practices will be competitive in terms of attracting and retaining executive talent, while performance based compensation provides for variations due to superior or sub-par performance. Because compensation for the Peer Group is for prior periods, the Committee attempts to anticipate future movements in compensation levels when it sets compensation targets. For example, when setting compensation for 2006, the most recent compensation information available was from the 2005 proxy statements for compensation paid in 2004. As more up to date information becomes available, it is reviewed by the Committee to evaluate whether future compensation plans should be adjusted to take unanticipated changes in actual compensation of the Peer Group into account.

The 2006 Peer Group was comprised of the following companies:

- Unit Corporation
- Penn Virginia Corporation
- Encore Acquisition Company
- Quicksilver Resources Inc
- Magnum Hunter Resources Incorporated
- St. Mary Land & Exploration Company
- Whiting Petroleum Corporation
- Berry Petroleum Company
- Clayton Williams Energy Incorporated
- Cimarex Energy Company
- Cabot Oil & Gas Corporation
- Range Resources Corporation
- KCS Energy Incorporated
- Brigham Exploration Company

For 2007, Forest Oil Corporation, Comstock Resources Incorporated and Bill Barrett Corporation were added to the Peer Group. Cimarex acquired Magnum Hunter in 2005 and these companies were removed from the Peer Group as they were no longer comparable due to size. The Committee believes that the Peer Group represents companies with similar operations, of similar complexity, and with which the Company believes it competes for executive talent.

Review of Overall Compensation

The Committee reviews for each of the executive officers the total dollar value of the officer's annual compensation, including salary, STI, LTI compensation, perquisites, deferred compensation accruals and other compensation. The Committee also reviews shareholdings and accumulated unrealized gains under prior equity-based compensation awards, and amounts payable to the executive officer upon termination of the executive's employment under various different circumstances, including retirement and termination in connection with a change in control. See 2006 Summary Compensation Table below.

Consideration of Prior Compensation

While the Committee considers all compensation previously paid to the executive officers, including amounts realized or realizable under prior equity-based compensation awards, the Committee believes that current compensation practices must be competitive to retain the executives in light of prevailing market practices and to motivate the future performance of the executive officers. Accordingly, wealth accumulation through superior past performance of the Company should not be punished through reductions in current compensation levels.

Elements of Executive Compensation

To accomplish the objectives of the executive compensation program, the Committee uses four elements of compensation in varying proportions for the different executive officers. These elements are base salary, STI, LTI, and other benefits. The Committee uses cash payments (base salary and STI), awards tied to the Company's stock (LTI, which we also refer to as "equity-based compensation") and non-cash benefits in its overall compensation packages. The Committee balances salary and performance-based compensation, and cash and non-cash compensation, in a manner it believes best serves the objectives of the Company's compensation program. The Committee allocates among the different elements of compensation in a manner similar to the median allocation of the Peer Group, based on the level of the executive's position. Generally, it is the policy of the Committee that, as income levels increase, a greater proportion of the executive's income should be in the form of STI and LTI compensation. For example the CEO of the Company receives a higher percentage of his compensation in the form of short and long term incentives compared to other executives, as is the case of CEOs in the Peer Group. The following table shows the breakdown of target compensation among the three elements for 2006 and 2007 for each executive officer.

Target Compensation for Elements as a Percentage of Total Target Compensation						
	2006			2007		
Name	Base Salary	Bonus Target	Equity Target	Base Salary	Bonus Target	Equity Target
Steven R. Williams	31%	23%	46%	33%	24%	43%
Thomas E. Riley	36%	18%	46%	36%	22%	42%
Eric R. Stearns	37%	19%	44%	36%	23%	41%
Richard W. McCullough[1]	–	–	–	40%	20%	40%
Darwin L. Stump	39%	19%	42%	44%	22%	34%

(1) *Mr. McCullough was appointed as CFO in November 2006. The initial contract period runs through 2008.*

Base Salary

The Committee annually reviews the base salaries of the Chief Executive Officer ("CEO") and other executive officers. Salaries are also reviewed in the case of promotions or other significant changes in responsibilities. In each case, the Committee takes into account the results achieved by the executive, his or her future potential, scope of responsibilities and experience, and competitive salary practices of the Peer Group. Base salary is intended to provide a baseline of compensation that is not contingent upon the Company's performance.

After reviewing the Peer Group salary levels and considering individual performance, the Committee established Base Salary increases for 2006 of 8.5% for the CEO, and between 5% and 8.7% for the other executive officers. The total compensation of the executive officers approximated the mean of the Peer Group, although the spread between the highest and lowest is less than the Peer Group. This is consistent throughout the elements of compensation, and reflects the goal of the Committee to encourage a strong team among the executive officers. For 2007, the Committee established Base Salary increases of 7.2% for the CEO, and between 0% and 8.2% for the other executive officers. Mr. McCullough, the Company's CFO, will receive the compensation established in his employment contract, executed in November 2006. Annual base salaries for the executive officers for 2006 and 2007 are shown in the following table:

Annual Base Salaries		
Name	2006	2007
Steven R. Williams	$ 345,000	$ 370,000
Thomas E. Riley	272,000	292,500
Eric R. Stearns	251,000	271,500
Richard W. McCullough	–	235,000
Darwin L. Stump	220,500	220,500

Short-Term Incentives

Annual STI are tied to the Company's overall performance for the fiscal year, as measured against objective criteria set by the Committee, as well as the Committee's assessment of individual performance of each executive. For 2006, at least 70% of the target STI payments are performance based awards measured against objective criteria established early in the fiscal year. The remainder may include additional awards based on performance goals, or may be awarded at the discretion of the Committee based on its assessment of the executive's performance. For 2007, 100% of Mr. Stump's STI is discretionary and for the other executive officers, their STI performance based award percentages remain unchanged from 2006. The Compensation Committee has decided to maintain discretion over STI bonus amounts for Mr. Stump to emphasize the focus of his role in 2007 on the continued development of the accounting functions of the Company rather than on production targets and overall financial performance. The Committee, comprised entirely of independent directors, believes that some discretion with respect to individual awards is desirable to compensate for unusual and unexpected events.

Target STI payments, expressed as a percentage of base salary, are set for each executive officer prior to the beginning of the fiscal year based on job responsibilities. STI payments for the year may range from zero up to 150% of the executive officer's base salary, based on the achievement of the objective criteria for performance based payments and the assessment by the Committee for individual goals. For fiscal year 2006 and again in 2007, target STI awards for the executive officers ranged from 50% to 75% of salary.

With respect to the executive officers, the Committee establishes formulae to determine the percentage of the target annual incentive payment that may be payable for the fiscal year. The Committee does not have the discretion to change any objective criteria once they have been established. However, the Committee does retain discretion over 30% (in 2007, 100% for Mr. Stump) of the total target STI to allow some flexibility to award superior, or reflect the effect of sub-par, personal performance that may not be captured by the financial and operating criteria. In addition, the Committee has the authority to recommend to the Board compensation for unusual events. In 2006, Eric Stearns, the Executive Vice President of Exploration and Production, received a special bonus for his key role in the $354 million acreage sale to Marathon. The following table sets forth the STI threshold, target and maximum levels for 2006 and 2007 for the executives expressed as a percentage of base salary.

	Short-Term Incentive Compensation					
	2006			2007[(1)]		
	% of Base Salary			% of Base Salary		
Name	Threshold	Target	Stretch	Threshold	Target	Stretch
Steven R. Williams	0%	75%	150%	0%	75%	150%
Thomas E. Riley	0%	50%	100%	0%	62.5%	125%
Eric R. Stearns	0%	50%	100%	0%	62.5%	125%
Richard W. McCullough[(2)]	–	–	–	0%	50%	100%
Darwin L. Stump	0%	50%	100%	–	–	–

(1) *In 2007, the target percentages apply to Messrs. Williams, Riley, Stearns and McCullough. For Mr. Stump, 100% of his STI is discretionary.*
(2) *Mr. McCullough was appointed as CFO in November 2006. The initial contract period runs through 2008.*

Long-Term Incentives

Historically, the primary form of equity compensation awarded by the Company was qualified and non-qualified stock options. This form was selected because of the favorable individual and corporate accounting and tax treatments provided by the accounting and tax rules prevalent at the time, and the widespread use of stock options in executive compensation. In 2004, the Committee began utilizing a combination of restricted stock and options for executive compensation, believing that the restricted stock was better appreciated by employees and resulted in less dilution for the Shareholders. Beginning in 2006, the accounting treatment for stock options changed as a result of the applicability of Statement of Financial Accounting Standards No. 123(R), making the use of stock options less attractive. As a result, the Committee assessed the desirability of granting only shares of restricted stock to executives, and concluded that shifting entirely to restricted stock would provide an equally motivating form of incentive compensation, while permitting the issuance of fewer shares, thereby reducing potential dilution to other shareholders. The Committee did want to tie the value received by executives to performance for a portion of the equity compensation, thereby providing executives with a greater incentive to focus on the long-term appreciation of the stock. To accomplish this, a portion of the LTI for each executive consists of LTI performance shares ("LTIP shares"), which require both the passage of time and specified increases in the stock price to become vested.

The Committee's practice has been to determine the dollar amount of equity compensation and to then grant a number of shares of restricted stock and options that have a fair value equal to that amount on the date of grant. The 2007 awards were determined using the fair value of the awards based on the average daily closing price of the Company's stock in December 2006. The Consultant calculated the fair value utilizing methods they have developed for use with these types of equity valuations, including taking into account the probability and/or timing of vesting under the performance criteria for the LTIP shares and the other restricted stock. For the purpose of recording an expense for financial reporting purposes, the awards will be revalued based on the prevailing capital markets factors at the time of the award.

In April 2007, the Company corrected an administrative error in the stock option exercise price of shares awarded the executive officers in March 2006, none of which were exercised. The administrative error related to the use of the closing price of the Company's common stock on the day prior to the award, rather than the closing price on the day of the award in accordance with the Company's 2004 Long-Term Equity Compensation Plan. The need for the correction was identified by the Company and the effect of the correction was not material to the fair value of the awards, either at the time of the award or the time of the correction.

For 2006, the fair value of all Long-Term Incentive ("LTI") awards was divided as follows: 70% for time vesting restricted stock and 30% for stock options (with both types of awards vesting 25% per year over a four year period). In 2007, a percentage of the equity-based compensation awards are LTIP shares with the percentage increasing for more highly compensated executives, and the balance of the awards are time vesting restricted stock. For example, 50% of the CEO's equity-based compensation in 2007 will be LTIP shares, in contrast to 40% for the President and 30% for the CAO. The following table summarizes LTI awards for 2006 and 2007, and the second table summarizes the target prices for the performance vesting of the LTIP awards.

	Long-Term Incentive Compensation					
	2006			2007		
Name	Percent of Salary	Percent of Value from Time Vesting Restricted Stock	Percent of Value from Stock Options	Percent of Salary	Percent of Value from Time Vesting Restricted Stock	Percent of Value from LTIP Stock
Steven R. Williams	150%	70%	30%	175%	50%	50%
Thomas E. Riley	125%	70%	30%	145%	60%	40%
Eric R. Stearns	120%	70%	30%	140%	60%	40%
Richard W. McCullough[(1)]	100%	70%	30%	–	–	–
Darwin L. Stump	110%	70%	30%	90%	70%	30%

[(1)] *LTI awarded in 2006 pursuant to initial employment agreement. Mr. McCullough will be eligible for annual award consideration beginning in 2008.*

LTIP Target Prices [(1)]				
Approximate	Target Price			Percent Vested if
Growth Target	Year 3	Year 4	Year 5	Target Attained[(2)]
12%	$ 60.00	$ 67.50	$ 75.00	50%
16%	67.50	77.50	90.00	75%
20%	75.00	90.00	107.50	100%

[(1)] *Growth target percentages and target prices are based on the average closing price of the Company's common stock during the preceding December for each of the years ended December 31, 2009, 2010 and 2011.*

[(2)] *Performance shares will vest for a performance period only if the target price is met or exceeded for such period. Performance shares vested for a performance period shall not be subject to divestment in the event the share price subsequently decreases below the threshold in a subsequent performance period.*

Retirement Plans

As of January 1, 2006, the Company maintained a 401(k) plan and a qualified profit sharing plan for all of the Company's employees including the executive officers. On July 1, 2006, the two plans were combined into a single plan. The plan provides for discretionary matching contributions. Generally, the Company matches employee 401(k) contributions dollar for dollar up to 10% of the employee's compensation and then matches 20% for contributions above 10% of the employees' compensation up to the maximum allowable limits under the Internal Revenue Code ("IRC"). The Company's profit sharing contribution is discretionary and for 2006 was equal to 1% of the Company's consolidated net income. Total Company contributions, to both 401(k) and profit sharing, to the plan in 2006 were $3.1 million.

Under their current employment agreements, each of the executive officers also earns the right to future payments following their retirement or other departure from the Company. For each year worked under his current agreement, the CEO earns an annual retirement benefit equal to $500 times the number of his full years of service times 10 ($500 per year of service for 10 years). Following the termination of his service with the Company, the cumulative total of the calculated annual retirement benefits is disbursed in ten equal annual installments. For 2006, the retirement benefit was $115,000 ($11,500 per year for 10 years) and for 2007, the retirement benefit will be $120,000 ($12,000 per year for 10 years). The CEO's total cumulative retirement benefit, under this plan, at December 31, 2006, was $330,000 ($33,000 per year for 10 years). Each of the other executive officers, under their respective employment agreements, annually earns a retirement benefit equal to $75,000 ($7,500 per year for 10 years). Following their termination of service with the Company, their cumulative total annual retirement benefit will be disbursed in ten equal annual installments. As of December 31, 2006, for each of the other executive officers, excluding Mr. McCullough, the total cumulative benefit, including the 2006 increment, was $225,000 ($22,500 per year for 10 years). As of December 31, 2006, Mr. McCullough had not yet completed sufficient service to qualify for the benefit, but will, like the others, be eligible in 2007.

Additionally, under his previous employment agreement, Mr. Williams earned supplemental retirement benefits. The prior agreement requires the Company to pay Mr. Williams an annual sum of $40,000 per year for the ten year period following his retirement from the Company (an aggregate of $400,000). This benefit was fully vested on December 31, 2003. Under provisions of his previous employment agreement, Mr. Williams may elect to defer payment up to five years following his retirement. In the event of employment beyond the five year vesting period or the deferral of payment following retirement the amount of the annual benefit will be increased by 10.75% compounded annually. As of December 31, 2006, the amount of this benefit is $543,470 (or $54,347 per year for 10 years). In the event of change in control the benefits due under this agreement will be accelerated and due immediately.

Other Compensation and Benefits

The Company also provides certain other benefits to its executive officers that are not tied to any formal individual or Company performance criteria and are intended to be part of a competitive overall compensation program. Each of the executive officers has 1) a Company vehicle (or vehicle allowance) that they use for Company business, and are allowed to use for personal uses as well, 2) coverage under the Company's medical plan and reimbursement of medical expenses not covered by the plan, 3) the right to be reimbursed for one Board-approved club membership, 4) reimbursement of the cost of a $1 million life insurance policy, and 5) reimbursement of the cost of disability insurance. Given the importance of the executives and their good health to the success of the Company and the achievement of its business goals, the Committee believes that the medical insurance and reimbursement encourage the executives to seek appropriate medical assistance. The other benefits are commonly provided to executives and are necessary to create a competitive compensation package.

Termination Benefits including Change in Control Payments

The Committee believes that severance benefits for senior management should reflect the fact that it may be difficult for employees to find comparable employment within a short period of time. They also should disentangle the Company from the former employee as soon as practicable. For instance, while it is possible to provide salary continuation to an employee during the job search process, which in some cases may be less expensive than a lump-sum severance payment, a lump-sum severance payment is preferable in order to most cleanly sever the relationship as soon as practicable. The Company has entered into employment agreements with each of the executive officers that include change in control provisions. These agreements provide for the continued employment of the executives for a period of two years following a change in control of the Company. These agreements are intended to retain the executives and provide continuity of management in the event of an actual or threatened change in the control of the Company and ensure that the executive's compensation and benefits expectations would be satisfied in such event.

The compensation provisions in the event of a change in control also serve to lessen the potential negative impact of a change in control on the executive officers. The Committee believes this is desirable to encourage the executives to consider possible change in control situations that might benefit the Company's shareholders.

Where the termination is without "cause" or the executive officer terminates employment for "good reason," the severance plan provides for benefits equal to three times the sum of: a) the executive officer's highest base salary during the previous two years of employment immediately preceding the termination date, plus b) the highest bonus paid to the executive officer during the same two year period. The executive officer is also entitled to 1) vesting of any unvested equity compensation, 2) reimbursement for any unpaid expenses, 3) retirement benefits earned under the current or previous agreements, 4) continued coverage under the Company's medical plan for up to 18 months, and 5) payment of any earned, unpaid bonus amounts. In addition, a terminated executive officer is entitled to receive any benefits that he otherwise would have been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated. The Committee believes that these termination benefits are comparable to the general practice among similar companies, although it has not conducted a study to confirm this.

Good reason includes 1) assignment to the executive of duties materially and adversely inconsistent with his position, duties, responsibilities and status with the Company, 2) an adverse change in the executive's position with the Company, 3) a change in control of the Company, 4) a decrease of the executive officer's base salary, 5) a material reduction in the benefits provided by the Company, 6) the requirement by the Company for the executive officer to be based anywhere outside of Bridgeport, West Virginia, 7) the failure by the Company to obtain a satisfactory agreement from any successor or assignee of the Company to assume and agree to the Company's obligations under the employment agreement, or 8) any other material breach of the employment agreement by the Company.

The Company may terminate any of the executive officers for just cause, which is defined in the employment agreements to include 1) a failure by the executive to perform his duties, 2) conduct by the executive that results in consequences which are materially adverse to the Company, monetarily or otherwise, 3) a guilty plea or conviction of a felony, or 4) a material breach of the terms of the employment agreement by the executive officer. If an executive officer is terminated for just cause, the Company is required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

If an executive officer voluntarily terminates his employment with the Company for other than good reason, he is entitled to receive 1) the base salary, bonus and incremental retirement payment prorated for the portion of the year that the executive officer is employed by the Company, 2) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted or in full without discount within 60 days of the termination date at the discretion of the Company, 3) any unpaid expense reimbursement upon presentation by the executive officer of an accounting of such expenses in accordance with normal Company practices, and 4) any other payments for benefits earned under the employment agreement or Company plans.

The table below provides information regarding the amounts each of the executive officers would be eligible to receive if a termination event had occurred as of December 31, 2006:

	Termination Benefits			
Name	Retirement or Voluntary Termination by Executive	Termination For Cause by Company	Change in Control or Termination Without Cause or Good Reason by Executive	Death/ Disability[(1)]
Steven R. Williams[(2)]	$ 1,669,067	$ 1,513,817	$ 4,198,813	$ 2,286,078
Thomas E. Riley	541,252	459,652	2,172,522	1,069,117
Eric R. Stearns	520,252	444,952	2,315,782	1,000,160
Richard W. McCullough[(3)]	-	-	1,153,767	317,267
Darwin L. Stump	456,677	423,602	1,839,846	681,171

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(1) *In the event of death or disability, the termination benefits would consist of (i) the base salary and bonus for the portion of the year the executive officer is employed by the Company; (ii) the base salary that would have been earned for six months after termination; (iii) immediate vesting of all equity and option awards; (iv) the payment of deferred retirement compensation based upon the schedule originally contemplated in the deferred retirement compensation agreement or in a lump-sum no later than two and one-half months following the close of the calendar year in which the death or disability occurred; (v) reimbursement for any unpaid expenses; (vi) any benefits earned under the 401(k) and profit sharing plan; and (vii) continued coverage under the Company's medical plan, life time coverage for Mr. Williams and for up to 18 months for all other named executive officers.*

(2) *Includes (i) the estimated lifetime value of medical benefits for Mr. Williams and/or his spouse; and (ii) the sum of deferred retirement compensation benefits related to prior employment agreement and current employment agreement.*

(3) *Includes a signing bonus of $83,000 (employment effective November 15, 2006). If employment terminates within one year after commencement of employment, Mr. McCullough must refund to the Company a pro-rata portion of the signing bonus.*

Executive and Director Share Retention and Ownership Guidelines

In order to promote equity ownership and further align the interests of management with the Company's shareholders, the Committee has adopted share retention and ownership guidelines for senior management and non-employee directors. Under these guidelines, executive officers and non-employee directors are required to achieve and continue to maintain a significant ownership position, expressed as a multiple of salary as follows:

Chief Executive Officer	3 times salary
Other Executive Officers (4 persons)	2 times salary
Non-Employee Directors	1 times retainer

The Committee periodically reviews share ownership levels of the persons subject to these guidelines. Shares held by the executive officers and shares held indirectly through the Company 401(k) plan are included in determining an executive officer's share ownership. Shares underlying stock options, including vested options, as well as unvested restricted stock, are not included. Each of the executive officers, excluding Mr. McCullough who was hired in November 2006, and the non-employee directors have achieved shareholdings in excess of the applicable multiple set forth above.

The Company's insider trading policy expressly prohibits Company officers, directors, employees and associates from engaging in options, puts, calls or other transactions that are intended to hedge against the economic risk of owning the Company shares.

Employment Agreements

The Company entered into employment agreements with Messrs. Williams, Riley, Stearns and Stump effective January 1, 2004, and Mr. McCullough effective November 13, 2006. The initial term of the agreements is for two years and they are automatically extended for an additional 12 months beginning on the first anniversary of the effective date and on each successive anniversary unless either party cancels. The employment agreements provide for the base annual salary to be reviewed annually (see "Base Salary" discussion above).

Each employment agreement provides for an annual performance bonus as determined by the Compensation Committee and is based in part upon written objective criteria and in part upon the discretion of the Compensation Committee. The annual performance bonus earned is calculated as a percentage, as determined by the Compensation Committee, of the executive officers' base salary.

Each employment agreement contains a standard non-disclosure covenant and, also, provides that the executive officer is prohibited during the term of his employment and for a period of one year following his termination from engaging in any business that is competitive with the Company's oil and gas drilling business. Additionally, the employment agreements state that the executive officer must devote substantially all of his business time, best efforts and attention to promote and advance the business of the Company. The executive officer may not be employed in any other business activity, other than with the Company, during the term of the employment agreement, whether or not such activity is pursued for gain, profit or other pecuniary advantage without approval by the Compensation Committee of the Board. This restriction will not prevent the executive officer from investing his personal assets in a business which does not compete with the Company or its affiliates, and where such investment will not require services of any significance on the part of the executive officer in the operation of the affairs of the business.

Other Agreements and Arrangements

Executive officers may invest in a Board-approved executive drilling program at the Company's cost. During 2006, Messrs. Williams, Riley and Stump invested approximately $40,000, $20,000 and $17,000, respectively. Other investors participating in drilling with the Company are generally charged a profit or markup above the cost of the wells; for example, the markup on Company-sponsored partnerships is approximately 15% of the cost of the wells. As a result, the executive officers realize a benefit not generally available to other investors. The Board believes that having the executive officers invest in wells with the Company and other investors helps to create a commonality of interests much like share ownership creates a commonality of interests between the shareholders and executive officers.

Internal Revenue Code Section 162(m)

The Committee is aware of IRC Section 162(m) of the tax code, which generally limits the deductibility of executive pay in excess of one million dollars, and which specifies the requirements for the “performance-based” exemption from this limit. Elements of the executive compensation program are indeed performance-based, and vehicles such as stock options are believed to qualify as performance-based under Section 162(m). Other aspects of the executive compensation program may not qualify as performance-based, such as time-based restricted stock and our annual incentive plan because the Committee prefers the ability to exercise discretion in evaluating a portion of participants' performance. The financial implications of a potential lost deduction are not expected to be material. The Committee will continue to monitor its position on the impact of Section 162(m) for the Company's executive compensation programs.

Compensation Committee Report

The Compensation Committee has met to review and discuss with the Company’s management the specific disclosure contained under the heading “Compensation Discussion and Analysis”. Based on its review and discussions with management the Compensation Committee has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

This report has been provided by the Compensation Committee of the Board of Directors of the Company.

David C. Parke, Chairman
Vincent F. D'Annunzio
Anthony J. Crisafio

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2006 SUMMARY COMPENSATION TABLE

The following table provides summary compensation information for the Company's Chief Executive Officer, the Chief Financial Officer, and the three most highly compensated executive officers, other than the Chief Executive Officer and Chief Financial Officer, whose total compensation exceeded $100,000 in 2006 (the "named executive officers").

Name and Principal Position	Salary	Bonus[1]	Stock Awards [2]	Option Awards [3]	Non-Equity Incentive Plan Compensation[4]	Nonqualified Deferred Compensation [5]	All Other Compensation [6]	Total Compensation
Steven R. Williams Chairman, Chief Executive Officer and Director	$ 345,000	$ 155,250	$ 163,023	$ 54,546	$ 362,250	$ 88,438	$ 37,778 [7]	$ 1,206,285
Thomas E. Riley President and Director	272,000	81,600	107,580	35,977	190,400	30,824	9,357 [8]	727,738
Eric R. Stearns Executive Vice President, Exploration and Development	251,000	175,300 [9]	98,318	32,806	175,700	21,730	17,773	772,627
Richard W. McCullough Chief Financial Officer and Treasurer	32,237	83,000 [10]	5,928	2,289	-	3,848	-	127,302
Darwin L. Stump Chief Accounting Officer	220,500	33,075	85,963	28,484	154,350	25,880	17,610 [11]	565,862

(1) *The annual STI bonus plan provides for a discretionary component equal to 30% of the total STI award. The amounts for Messrs. Williams, Riley, and Stump represent only the discretionary amounts earned pursuant to the STI plan. The annual STI bonus plan has established performance criteria that must be met before 70% of the annual cash bonus may be paid. See discussion of the STI bonus plan above.*

(2) *Represents compensation expense recorded by the Company pursuant to FAS 123(R) related to outstanding restricted stock awards. See Note 8, Common Stock, to the Consolidated Financial Statements.*

(3) *Represents compensation expense recorded by the Company pursuant to FAS 123(R) related to outstanding stock options. See Note 8, Common Stock, to the Consolidated Financial Statements.*

(4) *Represents performance based cash bonuses earned during the year and paid shortly after year-end. As noted above in the discussion and analysis, the STI bonus plan has established performance criteria that must be met for the executive to earn 70% of the targeted annual cash bonus amount.*

(5) *Represents the present value of the current year benefit earned related to the deferred compensation retirement plan. The amount for Mr. McCullough was based upon a prorated annual amount since 2006 was the initial year of employment.*

(6) *All Other Compensation includes insurance and medical reimbursements, social fringe benefits such as club dues and athletic event tickets, the value for the personal use of Company automobiles and discounts related to Company-sponsored drilling programs.*

(7) *Includes, in addition to other compensation items discussed in (6) above, $20,170 for post retirement medical and a discount received of $5,216 related to investments in Company-sponsored drilling programs, see discussion above in Other Agreements and Arrangements.*

(8) *Includes, in addition to other compensation items discussed in (6) above, a discount received of $2,649 related to investments in Company-sponsored drilling programs.*

(9) *Includes $75,300 pursuant to discretionary component of the STI plan and an additional $100,000 bonus for his role in the sale of an undeveloped leasehold in Grand Valley Field in September.*

(10) *Represents a signing bonus paid at the start of employment with the Company in November 2006.*

(11) *Includes, in addition to other compensation items discussed in (6) above, a discount received of $2,437 related to an investment in a Company-sponsored drilling program.*

2006 GRANTS OF PLAN-BASED AWARDS TABLE

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Number of Shares Awarded	Number of Securities Underlying Option Awards[(1)]	Exercise Price Per Share of Option Awards[(1)]	Grant Date Fair Value of Stock and Option Awards [(2)]
		Threshold	Target	Maximum				
Steven R. Williams	3/16/2006	$ -	$ -	$ -	9,348	7,517	$ 44.95 [(3)]	$ 571,886
	6/23/2006	-	258,750	517,500	-	-	-	-
Thomas E. Riley	3/16/2006	-	-	-	6,141	4,939	44.95 [(3)]	375,707
	6/23/2006	-	136,000	272,000	-	-	-	-
Eric R. Stearns	3/16/2006	-	-	-	5,441	4,375	44.95 [(3)]	332,860
	6/23/2006	-	125,500	251,000	-	-	-	-
Richard W. McCullough	11/14/2006	-	-	-	4,256	3,333	43.60	255,688
Darwin L. Stump	3/16/2006	-	-	-	4,381	3,523	44.95 [(3)]	268,020
	6/23/2006	-	110,250	220,500	-	-	-	-

(1) *Represents awards under the Company's long-term equity compensation plan (see Note 8, "Common Stock," to the consolidated financial statements and "Long-Term Incentives" above in the Compensation Discussion and Analysis for additional discussion).*

(2) *The Grant Date Fair Value of stock and option awards is computed by multiplying the restricted stock number of shares awarded by the closing price of the Company's stock on the date of the grant, plus the Black Scholes value per share times the number of securities underlying the option shares. The closing price per share of awards on March 16, 2006, and November 14, 2006, was $44.95 and $43.60, respectively. The Black Scholes estimated fair value per share of the options awarded on March 16, 2006, and November 14, 2006, was $20.18 and $21.04, respectively.*

(3) *In April 2007, the Company corrected an administrative error related to the use of the closing price of the Company's common stock on the day prior to the award, rather than the closing price on the day of the award in accordance to the plan, see Long-Term Incentives discussion above. The Exercise Price Per Share correctly reflects the closing price per share on the day of the award.*

Outstanding Equity Awards at 2006 Fiscal Year-End Table

	Option Awards				Restricted Stock Awards	
	Number of Securities Underlying Unexercised Options Held at December 31, 2006					
Name	Exercisable	Unexercisable	Exercise Price	Expiration Date	Number of Shares That Have Not Vested	Market Value of Shares That Have Not Vested [1]
Steven R. Williams	2,935	2,935 [2]	$ 37.15	12/13/2014	13,413 [3]	$ 577,430
	-	7,517 [4]	44.95	3/16/2016	-	-
Thomas E. Riley	1,945	1,945 [5]	37.15	12/13/2014	8,836 [6]	380,390
	-	4,939 [7]	44.95	3/16/2016	-	-
Eric R. Stearns	1,835	1,835 [8]	37.15	12/13/2014	7,981 [9]	343,582
	-	4,375 [10]	44.95	3/16/2016	-	-
Richard W. McCullough	-	3,333 [11]	43.60	11/14/2016	4,256 [12]	183,221
Darwin L. Stump	1,725	1,725 [13]	37.15	12/13/2014	6,771 [14]	291,492
	-	3,523 [15]	44.95	3/16/2016	-	-

(1) *Market value of shares is based on the closing price of the Company's common stock on December 29, 2006, $43.05 per share.*
(2) *Vesting: 1,467 shares in 2007 and 1,468 shares in 2008.*
(3) *Vesting: 4,369 shares in 2007, 4,370 shares in 2008, 2,337 shares in 2009 and 2,337 shares in 2010.*
(4) *Vesting: 25% in each of the years 2007 through 2010.*
(5) *Vesting: 972 shares in 2007 and 973 shares in 2008.*
(6) *Vesting: 2,882 shares in 2007, 2,883 shares in 2008, 1,535 shares in 2009 and 1,536 shares in 2010.*
(7) *Vesting: 25% in each of the years 2007 through 2010.*
(8) *Vesting: 917 shares in 2007 and 918 shares in 2008.*
(9) *Vesting: 2,630 shares in 2007, 2,630 shares in 2008, 1,360 shares in 2009 and 1,361 shares in 2010.*
(10) *Vesting: 25% in each of the years 2007 through 2010.*
(11) *Vesting: 25% in each of the years 2007 through 2010.*
(12) *Vesting: 25% in each of the years 2007 through 2010.*
(13) *Vesting: 862 shares in 2007 and 863 shares in 2008.*
(14) *Vesting: 2,290 shares in 2007, 2,290 shares in 2008, 1,095 shares in 2009 and 1,096 shares in 2010.*
(15) *Vesting: 25% in each of the years 2007 through 2010.*

2006 Options Exercises and Stock Vested Table

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting	Value Realized on Vesting[1]
Steven R. Williams	-	$ -	2,032	$ 90,932
Thomas E. Riley	-	-	1,347	60,278
Eric R. Stearns	-	-	1,270	56,833
Richard W. McCullough	-	-	-	-
Darwin L. Stump	-	-	1,195	53,476

(1) Based on the closing price of the Company's common stock on the date of vesting, December 13, 2006, $44.75 per share.

2006 Nonqualified Deferred Compensation Table

Name	Executive Contributions in 2006	Company Contributions in 2006[1]	Aggregate Earnings in 2006[2]	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2006
Steven R. Williams	$ -	$ 88,438 [3]	$ 35,699 [4]	$ -	$ 754,821
Thomas E. Riley	-	30,824	3,489	-	92,471
Eric R. Stearns	-	21,730	2,460	-	65,189
Richard W. McCullough	-	3,848	-	-	3,848
Darwin L. Stump	-	25,880	2,930	-	77,641

(1) Company contributions include the present value cost of providing the defined compensation payout over a ten year period. Since this is a self funded deferred compensation plan, the Company's additional annual deferred compensation expense, less the interest component noted as aggregate earnings above, equals the increase in the accrued Company contributions that are required to fund the plan. These annual amounts are a component of the executive officers' 2006 compensation and are included in the 2006 Summary Compensation Table.

(2) Aggregate earnings consist of interest income earned on the beginning of the year compensation balance at a 6% interest rate. These earnings are not included in the 2006 Summary Compensation Table as they are not above market rate.

(3) Mr. Williams received deferred compensation benefits from both the current deferred compensation plan for all named executive officers, as well as a prior retirement plan. The amount for Mr. Williams includes a reduction of $8,990 in the current funding amount due to the fact that the deferral option has been elected by Mr. Williams for the start of benefits under the prior retirement plan. The deferred payment start date has been deferred for five years after retirement. In addition, current year required Company contributions were also reduced by $35,699 due to a change in Mr. Williams' projected retirement date.

(4) Aggregate earnings for Mr. Williams include additional earnings of $4,590 on the Company's previous retirement plan due to that plan's "five year deferral option".

DIRECTOR COMPENSATION

Each non-employee director received an annual retainer of $40,000 during 2006. Additionally, non-employee directors receive a fee for being a member of certain committees. During the third quarter of 2006, the audit committee chairperson began receiving an annual fee of $13,000, payable quarterly, and the other audit committee members began receiving an annual fee of $8,000, each, also payable quarterly. The compensation committee chairperson received an annual fee of $2,500 and the nominating committee chairperson received an annual fee of $2,500. Non-employee directors also receive restricted stock compensation. Pursuant to the shareholder approved, Non-Employee Director Restricted Stock Plan (the "Restricted Stock Plan"), as of the date of each annual stockholders meeting of the Company each non-employee director will be awarded a specified number of shares of Restricted Stock as determined by the Board. The amount of the award for the upcoming plan year will be disclosed in the Company's proxy statement. Directors receiving Restricted Stock under the Restricted Stock Plan will have all of the rights of a stockholder including the right to vote the shares and receive cash dividends and other cash distributions. Restricted Stock will be subject to the restrictions of the Restricted Period commencing on the date the stock is awarded. Each non-employee director can choose to defer a portion or all of their annual cash compensation by participating in the Non-Employee Director Deferred Compensation Plan. The plan's trustee will invest all cash deposits received exclusively in the common stock of the Company.

2006 Director Compensation Table

Name	Fees Earned/ Paid in Cash	Stock Awards (1)	Option Awards	All Other Compensation	Total
Kimberly Luff Wakim	$ 46,500 (2)	$ 26,310	$ -	$ -	$ 72,810
Vincent F. D'Annunzio	42,500 (3)	41,464	-	-	83,964
David C. Parke	44,500	23,088	-	-	67,588
Jeffrey C. Swoveland	45,250	23,088	-	-	68,338
Donald B. Nestor	35,750 (4)	19,996	-	-	55,746
Anthony J. Crisafio	12,000	2,882	-	-	14,882

(1) *Represents compensation expense recorded by the Company pursuant to FAS 123(R). See Note 8, Common Stock, to the Consolidated Financial Statements.*
(2) *Includes amounts deferred (20%) pursuant to stock purchase election.*
(3) *Includes amounts deferred (100%) pursuant to stock purchase election.*
(4) *Retired from directorship on September 1, 2006. He received a prorated annual retainer and fees for three quarters of the year based on his time of service.*

Compensation Committee Interlocks and Insider Participation

There are no Compensation Committee interlocks.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth certain information regarding ownership of the Company's common stock as of April 30, 2007, by (a) each person known by the Company to own beneficially more than 5% of the outstanding shares of common stock; (b) each director of the Company; (c) each executive officer; and (d) all directors and executive officers as a group. As of April 30, 2007, 14,887,530 common shares of the Company were issued and outstanding.

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned		Percent of Shares Beneficially Owned
FMR Corporation 82 Devonshire Street Boston, MA 02109	2,420,360	(1)	16.3%
Steinberg Asset Management, LLC 12 East 49th Street New York, NY 10017	2,085,868	(2)	14.0%
Kayne Anderson Rudnick Investment Management, LLC 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	1,078,093	(3)	7.2%
Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 94105	1,029,403	(4)	6.9%
Steven R. Williams	310,931	(5)	2.1%
Thomas E. Riley	104,605	(6)	*
Eric R. Stearns	56,828	(7)	*
Richard W. McCullough	-	(8)	*
Darwin L. Stump	26,540	(9)	*
Vincent F. D'Annunzio	21,042		*
Jeffrey C. Swoveland	12,916		
Kimberly Luff Wakim	4,479		*
David C. Parke	4,129		*
Anthony J. Crisafio	1,035		*
All directors and executive officers as a group (10 persons)(10)	542,505	(11)	3.6%

* Less than 1%

(1) *According to the Schedule 13G filed by FMR Management with the SEC on February 14, 2007.*
(2) *According to the Schedule 13G filed by Steinberg Asset Management with the SEC on February 9, 2007.*
(3) *According to the Schedule 13G filed by Anderson Rudnick Investment Management with the SEC on February 5, 2007.*
(4) *According to the Schedule 13G filed by Barclays Global Investors, NA Management with the SEC on January 23, 2007.*
(5) *Includes 4,814 shares subject to options exercisable within 60 days of April 30, 2007; excludes 19,561 restricted shares subject to vesting.*
(6) *Includes 3,179 shares subject to options exercisable within 60 days of April 30, 2007; excludes 13,971 restricted shares subject to vesting.*
(7) *Includes 2,928 shares subject to options exercisable within 60 days of April 30, 2007; excludes 12,597 restricted shares subject to vesting.*
(8) *Excludes 4,256 restricted shares subject to vesting.*
(9) *Includes 2,605 shares subject to options exercisable within 60 days of April 30, 2007; excludes 9,316 restricted shares subject to vesting.*
(10) *Address: 120 Genesis Boulevard, Bridgeport, WV 26330.*
(11) *Includes 13,526 shares subject to options exercisable within 60 days of April 30, 2007; excludes 59,701 restricted shares subject to vesting.*

Equity Compensation Plan Information

The following table summarizes information related to the Company's equity compensation plans under which its equity securities are authorized for issuance as of April 30, 2007.

Plan category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding	Number of securities remaining available for future issuance under equity compensation plans(1)
Equity compensation plans approved by security holders(2)	59,567 (3)	$ 29.56	530,267
Equity compensation plans not approved by security holders	-	-	-
Total	59,567	$ 29.56	530,267

(1) *Excludes the number of securities to be issued upon exercise of outstanding options and performance shares subject to certain performance goals over a specified period of time.*
(2) *These plans consist of the 1999 Incentive Stock Option and Non-Qualified Stock Option Plan, the 2004 Long-Term Equity Compensation Plan and the 2005 Non-Employee Director Restricted Stock Plan.*
(3) *Excludes 31,972 shares of common stock issuable upon the obtainment of specified performance goals over a specified period of time.*

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Policies and Procedures with Respect to Transactions with Related Persons

The Board has adopted a policy for the review, approval and ratification of transactions that involve related parties and potential conflicts of interest.

The related party transaction policy applies to each director and executive officer of the Company, any nominee for election as a director, any security holder who is known to own more than five percent of the Company's voting securities, any immediate family member of any of the foregoing persons and any corporation, firm or association in which one or more of the Company's directors are directors or officers, or have a substantial financial interest.

Under the related party transaction policy a related person transaction is a transaction or arrangement involving a related person in which the Company is a participant or that would require disclosure in the Company's filings with the SEC as a transaction with a related person.

The related persons must disclose to the Audit Committee any potential related person transactions and must disclose all material facts with respect to such interest. All related person transactions will be reviewed by the Audit Committee. In determining whether to approve or ratify a transaction, the Audit Committee will consider the relevant facts and circumstances of the transaction which may include factors such as the relationship of the related person with the Company, the materiality or significance of the transaction to the Company and the business purpose and reasonableness of the transaction, whether the transaction is comparable to a transaction that could be available to the Company on an arms-length basis, and the impact of the transaction on the Company's business and operations.

During the year ended December 31, 2006, there was no transaction or series of transactions, or any currently proposed transaction, in which the amount involved exceeds $120,000 and in which any director, executive officer, holder of more than 5% of our common stock or any member of the immediate family of any of the foregoing persons had or will have a direct or indirect material interest.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

KPMG Fees

The following table presents the aggregate fees billed to the Company by KPMG LLP ("KPMG") for services in 2006 and 2005 as of March 31, 2007.

	2006	2005
Audit fees	**$ 2,038,701**	$ 2,457,423
Audit related fees	**983,701**	394,543
Total audit and audit related fees[(1)]	**$ 3,022,402**	$ 2,851,966

(1) *There were no tax or other fees for services rendered to us during either of the years.*

Audit Fees

Audit fees include amounts billed for professional services rendered by KPMG for the audit of the Company's annual consolidated financial statements and the report on management's assessment of internal control over financial reporting and the effectiveness of the Company's internal control over financial reporting for the years ended December 31, 2006 and 2005, including reviews of the condensed consolidated financial statements included in the Company's quarterly reports on Form 10-Q for the years ended December 31, 2006 and 2005. The 2005 audit fees also include fees billed for professional services rendered by KPMG for the audit of the consolidated financial statements included in the Company's Form 10-K/A for the year ended December 31, 2004.

Audit Related Fees

Audit related fees include amounts billed for professional services rendered by KPMG for the audits of the annual financial statements of the Company-sponsored drilling partnerships for which the Company acts as managing general partner. The aggregate billings for those professional services rendered during 2006 primarily represent audits for years ended December 31, 2005 and prior. Total audit related fees for the year ended December 31, 2005, includes $140,977 related to due diligence services provided for a contemplated transaction.

Audit Committee Pre-Approval Policies and Procedures

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements:

See Index to Financial Statements and Schedules on page F-1.

(2) Financial Statement Schedules:

See Index to Financial Statements and Schedules on page F-1.

Schedules and Financial Statements Omitted

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

(3) Exhibits:

See Exhibits Index on page E-1.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PETROLEUM DEVELOPMENT CORPORATION

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

May 22, 2007

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

Signature	Title	Date
/s/ Steven R. Williams Steven R. Williams	Chairman, Chief Executive Officer and Director (principal executive officer)	May 22, 2007
/s/ Richard W. McCullough Richard W. McCullough	Chief Financial Officer and Treasurer (principal financial officer)	May 22, 2007
/s/ Darwin L. Stump Darwin L. Stump	Chief Accounting Officer (principal accounting officer)	May 22, 2007
/s/ Thomas E. Riley Thomas E. Riley	President and Director	May 22, 2007
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	May 22, 2007
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	May 22, 2007
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	May 22, 2007
/s/ David C. Parke David C. Parke	Director	May 22, 2007
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	May 22, 2007

Exhibits Index

Exhibit Number	Exhibit Name	Location
3.1	Amended and Restated Certificate of Incorporation of the Company	Incorporated by reference to Exhibit 3.1 to Form S-2, SEC File No. 333-36369, filed on September 25, 1997.
3.2	Amended and Restated By Laws of the Company	Incorporated by reference to Exhibit 3.1 to Form 8-K filed on April 2, 2007.
10.1	Amended and restated Credit Agreement, dated as of November 4, 2005, Petroleum Development Corporation, as borrower, and JPMorgan Chase Bank, N.A. and BNP Paribas, as lenders.	Incorporated by reference to Exhibit 10.2 to Form 8-K dated November 4, 2005.
10.2	Employment Agreement with Steven R. Williams, Chief Executive Officer and Chairman, dated as of March 7, 2003, and amended December 29, 2005	Incorporated by reference in Exhibit 10.2 to Form 10-K filed on March 7, 2003, and Exhibit 99.1 to Form 8-K filed January 4, 2006.
10.3	Employment Agreement with Darwin L. Stump, Chief Accounting Officer, dated as of January 5, 2004, and amended December 29, 2005	Incorporated by reference to Exhibit 99.4 Form 8-K dated January 5, 2004, and Exhibit 99.4 to Form 8-K dated January 4, 2006.
10.4	Employment Agreement with Thomas E. Riley, President, dated as of January 5, 2004, and amended December 29, 2005	Incorporated by reference to Exhibit 99.6 Form 8-K dated January 5, 2004, and Exhibit 99.2 to Form 8-K dated January 4, 2006.
10.5	Employment Agreement with Eric R. Stearns, Executive Vice President, dated as of January 5, 2004, and amended December 29, 2005	Incorporated by reference to Exhibit 99.5 Form 8-K dated January 5, 2004, and Exhibit 99.3 to Form 8-K dated January 4, 2006.
10.6	Employment Agreement with Richard W. McCullough, Chief Financial Officer, dated as of November 13, 2006.	Filed herewith.
10.7	2007 Compensation Arrangements with Executive Officers	Incorporated by reference to Exhibit 99.1 to Form 8-K dated February 20, 2007.
10.8	2007 Long-Term Incentive Program	Incorporated by reference to Exhibit 99.1 to Form 8-K dated February 20, 2007.
10.9	2007 Short-Term Incentive Program	Incorporated by reference to Form 8-K dated April 2, 2007.
10.10	2005 Non-Employee Director Restricted Stock Plan	Incorporated by reference to Exhibit 99.1 to Form S-8, SEC file No. 333-126444 filed on July 7, 2005.

10.11	2004 Long-Term Equity Compensation Plan	Incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-118215, filed on August 13, 2004.
10.12	Non-Employee Director Deferred Compensation Plan	Incorporated by reference Exhibit 99.1 to Form S-8, SEC File No. 333-118222, filed on August 13, 2004.
10.13	1999 Incentive Stock Option and Non-Qualified Stock	Incorporated by reference to Exhibit 99.1 to form S-8, SEC File No. 333-111825, filed on January 9, 2004.
10.14	1997 Employee Incentive Stock Option Plan	Incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-111824, filed on January 9, 2004.
10.15	Tom Carpenter Employment Agreement Stock Option Plan	Incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-111823, filed on January 9, 2004.
14	Code of Business Conduct and Ethics	Incorporated by reference to Exhibit 3.1 to Form 10-K for the year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003.
21.1	Subsidiaries	Filed herewith.
23.1	Consent of Independent Registered Public Accounting Firm	Filed herewith.
23.2	Consent of Independent Petroleum Engineers	Filed herewith.
23.3	Consent of Independent Petroleum Engineers	Filed herewith
31.1	Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer	Filed herewith.
31.2	Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer	Filed herewith.
32.1	Title 18 U.S.C. Section 1350 (Section 906 of Sarbanes-Oxley Act of 2002) Certifications by Chief Executive Officer and Chief Financial Officer	Filed herewith.

PETROLEUM DEVELOPMENT CORPORATION

Index to Consolidated Financial Statements and Financial Statement Schedule

PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Petroleum Development Corporation:

We have audited the accompanying consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2006. In connection with our audits of the consolidated financial statements, we also have audited the related financial statement schedule. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U. S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), ("Share-Based Payment"), in 2006.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of quantifying errors based on SEC Staff Accounting Bulletin No. 108 ("Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements") in 2006.

We also have audited, in accordance with the standards of Public Company Accounting Oversight Board (United States), the effectiveness of Petroleum Development Corporation's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated May 22, 2007, expressed an unqualified opinion on management's assessment of, and an adverse opinion on the effective operation of, internal control over financial reporting as of December 31, 2006.

KPMG LLP
Pittsburgh, Pennsylvania
May 22, 2007

PETROLEUM DEVELOPMENT CORPORATION

Consolidated Balance Sheets

(in thousands, except share and per share data)

December 31,	**2006**	2005
Assets		
Current assets:		
Cash and cash equivalents	**$ 194,326**	$ 90,110
Restricted cash	**519**	1,501
Accounts receivable, net	**42,600**	43,248
Accounts receivable - affiliates	**9,235**	9,041
Inventories	**3,345**	5,055
Fair value of derivatives	**15,012**	10,382
Other current assets	**5,977**	4,640
Total current assets	**271,014**	163,977
Properties and equipment, net	**394,217**	265,926
Restricted/designated cash	**192,451**	-
Goodwill	**6,783**	-
Other assets	**19,822**	14,458
Total Assets	**$ 884,287**	$ 444,361
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	**$ 67,675**	$ 55,049
Short term debt	**20,000**	-
Production tax liability	**11,497**	11,758
Other accrued expenses	**9,685**	4,141
Accounts payable - affiliates	**7,595**	1,479
Deferred gain on sale of leaseholds	**8,000**	-
Federal and state income taxes payable	**28,698**	8,473
Fair value of derivatives	**2,545**	18,424
Advances for future drilling contracts	**54,772**	49,999
Funds held for distribution	**31,367**	31,417
Total current liabilities	**241,834**	180,740
Long-term debt	**117,000**	24,000
Deferred gain on sale of leaseholds	**17,600**	-
Other liabilities	**19,400**	16,184
Deferred income taxes	**116,393**	26,889
Asset retirement obligation	**11,916**	8,283
Total liabilities	**524,143**	256,096
Commitments and contingent liabilities		
Shareholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued 14,834,871 shares and issued and outstanding 16,281,923 shares	**148**	163
Additional paid-in capital	**64**	30,423
Retained earnings	**360,102**	158,504
Unamortized stock award	**-**	(825)
Treasury shares at cost, 4,706 shares	**(170)**	-
Total shareholders' equity	**360,144**	188,265
Total Liabilities and Shareholders' Equity	**$ 884,287**	$ 444,361

See accompanying Notes to Consolidated Financial Statements.

PETROLEUM DEVELOPMENT CORPORATION
Consolidated Statements of Income
(in thousands, except per share data)

Year Ended December 31,	**2006**	2005	2004
Revenues:			
Oil and gas well drilling operations	**$ 17,917**	$ 99,963	$ 94,076
Gas sales from marketing activities	**131,325**	121,104	94,627
Oil and gas sales	**115,189**	102,559	69,492
Well operations and pipeline income	**10,704**	8,760	7,677
Oil and gas price risk management gains (losses), net	**9,147**	(9,368)	(3,085)
Other	**2,221**	2,180	1,696
Total revenues	**286,503**	325,198	264,483
Costs and expenses:			
Cost of oil and gas well drilling operations	**12,617**	88,185	77,696
Cost of gas marketing activities	**130,150**	119,644	92,881
Oil and gas production and well operations cost	**29,021**	20,400	17,713
Exploration cost	**8,131**	11,115	-
General and administrative expense	**19,047**	6,960	4,506
Depreciation, depletion, and amortization	**33,735**	21,116	18,156
Total costs and expenses	**232,701**	267,420	210,952
Gain on sale of leaseholds	**328,000**	7,669	-
Income from operations	**381,802**	65,447	53,531
Interest income	**8,050**	898	185
Interest expense	**(2,443)**	(217)	(238)
Income before income taxes	**387,409**	66,128	53,478
Income taxes	**149,637**	24,676	20,250
Net income	**$ 237,772**	$ 41,452	$ 33,228
Basic earnings per common share	**$ 15.18**	$ 2.53	$ 2.05
Diluted earnings per common share	**$ 15.11**	$ 2.52	$ 2.00

See accompanying Notes to Consolidated Financial Statements.

PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Shareholders' Equity

(in thousands, except share and per share data)

Year Ended December 31,	2006	2005	2004
Common stock - shares issued:			
Shares at beginning of year	**16,281,923**	16,589,824	15,628,433
Adjust prior conversion of predecessor shares	**59,546**	-	-
Exercise of stock options	**8,000**	3,000	1,100,000
Issuance of stock awards, net of forfeitures	**112,902**	20,895	23,380
Retirement of treasury shares	**(1,627,500)**	(331,796)	(161,989)
Shares at end of year	**14,834,871**	16,281,923	16,589,824
Treasury stock:			
Shares at beginning of year	**-**	-	-
Purchase of treasury shares	**(1,627,500)**	(331,796)	(161,989)
Retirement of treasury shares	**1,627,500**	331,796	161,989
Non-employee directors' deferred compensation plan	**(4,706)**	-	-
Shares at end of year	**(4,706)**	-	-
Common shares outstanding	**14,830,165**	16,281,923	16,589,824
Common stock, $.01 par:			
Balance at beginning of year	**$ 163**	$ 166	$ 156
Exercise of stock options	**-**	-	11
Issuance of stock awards, net of forfeitures	**1**	-	-
Retirement of treasury shares	**(16)**	(3)	(1)
Balance at end of year	**148**	163	166
Additional paid-in capital:			
Balance at beginning of year	**30,423**	37,684	28,593
Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)	**(825)**	-	-
Exercise of stock options	**31**	12	4,981
Issuance of stock awards, net of forfeitures	**(1)**	-	-
Stock based compensation expense	**1,516**	603	871
Retirement of treasury shares	**(31,150)**	(7,876)	(4,156)
Excess tax benefit of stock based compensation	**70**	-	7,395
Balance at end of year	**64**	30,423	37,684
Retained earnings:			
Balance at beginning of year	**158,504**	117,052	83,824
Cumulative effect adjustment for the adoption of SAB 108, net of tax	**(1,021)**	-	-
Retirement of treasury shares	**(35,153)**	-	-
Net income	**237,772**	41,452	33,228
Balance at end of year	**360,102**	158,504	117,052
Unamortized stock award			
Balance at beginning of year	**(825)**	(882)	(15)
Issuance of stock awards	**-**	(603)	(871)
Amortization of stock awards	**-**	660	4
Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)	**825**	-	-
Balance at end of year	**-**	(825)	(882)
Treasury stock, at cost:			
Balance at beginning of year	**-**	-	-
Purchase of treasury shares	**(66,319)**	(7,879)	(4,157)
Retirement of treasury shares	**66,319**	7,879	4,157
Non-employee directors' deferred compensation plan	**(170)**	-	-
Balance at end of year	**(170)**	-	-
Total shareholders' equity	**$ 360,144**	**$ 188,265**	**$ 154,020**

See accompanying Notes to Consolidated Financial Statements.

PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Cash Flows

(in thousands)

Year Ended December 31,	2006	2005	2004
Cash flows from operating activities:			
Net income	$ 237,772	$ 41,452	$ 33,228
Adjustments to net income to reconcile to net cash			
provided by (used in) operating activities:			
Deferred income taxes	86,431	3,351	9,887
Depreciation, depletion and amortization	33,735	21,116	18,156
Impairment of oil and gas properties	1,519	-	-
Accretion of asset retirement obligation	515	465	436
Dry hole costs	1,790	11,115	-
Gain from sale of leaseholds	(328,000)	(7,669)	-
Loss (gain) from sale of assets	9	(207)	(32)
Expired and abandoned leases	2,169	48	301
Amortization of stock award	1,516	660	4
Unrealized (gains) losses on derivative transactions	(7,620)	3,226	535
Changes in current assets and liabilities:			
Decrease (increase) in restricted cash	982	(836)	1,201
Increase in accounts receivable	(9,935)	(11,811)	(11,391)
Increase in accounts receivable - affiliates	(194)	(5,319)	(1,482)
Decrease (increase) in inventories	1,987	(3,398)	357
(Increase) decrease in other current assets	(2,106)	3,482	4,776
(Decrease) increase in production tax liability	(261)	3,317	8,441
Increase in accounts payable and accrued expenses	13,010	19,440	11,648
Increase in accounts payable - affiliates	6,116	112	745
Increase (decrease) in advances for future drilling contracts	4,773	7,502	(7,961)
Increase in federal and state income taxes payable	19,880	8,473	-
(Decrease) increase in funds held for future distribution	(575)	18,505	4,501
Other	3,877	(652)	(49)
Net cash provided by operating activities	67,390	112,372	73,301
Cash flows from investing activities:			
Capital expenditures	(146,180)	(97,390)	(44,762)
Acquisition of Unioil, net of cash acquired	(18,512)	-	-
Investment in drilling partnerships	(7,151)	(7,160)	3,540
Exploration costs	(765)	(1,918)	(4,170)
(Increase) decrease in restricted/designated cash	(192,416)	-	-
Proceeds from sale of leases to partnerships	1,798	2,829	1,951
Proceeds from sale of leaseholds/assets	353,600	9,597	95
Net cash provided by (used in) investing activities	(9,626)	(94,042)	(43,346)
Cash flows from financing activities:			
Proceeds from debt	302,000	91,000	84,000
Proceeds from short-term debt	20,000	-	-
Retirement of debt	(209,000)	(88,000)	(116,000)
Payment of debt issuance costs	(160)	(423)	(233)
Proceeds from issuance of stock	31	12	3,584
Excess tax benefits from stock-based compensation	70	-	-
Purchase of treasury stock	(66,489)	(7,879)	(2,749)
Net cash provided by (used in) financing activities	46,452	(5,290)	(31,398)
Net increase (decrease) in cash and cash equivalents	104,216	13,040	(1,443)
Cash and cash equivalents, beginning of period	90,110	77,070	78,513
Cash and cash equivalents, end of period	$ 194,326	$ 90,110	$ 77,070
Supplemental disclosures of cash flow information:			
Cash paid during the period for:			
Income taxes	$ 46,735	$ 10,675	$ 5,028
Interest	$ 3,011	$ 101	$ 1,049

See accompanying Notes to Consolidated Financial Statements.

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Petroleum Development Corporation ("PDC" or "the Company") is an independent energy company engaged primarily in the drilling and development, production and marketing of natural gas and oil. Since it began oil and gas operations in 1969, the Company has grown primarily through drilling and development activities, the acquisition of producing natural gas and oil wells and the expansion of its natural gas marketing activities. As of December 31, 2006, the Company operates approximately 3,100 wells located in the Appalachian Basin, Michigan, and the Rocky Mountain Region. All of the Company's oil and gas wells are located in West Virginia, Tennessee, Pennsylvania, Michigan, North Dakota, Colorado, Kansas and Wyoming. The Company's operations are divided into four business segments: drilling and development, natural gas marketing, oil and gas sales and well operations and pipeline income. See Note 17.

Principles of Consolidation

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

Cash Equivalents

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

Restricted and Designated Cash

In July 2006, the Company established a trust in the amount of $300 million with a qualified intermediary in conjunction with its sale of undeveloped leaseholds and corresponding "like-kind exchange" agreement. As of December 31, 2006, $300 million remains in the trust, with $109 million reflected in cash and cash equivalents as a current asset in the consolidated balance sheet and the remaining $191.5 million reflected as designated cash – property acquisitions, a non-current asset. The $191.5 million represents the amounts paid in January 2007 for the acquisition of oil and gas properties qualifying for "like-kind exchange" treatment. Interest earned on the trust account of $5.5 million is reflected in cash and cash equivalents as a current asset, along with the $109 million not utilized for "like-kind exchange" ("LKE") purchases, will be available to the Company for operating purposes in January 2007 and is no longer subject to a LKE. See Note 15 and Note 16.

In December 2006, the Company had paid a deposit of $0.5 million, reflected in the consolidated balance sheet as designated cash, a non-current asset, for the acquisition of oil and gas properties subsequently closed in January 2007.

The Company is required to maintain margin deposits with brokers for outstanding derivative contracts. As of December 31, 2006 and 2005, cash in the amount of $0.5 million and $1.5 million, respectively, was on deposit and reflected in the consolidated balance sheets as restricted cash, a current asset.

The Company is required by various government agencies or joint venture agreements to maintain a bond or cash account for the plugging and abandonment of wells. As of December 31, 2006, the Company had bonds and cash accounts restricted for plugging and abandonment of wells totaling $1.0 million, which are reflected in restricted/designated cash, a non-current asset.

Inventories

Materials, supplies and commodity inventories are stated at the lower of average cost or market and removed at carrying value.

Oil and Gas Properties

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

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing its reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of the Company's financial statements, the costs are expensed to exploration costs. If management is unable to make a final determination about the productive status of a well prior to issuance of the Company's financial statements, the cost of the well is classified as part of "Suspended Well Costs" until management has had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when management is able to make a final determination of a well's productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded based on that determination. The determination of an exploratory well's ability to produce is generally made within one year from the completion of drilling activities. See Note 18.

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

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

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which management reasonably estimates such production to be sold. These estimates of future production prices may differ from current market prices of oil and gas. Any downward revisions to management's estimates of future production or prices could result in an impairment of the Company's oil and gas properties in subsequent periods. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows. In 2006, the Company recognized an impairment loss on oil and gas properties of $1.5 million, which is included in the statement of income as a component of exploration cost.

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, long-lived assets, such as property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset.

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

Capitalized Interest

Interest costs are capitalized as part of the historical cost of acquiring assets. Oil and gas investments in unproved properties and major development projects, on which depreciation, depletion and amortization expense is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready for service. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on its debt by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is moved to the depreciation, depletion and amortization pool, the related capitalized interest is also transferred and is amortized over the useful life of the asset. Interest costs of $1.6 million were capitalized during 2006. No interest costs were capitalized during 2005 or 2004.

Goodwill

Goodwill represents the excess of the aggregate purchase price over the fair value of the net assets acquired in a purchase business combination. The acquisition of Unioil in December 2006 resulted in the recognition of goodwill in the amount of $6.8 million. The goodwill has been allocated to the oil and gas sales segment. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill will be tested at least annually for impairment. See Note 2.

Buildings

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

Asset Retirement Obligations

The Company accounts for asset retirement obligations by recording the fair value of its plugging and abandonment obligations when incurred, which is at the time the well is completely drilled. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to oil and gas production and well operations costs. The initial capitalized costs are depleted over the useful lives of the related assets, through charges to depreciation, depletion and amortization. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations. See Note 7 for a reconciliation of asset retirement obligation activity.

Production Tax Liability

Production tax liability represents estimated taxes, primarily severance and property, to be paid to the states and counties in which the Company produces oil and gas. The Company's share of these taxes is expensed to oil and gas production and well operations cost.

Advances for Future Drilling Contracts

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

Retirement of Treasury Shares

The Company has historically retired all treasury share purchases, with the exception of shares purchased in accordance with its non-employee deferred compensation plan for non-employee directors, see Note 9. As treasury shares are retired, the Company charges any excess of cost over the par value entirely to additional paid-in-capital, to the extent the Company has amounts in paid-in-capital, with any remaining excess cost being charged to retained earnings.

Revenue Recognition

The Company's drilling segment recognizes revenue from drilling contracts with sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. In addition, the Company offers its drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships, and hence, different revenue reporting policies pursuant to Emerging Issues Task Force (“EITF”) No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.*

The first cost-plus drilling service arrangement was initially entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Although the Company acts as a principal in the transaction and takes title to products and services acquired necessary for drilling, the Company acts as an agent, with little risk of loss during the performance of the drilling activities. Consistent with the provisions of EITF 99-19, the Company's services provided under the cost-plus drilling agreements are reported net of recovered costs. The Company entered into its second cost-plus drilling arrangement in September 2006 and commenced drilling immediately. It is the Company's intent that all future drilling arrangements will be on a cost-plus basis.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are generally completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services and accordingly has risk of loss in performing services under these arrangements. Accordingly, the Company reports revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that the estimated total costs exceed the estimated total contract revenue. At December 31, 2006 and 2005, the loss contract reserve was $0.3 million and $0.8 million, respectively.

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

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

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

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

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

Income Taxes

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

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

Derivative Financial Instruments

The Company accounts for derivative financial instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Certain Hedging Activities*, as amended.

During 2006, 2005 and 2004, none of the Company's derivative instruments qualified for use of hedge accounting under the terms of SFAS No. 133. Accordingly, the Company recognizes all derivative instruments as either assets or liabilities on the consolidated balance sheets at fair value and changes in the derivatives' fair values are recorded in the consolidated statements of income in oil and gas price risk management, net for the Company's oil and gas commodities (derivatives related to the Company's production only), in gas sales from marketing activities for RNG's gas sales, in cost of gas marketing activities for RNG's gas purchases and in interest expense for the Company's interest rate swap (2004 only), as applicable. See Note 14.

In the accompanying consolidated balance sheets, the Company records the fair value of derivatives entered into on behalf of the affiliated partnerships and records an offsetting receivable from or payable to the partnerships. See Note 11.

Stock-Based Compensation

Effective January 1, 2006, the Company adopted Statement SFAS No. 123(R), *Share-Based Payment (revised 2004)*. The Company elected the modified prospective method of adoption, and accordingly, prior period financial statements have not been restated. Pursuant to SFAS No. 123(R) the Company is required to recognize in its financial statements, based on fair value, compensation expense for all unvested stock options and other equity-based awards as of January 1, 2006. For all unvested options outstanding as of January 1, 2006 the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in the financial statements over the remaining requisite service period for each separately vesting portion. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in the financial statements on a straight-line basis over the vesting period for the entire award. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, such amounts are capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the appropriate cost and expense line item in the statement of income. For the year ended December 31, 2006, the Company recognized stock-based compensation expense of $0.1 million and $1.4 million related to stock option and restricted stock awards, respectively. Compensation capitalized as part of properties and equipment was immaterial in 2006.

For periods prior to the adoption of SFAS No. 123(R), the Company accounted for its share-based compensation awards using the intrinsic value based method as prescribed by Accounting Principles Board Opinion ("APB") No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under the intrinsic value based method, compensation expense for option awards was recorded on the date of grant only if the then-current market price of the underlying stock exceeded the exercise price. The following table illustrates the effect on net income and earnings per share had the Company applied the fair value recognition provisions of SFAS No. 123(R), as amended, to stock-based employee compensation during 2005 and 2004 (in thousands, except per share data):

	Year ended December 31,	
	2005	2004
Net income, as reported:	$ 41,452	$ 33,228
Stock-based compensation expense included in reported net income, net of tax	414	2
Total stock-based compensation expense determined under fair value method for all awards, net of tax	(509)	(21)
Pro forma net income	$ 41,357	$ 33,209
Earnings per share:		
Basic earnings per share, as reported and pro forma	$ 2.53	$ 2.05
Diluted earnings per share, as reported and pro forma	$ 2.52	$ 2.00

Earnings Per Share

The Company's basic earnings per share ("EPS") amounts have been computed based on the average number of shares of common stock outstanding for the period. Diluted EPS amounts include the effect of the Company's outstanding stock options, unamortized portion of restricted stock and shares held pursuant to the Company's non-employee director deferred compensation plan using the treasury stock method if including such potential shares of common stock is dilutive. See Note 10.

Use of Estimates

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles in the United States of America requires management of the Company to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and gas reserves, future cash flows from oil and gas properties valuation of derivative instruments and valuation of deferred income tax assets.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and debt obligations approximate fair value as of December 31, 2006 and 2005, due to the short-term maturity of these instruments.

Reclassifications

Reclassifications to conform to current year presentation

Certain prior year amounts were reclassified to conform to the current year presentation. The reclassifications had no impact on reported net earnings, earnings per share, shareholders' equity or cash flows from operating activities.

- Oil and gas price risk management losses of $9.4 million and $3.1 million for 2005 and 2004, respectively, have been reclassified from non-operating losses to a component of (and an offset to) revenues.
- As of December 31, 2005, investment in drilling partnerships, a long-term asset, in the amount of $11.2 million has been reclassified from properties and equipment, net, also a long-term asset, to other long-term assets.

Reclassifications to correct prior year amounts

Certain prior year amounts were reclassified to correct prior year amounts. These correcting reclassifications were immaterial and had no impact on reported net earnings, earnings per share, shareholders' equity or cash flows from operating activities.

- Accretion expense related to the Company's asset retirement obligation in the amount of $0.5 million and $0.4 million, respectively for the years 2005 and 2004, has been reclassified from interest expense, a non-operating expense, to oil and gas production and well operations cost, a component of income from operations.
- Interest income in the amount of $0.9 million, and $0.2 million, respectively for the years 2005 and 2004, has been reclassified from other income, a component of revenues, to interest income, a non-operating income item.
- Gain on sale of leaseholds in the amount of $7.7 million for the year 2005 has been reclassified from other income to gain on sale of leaseholds, with no impact on income from operations.
- As of December 31, 2005, production taxes relating to accrued oil and gas revenues in the amount of $3.8 million previously reported as a reduction of accounts receivable have been reclassified to production tax liability.
- As of December 31, 2005, production receivables in the amount of $1.8 million were reclassified from accounts receivable to accounts receivable - affiliates.
- As of December 31, 2005, the Company did not appropriately eliminate a portion of its intercompany accounts receivable and accounts payable; accordingly, the Company reduced it accounts receivable and accounts payable balances by $8.5 million, resulting in the elimination of all material intercompany transactions.
- In connection with the production tax withheld adjustment discussed below under the caption Recently Adopted Accounting Standards, $22.1 million has been reclassified from production tax liability to other liability line items as of December 31, 2005. Of this amount, $9.1 million has been reclassified to other long-term liability to reflect production tax obligations as of December 31, 2005, that are not payable until 2007 and $13 million, representing amounts due to drilling partnership limited partners as a result of over withholding of estimated production taxes by the Company, has been reclassified to funds held for distribution.

Recent Accounting Standards

Recently Adopted Accounting Standards

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), *Share-Based Payment*. In March 2005, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin ("SAB") No. 107, *Share-Based Payment*, regarding the interaction between SFAS No. 123(R) and certain SEC rules and regulations. Effective January 1, 2006, the Company adopted SFAS No. 123(R). The Company elected to use the modified prospective method for adoption, which requires compensation expense to be recognized in the statement of income for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Prior to the adoption of SFAS No. 123(R), the Company followed the intrinsic value method in accordance with APB No. 25 (as amended) to account for employee stock-based compensation. The adoption of SFAS No. 123(R) required the unamortized stock award recorded under APB No. 25 related to stock-based compensation awards as of January 1, 2006, in the amount of $0.8 million to be eliminated against additional paid-in-capital. See *Stock-Based Compensation* policy above and Note 8 for further discussion of the Company's accounting for share-based compensation awards.

In June 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statement No. 3*, which replaces APB No. 20, *Accounting Changes*, and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements*, and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle in addition to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 became effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The January 1, 2006, adoption of SFAS No. 154 did not have a material impact on the Company's consolidated financial statements.

In September 2006, the SEC issued SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB No. 108 provides guidance on how the effects of prior year misstatements should be considered in quantifying misstatements in the current year financial statements. SAB No. 108 requires registrants to quantify misstatements using both the income statement ("rollover") and balance sheet ("iron curtain") approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. Historically, the Company evaluated uncorrected misstatements using the "rollover" method which resulted in an accumulation of quantitatively and qualitatively immaterial misstatements to the Company's consolidated financial statements. SAB No. 108 provides for a one time transitional adjustment to retained earnings for errors which were not deemed material to prior year financial statements, but which are material under guidance of SAB No. 108. The Company adopted SAB No. 108 during the fourth quarter of 2006 and recorded the effect of the following identified items as a cumulative effect adjustment to retained earnings effective January 1, 2006 for periods through December 31, 2005 (in thousands):

	Increase/ (Decrease)
Pre-tax adjustments:	
Employee benefits payable (1)	$ (470)
Accrued performance supplement (2)	(464)
Deferred compensation retirement liability (3)	(961)
Accounting for oil inventory (4)	(1,172)
Fair value of derivatives (5)	(487)
Oil and gas properties, net (6)	(1,402)
Funds held for distribution (7)	(778)
Funds held pending a division order (8)	377
Interest income recognition (9)	136
Accrued gas marketing (10)	(15)
Accrued oil and gas production costs (11)	878
Unclaimed property liabilities (12)	(124)
Production taxes withheld (13)	5,003
Accrued franchise tax (14)	(52)
Prepaid well costs (15)	(274)
Accrued production taxes (16)	(1,445)
	(1,250)
Tax effect (17)	229
Decrease to shareholders' equity as of January 1, 2006	$ (1,021)

(1) *Employee benefits payable – The Company understated employee benefits payable as a result of errors in its calculation of certain 401k plan provisions. These errors originated in 1997 and continued through December 31, 2005.*

(2) *Oil and gas partnership performance liability – The Company understated oil and gas partnership performance liability as a result of recognizing its cost on a cash basis instead of accruing the cost in the period in which the cost was incurred. This misstatement originated in 1996 and continued through June 30, 2006.*

(3) *Deferred compensation retirement liabilities – The Company understated its deferred compensation and medical benefits liability as a result of errors in the calculation of the escalation provision in the deferred compensation plan and understated its post retirement medical benefits liability as a result of recognizing its cost on a cash basis for certain employment contracts. This misstatement originated in 2000 and continued through September 30, 2006.*

(4) *Accounting for oil inventory – The Company overstated accounts receivable and understated its inventory as a result of recognizing oil revenues when production was delivered to Company owned storage tanks. This misstatement originated in 1999 and continued through September 30, 2006.*

(5) *Fair value of derivatives – The Company overstated the fair value of its purchase of certain put option contracts as a result of errors in its premium amortization calculation. This misstatement originated in 2005 and continued through September 30, 2006.*

(6) *Oil and gas properties, net – The Company capitalized certain overhead cost which, under the successful efforts method of accounting for oil and gas properties, should have been expensed in the period incurred. This misstatement originated in 2001 and continued through September 30, 2006.*

(7) *Funds held for distribution liability – The Company understated its funds held for distribution liability as a result of errors in the processing of certain transactions and un-reconciled differences between certain control and subsidiary accounts. This misstatement originated in years prior to 2002 and continued through September 30, 2006.*

(8) *Funds held pending a division order – The Company overstated its funds held for distribution liability and understated its portion of oil and gas revenue and corresponding production taxes as a result of not accruing oil and gas production proceeds that had been received but held for distribution due to a lack of a division order. This misstatement originated in years prior to 2002 and continued through September 30, 2006.*

(9) *Accrued interest income – The Company understated accounts receivable affiliates as a result of recognizing the Company's portion of affiliate interest income on a cash basis. This misstatement originated in 2005 and continued through September 30, 2006.*

(10) *Gas marketing liabilities – The Company understated gas marketing liabilities as a result of errors in its calculation of the timing of services provided. This misstatement originated in 2004 and continued through September 30, 2006.*

(11) *Accrued oil and gas production costs – The Company overstated production tax liability, a current liability, by over accruing fuel usage costs. This misstatement originated in 2003 and continued through September 30, 2006.*

(12) *Unclaimed property liability – The Company understated accrued expenses as a result of errors in its calculation of unclaimed property liability. This misstatement originated in 1995 and continued through September 30, 2006.*

(13) *Production taxes withheld - The Company over-withheld production tax obligations related to oil and gas production proceeds distributed by the Company in years prior to 2002 to September 30, 2006. As a result, the Company overstated its oil and gas production and well operations cost and, in its capacity as well operator, the Company over-withheld from the revenue distributions made to drilling partnership limited partners (see reclassification above). The Company has accrued and will distribute foregone interest to the limited partners and has also accrued estimated penalties and interest that are likely to result from this item. This misstatement originated in 2001 and continued through September 30, 2006.*

(14) *Franchise tax liabilities – The Company understated franchise tax liabilities as a result of recognizing certain of its liabilities on a cash basis. This misstatement originated in 2005 and continued through September 30, 2006.*

(15) *Prepaid well costs – The Company overstated prepaid well costs as a result of errors in accounting for the expiration and abandonment of well drill sites. This misstatement originated in 2004 and continued through September 30, 2006.*

(16) *Accrued production taxes – The Company understated production tax liabilities as a result of not accruing penalty and interest associated with the untimely payment of production taxes in certain jurisdictions and not correcting other unreconciled amounts included in production tax liabilities. This misstatement originated in 2001 and continued through September 30, 2006.*

(17) *Tax effect - As a result of the errors discussed in items 13 and 16 above, and the fact that certain property and severance taxes were remitted late, the Company expects that it will incur non-deductible penalties. These penalties are not deductible for tax purposes and consist of $0.3 million for the late payment and/or late filing of severance taxes, as well as, income tax penalties of $0.4 for the late payment of the limited partners' income*

taxes that resulted from the overstatement of production costs. After adjusting for the impact of these non-deductible items, the Company recorded a tax provision for the net effect of items 1 through 16 at the rate of 38.8%.

See Note 19, where the effect of the above entries on 2006 quarterly financial statements, which was not material, is reflected in revised financial data for those periods.

Recently Issued Accounting Standards

In June 2006, the FASB issued EITF No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation).* EITF 06-3 addresses the income statement presentation of any tax collected from customers and remitted to a government authority and concludes that the presentation of taxes on either a gross basis or a net basis is an accounting policy decision that should be disclosed pursuant to APB No. 22, *Disclosures of Accounting Policies*. For taxes that are reported on a gross basis (included in revenues and costs), EITF 06-3 requires disclosure of the amounts of those taxes in interim and annual financial statements, if those amounts are significant. EITF 06-3 is effective for interim and annual reporting periods beginning after December 15, 2006. The adoption of the standard, effective January 1, 2007, is not expected to have a significant impact on the consolidated financial statements.

In July 2006, the FASB issued FASB Interpretation ("FIN") No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109*, which prescribes a comprehensive model for accounting for uncertainty in tax positions. FIN No. 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service, based on the technical merits of the position. The provisions of FIN 48 will become effective for the Company as of January 1, 2007. The cumulative effect, if any, of applying the provisions of FIN 48 will be accounted for as an adjustment to retained earnings in the first quarter of 2007. The Company is currently evaluating the impact of adopting FIN 48 on its consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Accounting for Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value within generally accepted accounting principles and expands required disclosure about fair value measurements. SFAS No. 157 does not expand the use of fair value in any new circumstances. The provisions of SFAS No. 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect the new standard to have any material impact on its consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. The Company is evaluating the impact of the adoption of SFAS No. 159 on the financial statements.

NOTE 2 – ACQUISITION OF UNIOIL

On December 6, 2006, the Company completed its cash tender offer and purchased approximately 95.5% or 9,112,750 shares of the outstanding common stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The acquisition of more than 90% of the outstanding shares of common stock allowed the Company to effect a short-form merger of Unioil and a wholly owned subsidiary of the Company, resulting in the acquisition of the remaining 428,719 shares of Unioil. Each share of Unioil common stock not tendered through the offer was converted into the right to receive $1.91 in cash, the same consideration paid for shares in the tender offer. The total price paid for 100% of Unioil's outstanding common stock was $18.6 million, including $0.4 million in direct costs of the acquisition. The acquisition was accounted for in accordance with SFAS No. 141, *Business Combinations*.

The total acquisition cost has been initially allocated to the assets purchased and the liabilities assumed based upon the fair values on the date of acquisition as follows (in thousands):

Cash consideration paid	$ 18,224
Plus: Direct costs of acquisition	382
Total acquisition cost	$ 18,606
Current assets acquired	$ 660
Properties and equipment acquired	19,056
Goodwill	6,783
Deferred tax liability	(6,783)
Other liabilities assumed	(1,110)
Total acquisition cost	$ 18,606

The assessment of the fair values of oil and gas properties acquired was based primarily on projections of expected future net cash flows, discounted to present value. The preliminary acquisition cost allocation includes $6.8 million in goodwill. The goodwill is neither deductible for tax purposes, nor amortizable for book purposes pursuant to SFAS No. 141. Goodwill will be tested for impairment at least annually. The purchase price allocation is preliminary subject to finalizing fair value appraisals and completing evaluations of proved and unproved oil and gas properties. These amounts are subject to change as additional information becomes available and is assessed by the Company.

The results of Unioil's operations have been included in the consolidated financial statements from the date of acquisition, December 6, 2006. The pro forma effect of the inclusion of the results of Unioil's operations in the Company's consolidated statements of income was not material.

NOTE 3 – ACCOUNTS RECEIVABLE

Accounts receivable are reviewed to determine which are doubtful of collection. In making the determination of the appropriated allowance for doubtful accounts, management considers the Company's historical write-offs, relationships and overall credit worthiness of its customers, additional consideration is given to well production data for receivables related to well operations. The allowance as reflected in the accompanying balance sheets is the Company's best estimate of the amount of probable credit losses in the Company's existing accounts receivable.

The allowance for doubtful accounts receivable, net as of December 31, 2006 and 2005, was $0.2 million and $0.2 million, respectively. In addition, included in other assets, a non-current asset, based on their terms, are accounts receivable as of December 31, 2006 and 2005, in the amounts of $0.2 million and $0.4 million, net of an allowance for doubtful accounts of $0.2 million and $0.2 million, respectively.

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of oil and gas sales to a few customers. The Company sells oil and natural gas to various public utilities, gas marketers and industrial customers. The following table identifies significant customers as a percent of total oil and gas sales and total revenues for each of the years presented.

	Oil and Gas Sales			Total Revenue		
	Year Ended December 31,			Year Ended December 31,		
	2006	2005	2004	**2006**	2005	2004
Customer						
A	**14.9%**	10.5%	7.6%	**12.9%**	6.9%	4.3%
B	**10.6%**	10.6%	9.6%	**9.1%**	6.9%	5.4%
C	**10.3%**	15.2%	11.1%	**8.9%**	9.9%	6.3%
D	**9.4%**	12.9%	13.8%	**8.1%**	8.4%	7.8%

NOTE 4 – PROPERTIES AND EQUIPMENT (in thousands)

	December 31, 2006	December 31, 2005
Properties and Equipment:		
Oil and gas properties (successful efforts method of accounting)	**$ 500,506**	$ 354,147
Pipelines	**12,673**	11,512
Transportation and other equipment	**7,870**	6,383
Land and buildings	**11,620**	3,981
Construction in progress	**4,801**	1,509
	537,470	377,532
Less accumulated depreciation, depletion and amortization	**143,253**	111,606
Properties and equipment, net of accumulated depreciation, depletion and amortization	**$ 394,217**	$ 265,926

NOTE 5 - LONG-TERM DEBT

The Company has a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. The current borrowing base, based upon current oil and gas reserves, is $135 million. Effective September 18, 2006, the Company elected to increase the amount it had activated by $55 million, from $80 million to $135 million. The Company is required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an Alternative Base Rate ("ABR") or adjusted LIBOR at the discretion of the Company. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus 0.5%. ABR borrowings are assessed an additional margin spread of 0% to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the facility. No principal payments are required until the credit agreement expires on November 4, 2010.

On December 19, 2006, the Company executed pursuant to its credit facility an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.80% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January, 2007.

As of December 31, 2006 and 2005, the outstanding balance under the facility, including the overline note, was $137 million and $24 million, respectively. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. At December 31, 2006, an outstanding balance of $67 million was subject to a prime interest rate of 8.375%; the overline note in the amount of $20 million was subject to an interest rate of 9.05% and the remaining outstanding balance of $50 million was subject to a LIBOR rate of 7.0%. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves and the maintenance of certain working capital and tangible net worth ratios. As of the filing of this annual report on Form 10-K, the Company was in compliance with all covenants in the credit agreement except for timely filing of this December 31, 2006, Form 10-K. During March 2007, due to various reporting and processing delays, the Company requested a waiver related to the Security assignment provisions of its credit facility. During March 2007, a waiver was granted and the corresponding Borrowing Base was reduced to $100 million from $135 million. Along with the previously discussed waiver, the Company requested and was granted a waiver related to the delay in the delivery of its consolidated financial statement for the year ended December 31, 2006, and three months ended March 31, 2007, until May 31, 2007, and June 30, 2007, respectively.

NOTE 6 - INCOME TAXES

The Company had a substantial taxable gain from the sale of undeveloped oil and gas properties (see Note 15). The Company has chosen to use the favorable deferral aspects of the Internal Revenue Code ("IRC") Section 1031, LKE to defer the tax liability on a portion of the gain utilized by purchasing replacement properties (see Note 16). Accordingly, the Company's current and deferred provision for income taxes increased substantially in 2006 and consisted of the following (in thousands):

	2006	2005	2004
Current:			
Federal	**$ 54,467**	$ 17,894	$ 8,650
State	**8,739**	3,431	1,713
Total current income taxes	**63,206**	21,325	10,363
Deferred:			
Federal	**74,003**	2,834	8,430
State	**12,428**	517	1,457
Total deferred income taxes	**86,431**	3,351	9,887
Total income taxes	**$ 149,637**	$ 24,676	$ 20,250

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

	2006	2005	2004
Computed "expected" tax	**$ 135,594**	$ 23,145	$ 18,717
State income tax	**13,744**	2,566	2,061
Percentage depletion	**(545)**	(771)	(649)
Domestic production activities deduction	**-**	(399)	-
Other	**844**	135	121
	$ 149,637	$ 24,676	$ 20,250

The Company did not have any net income from Qualified Production Activities ("QPAI"), due to its tax filing election to expense the majority of its intangible drilling costs incurred in 2006. Accordingly, the domestic production activities deduction, which is statutorily equal to three percent of QPAI, was zero for 2006.

The Internal Revenue Service ("IRS") has proposed certain adjustments to the Company's federal tax returns for 2003 and 2004. The Company has entered into an agreement with the IRS concerning some of the proposed adjustments and has reached an informal understanding with the IRS regarding the others. The additional federal and state tax expense, including interest, totals approximately $0.6 million, which was accrued for primarily in prior periods. In addition, the proposed adjustments also result in the current taxation in 2003 and 2004 of items previously deferred. Accordingly, as of December 31, 2006, the Company has accrued a current federal and state tax liability of $4.6 million, including applicable interest, which will be due upon completion of the IRS audit.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2006 and 2005, are presented below (in thousands).

	2006	2005
Deferred tax assets:		
Allowance for doubtful accounts	**$ 161**	$ 159
Drilling notes	**46**	71
Deferred revenue related to cash withheld for future plugging cost	**929**	824
Deferred compensation	**2,105**	904
Asset retirement obligations	**4,428**	3,242
Derivatives	**-**	1,562
Employee benefits	**798**	-
Other	**-**	8
Total gross deferred tax assets	**8,467**	6,770
Less valuation allowance	**-**	-
Deferred tax assets	**8,467**	6,770
Deferred tax liabilities:		
Properties and equipment, principally due to differences in depreciation and amortization	**(58,790)**	(31,811)
Like kind exchange - deferred gain	**(63,783)**	-
Unrealized gains - derivatives	**(1,203)**	-
Total gross deferred tax liabilities	**(123,776)**	(31,811)
Net deferred tax liability	**$ (115,309)**	$ (25,041)
Classification in the Consolidated Balance Sheets:		
Net current deferred tax assets*	**$ 1,084**	$ 1,848
Net non-current deferred tax liability	**(116,393)**	(26,889)
Net deferred tax liability	**$ (115,309)**	$ (25,041)

*included in other current assets

As noted above, deferred tax liabilities increased substantially in 2006 due to the Company's utilization of the like-kind exchange tax deferral for a portion of the taxable gain on the undeveloped land sale (Note 15). The deferred tax liability on property and equipment increased primarily as a result of the election to expense, for current tax purposes, approximately $55 million of intangible drilling costs. In addition, approximately $6.8 million of the increase in the deferred liability is due to the Unioil acquisition.

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

NOTE 7 - ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with the Company's working interest in oil and gas properties are as follows (in thousands):

	2006	2005
Balance at beginning of year	**$ 8,333**	$ 7,998
Obligations assumed with development activities and acquisitions	**1,264**	302
Obligations discharged with disposed properties and asset retirements	**(115)**	(446)
Accretion expense	**515**	465
Revisions to estimated cash flows	**1,969**	14
Balance at end of year	**$ 11,966**	$ 8,333

If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Approximately $50,000 of the asset retirement obligations were classified as short-term and included in other accrued expenses as of December 31, 2006 and 2005.

NOTE 8 - COMMON STOCK

Stock-Based Compensation Plans

Approved by the shareholders in June 2004, the Company maintains a long-term equity compensation plan for officers and certain key employees of the Company (the "2004 Plan"). In accordance with the plan, awards may be issued in the form of stock options, stock appreciation rights, restricted stock or performance shares. A total of 750,000 new shares of common stock have been reserved for issuance. Awards pursuant to the plan vest over periods set at the discretion of the Compensation Committee of the Company's Board of Directors ("Board") and have a maximum exercisable period of ten years. As of December 31, 2006, 565,702 common shares remain available for future awards.

Approved by the shareholders in June 2005, the Company also maintains a restricted stock plan for non-employee directors. A total of 40,000 new shares of common stock have been reserved for issuance under the plan. Awards pursuant to the plan are subject to restrictions ending on the earliest of various retirement or termination dates, including certain provisions for change in control. During 2006 and 2005, 6,551 and 6,895 common shares, respectively, were awarded in accordance with the plan. Compensation expense for each of the years ended December 31, 2006 and 2005, related to these restricted shares was $0.1 million. As of December 31, 2006, 26,554 common shares remain available for future awards.

In August 1999, the shareholders approved the 1999 Incentive Stock Option and Non-Qualified Stock Option Plan. A total of 500,000 shares of the Company's common stock were reserved for issuance upon the exercise of stock options. All shares authorized to be awarded pursuant to this plan were awarded in years prior to 2002. At December 31, 2006, options for 49,000 common shares remain outstanding and exercisable through 2011, at which time the options will expire.

Stock Option Awards. The Company granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. The Company did not grant any stock option awards in 2005. The fair values of stock options granted during the years ended December 31, 2006 and 2004, were estimated at the date of grant using a Black-Scholes option-pricing model assuming no dividends and the following weighted average assumptions:

	For the year ended December 31,	
	2006	2004
Expected Volatility	40.4%	39.7%
Expected term (in years)	6	7
Risk-free interest rate	4.2%	4.1%
Weighted-average grant date fair value per share	$20.30	$16.75

Expected volatilities are based on the Company's historical volatility. The expected life of an award is estimated using historical exercise behavior data. The risk-free interest rate is based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the expected life of the award. The Company does not expect to pay dividends, nor does it expect to declare dividends in the foreseeable future.

The following table provides a summary of the Company's stock option award activity for the year ended December 31, 2006:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term *(years)*
Outstanding at December 31, 2005	73,880	$ 11.96	
Granted	23,687	44.76	
Exercised	(8,000)	3.88	
Outstanding at December 31, 2006	**89,567**	**21.36**	**5.6**
Vested and expected to vest at December 31, 2006	**85,808**	**20.32**	**5.4**
Exercisable at December 31, 2006	**57,440**	**9.38**	**3.7**

(in millions)	Year Ended December 31, **2006**	2005	2004
Total intrinsic value of options exercised	**$ 0.3**	$ 0.1	$ 27.6
Total intrinsic value of options outstanding	**2.0**	1.6	2.1
Total intrinsic value of options exercisable	**1.9**	1.6	2.0

The intrinsic value of options exercised represents the amount by which the market value of the Company’s stock at date of exercise exceeds the exercise price of the option. The intrinsic values of the options outstanding and exercisable represent the amount by which the closing market price of the Company’s common stock at the last trading day of the year exceeds the exercise price of the options.

Total unrecognized compensation cost related to stock options granted under the 2004 Plan was $0.5 million as of December 31, 2006. This cost is expected to be recognized over a weighted average period of 2.7 years.

During 2004, 337,360 stock option shares were exercised by employees exchanging 62,999 mature shares of stock with a fair value of $1.4 million. All of the mature shares exchanged were subsequently cancelled.

Restricted Stock Awards. The Company began issuing shares of restricted common stock to employees in 2004. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. The grant date fair value is amortized over the vesting period, ratably over four years from the date of grant for employees and the lesser of three years or remaining elected term at date of issuance for directors.

The following table provides a summary of the Company's restricted stock award activity for the year ended December 31, 2006:

	Restricted Shares	Weighted Average Grant-Date Fair Value
Non-vested restricted stock at December 31, 2005	38,430	$ 32.68
Granted	118,498	40.65
Vested	(19,602)	30.47
Forfeited	(5,596)	40.05
Non-vested restricted stock at December 31, 2006	**131,730**	**$ 39.87**

(in millions)	Year Ended December 31, **2006**	2005	2004
Total intrinsic value of restricted stock awards vested	**$ 0.8**	$ 0.2	$ -
Total intrinsic value of restricted stock awards outstanding	**5.7**	1.3	0.9

The intrinsic value above is based upon the closing market price of the Company's common stock on the last trading date of the year, $43.05.

The total compensation cost related to non-vested awards not yet recognized as of December 31, 2006, is $3.9 million. The cost is expected to be recognized over a weighted-average period of 3.2 years.

Conversion of Predecessor Shares

The Company has historically understated the number of shares issued and outstanding primarily as a result of improper conversion of predecessor company shares dating back to 1969. The impact of this adjustment on the balance sheet was less than $1 thousand, and the impact of the exclusion of these shares as outstanding was not material to the Company's reported earnings per share. The Company has adjusted the amount of shares and the balance in common stock in the accompanying consolidated statement of shareholders' equity as of January 1, 2006.

Treasury Share Purchases

In March 2004, the Compensation Committee of the Company's Board of Directors ("Board") approved the purchase of 48,650 shares of common stock from one of the Company's officers. The purchase price of the common stock was the closing price on the date of the purchase of $26.61 per share and totaled $1.3 million, which approximated the tax savings to be realized by the Company as a result of the exercise of said officer's non-qualified stock options in 2004. The Company also purchased 1,703 shares from an employee upon retirement from the Company in June 2004. All shares purchased were subsequently retired.

In March 2005, the Company publicly announced the authorization by its Board to purchase up to 2% of the Company's outstanding common stock (331,796 shares) at fair market value at the date of purchase. In June 2005, the Board approved an amendment of the size of the stock purchase from 2% to 10% (1,658,980 shares) of the Company's then outstanding common stock. Under the program, the Board had discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. The Company purchased pursuant to the plan 331,796 common shares at a cost of $7.9 million ($23.75 average price paid per share). This program expired on December 31, 2005. All shares purchased in accordance with the program have subsequently been retired.

In January 2006, the Company announced that its Board authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that management deemed appropriate. In October 2006, the Company completed its January 2006 program. Total shares purchased pursuant to the program were 1,627,500 common shares at a cost of $66.3 million ($40.75 average price paid per share), including 100,000 shares from an executive officer of the Company at a cost of $4.1 million ($40.66 price paid per share). All shares purchased in accordance with the program have subsequently been retired.

On October 16, 2006, the Board of Directors of the Company approved a second 2006 purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time.

Stock Repurchase Agreement

In May 2004, the Company repurchased 50,487 shares of common stock from the estate of one of the Company's former officer in accordance with the terms of a stock repurchase agreement. The repurchase totaled $1.4 million of which $1 million was funded by life insurance proceeds. Similar agreements with all other executive officers were terminated in December 2005.

NOTE 9 - EMPLOYEE BENEFIT PLANS

The Company sponsors a qualified deferred compensation plan covering substantially all of its employees. The plan consists of a 401(k) retirement plan with a profit sharing component. The plan enables eligible employees to contribute a portion of their compensation through payroll deductions in accordance with specific guidelines. The Company provides a discretionary matching contribution based on a percentage of the employees' contributions up to certain limits. The Company's contribution to the profit sharing component is discretionary. Total Company contributions, to both 401(k) and profit sharing, in 2006, 2005 and 2004, were $3.1 million, $0.9 million and $0.7 million, respectively.

The Company provides a supplemental retirement benefit of deferred compensation under terms of the various employment agreements with certain executive officers. During 2006, 2005 and 2004, the Company charged $0.3 million, $0.2 million and $0.2 million related to this plan to general and administrative expenses, respectively, and has recorded a related liability in the amount $1.9 million and $1.1 million as of December 31, 2006 and 2005, respectively.

In addition to the supplemental retirement benefit of deferred compensation, the Company offers a supplemental healthcare benefit covering certain executive officers and their spouses in accordance with each officer's employment agreement. During 2006, the Company charged $0.1 million related to this plan to general and administrative expenses and has a related liability in the amount of $0.6 million as of December 31, 2006.

The Company maintains a non-qualified deferred compensation plan for non-employee directors of the Company. The amount of compensation deferred by each participant is based on participant elections. The amounts deferred pursuant to the plan are invested in the Company's common stock, maintained in a rabbi trust and are classified in the accompanying balance sheet as treasury shares as a component of shareholders' equity. The plan may be settled in either cash or shares as requested by the participant. As of December 31, 2006, the Company had recorded a long-term liability of $0.2 million, which is included in other liabilities in the accompanying consolidated balance sheet.

NOTE 10 - EARNINGS PER SHARE

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the years ended December 31, (in thousands, except per share amounts):

	2006	2005	2004
Weighted average common shares outstanding	**15,660**	16,362	16,239
Dilutive effect of share-based compensation:			
Unamortized portion of restricted stock	**22**	13	1
Stock options	**55**	52	366
Non employee director deferred compensation	**4**	-	-
Weighted average common and common equivalent shares outstanding	**15,741**	16,427	16,606
Net income	**$ 237,772**	$ 41,452	$ 33,228
Basic earnings per common share	**$ 15.18**	$ 2.53	$ 2.05
Diluted earnings per common share	**$ 15.11**	$ 2.52	$ 2.00

Options with an exercise price exceeding the average price of the underlying securities are not considered to be dilutive, or anti-dilutive, and are included in the calculation of the denominator for diluted earnings per share. Common share equivalents attributable to anti-dilutive options, and therefore not included in the computation of earnings per share, for the years ended December 31, 2006, 2005 and 2004, were 23,687, 16,880 and 16,880, respectively.

NOTE 11 - TRANSACTIONS WITH AFFILIATES

Funds held for future distribution on the consolidated balance sheets was relatively unchanged at $31.4 million for each of the years ended December 31, 2006 and 2005. These funds primarily represent amounts owed to affiliated partnerships for undistributed production proceeds as of December 31, 2006 and 2005, respectively.

The Company provided oil and gas well drilling services and well operations and pipeline services to affiliated partnerships. Substantially all of the Company's revenue and expenses related to oil and gas well drilling operations and revenues from well operations and pipeline income are associated with services provided to the investing partners. Amounts due from/to the affiliated partnership are principally amounts related to derivative positions.

Management fees collected from the affiliated partnerships amounted to $1.3 million, $1.7 million and $1.5 million for the years ended December 31, 2006, 2005 and 2004, respectively, and are included in other income on the accompanying consolidated statements of income.

Revenues from oil and gas well drilling operations and costs of oil and gas well drilling operations each include $0.1 million, $0.2 million and $0.1 million during 2006, 2005 and 2004, respectively, related to investments made by officers of the Company for working interests in wells drilled during the respective years.

The Company through its wholly-owned subsidiary, PDC Securities Incorporated, acts as Dealer-Manager of the drilling partnerships. PDC Securities receives the applicable commissions and marketing allowances from the Escrow Agent of the drilling program and distributes them to the soliciting broker/dealers who sell the programs. The commissions and marketing allowances received by PDC Securities are included in other income net of the commissions distributed to the soliciting broker/dealer. The commissions and marketing allowances received by PDC Securities and distributed to the Soliciting Broker/Dealers amounted to $8.8 million, $11.4 million and $9.7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

During 2006, 2005 and 2004, the Company paid $18,000, $25,900 and $22,500, respectively, to the Corporate Secretary's law firm for various legal services.

NOTE 12 - COMMITMENTS AND CONTINGENCIES

The Company would be exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's derivative instruments or the counterparties to the Company's gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2006, 2005 or 2004.

The Company is a party to an exploration agreement with an unaffiliated party. The agreement requires the Company to drill a minimum of 25 wells through June 30, 2007. For each well the Company fails to drill prior to June 30, 2007, the Company will be required to pay liquidated damages equal to $125,000 per un-drilled well, for a maximum contingency of $3.1 million. Drilling pursuant to the agreement commenced in February 2007.

In connection with the Company's sale of undeveloped leaseholds in July 2006, the Company is obligated to either drill 16 wells on specifically identified acreage over the next three years (five by December 31, 2007, another five by December 31, 2008, and another six by December 31, 2009) or pay liquidated damages of $1.6 million per un-drilled well for a total contingent obligation of $25.6 million, of which $8 million is reflected in current liabilities, and $17.6 million is reflected as a deferred gain on sale of leaseholds, a long-term liability, in the consolidated balance sheets. See Note 15 for additional disclosure related to the sale.

Substantially all of the Company's drilling programs contain a repurchase provision where investing partners may request that the Company purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to the Company's financial ability to do so. The maximum annual repurchase obligation as of December 31, 2006, was approximately $12.3 million. The Company has adequate liquidity to meet this obligation. During 2006 and 2005, the Company paid $0.8 million and $0.4 million, respectively, under this provision for the repurchase of partnership units. As of December 31, 2006, outstanding repurchase offers to investing partners totaled $0.2 million, which $0.1 million of the outstanding offers was consummated in 2007 prior to expiration.

The Company's drilling programs formed from 1996 through the second quarter of 2005 contain a performance supplement that provides for changes in the distribution of partnership profits if certain levels of performance are not met. The terms of this provision in the partnership agreements are not a guarantee of a rate of return on an investment in the partnership. Under those specific conditions, such changes can result in the Company's share of an affected partnership's profits being reduced by up to one half of the amount to which it otherwise would be entitled in the affected period. In no event would the Company be obligated to assume a disproportionate share of losses in such partnerships; should the partnerships which contain this provision in the partnership agreements incur a loss, the Company's share of such losses would be unaffected by the terms of this provision. In accordance with these provisions, the Company's share of partnership profits was reduced by an aggregate of $1 million, $0.7 million and $0.6 million during 2006, 2005 and 2004, respectively. As of December 31, 2006 and 2005, based on production through December 31 of the corresponding year, the Company had accrued $0.4 million and zero, respectively.

As Managing General Partner of 76 partnerships the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. In January 2007, the Company purchased the remaining working interests in 44 of the 76 partnerships, which were sponsored by the Company in the late 1980s and 1990s (see Note 16). The Company's management believes the casualty insurance coverage carried by the Company and its subcontractors is adequate to meet this potential liability.

In order to secure the services for drilling rigs, the Company made commitments to the drilling contractors, which call for a minimum commitment of $9,000 daily for a specified amount of time if the Company ceases to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $34,400 daily for a specified amount of time for daily use of the drilling rigs. As of December 31, 2006, commitments for these two separate contracts expire in July 2009 and May 2010. As of December 31, 2006, the Company has an outstanding minimum commitment for $9.4 million and an outstanding maximum commitment for $36.1 million.

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

Recent litigation has commenced against several companies in our industry regarding royalty practices and payments in jurisdictions where the Company conducts business. While the Company's business model differs from those of the litigants in those cases, and the Company has not been named in any litigation, has not had similar litigation commenced, nor has such litigation been threatened, there can be no assurance that the Company will not be a party to any litigation or to similar litigation in the future.

NOTE 13 - LEASE OBLIGATIONS

The Company has entered into operating leases on behalf of itself and its affiliated partnerships principally for the leasing of natural gas compressors on its Michigan operating facilities. Additionally, the Company has operating leases for general office equipment. The future minimum lease payments under these non-cancelable operating leases as of December 31, 2006, are as follows: (in thousands)

Year	Lease Amount
2007	$ 502
2008	493
2009	495
2010	347
2011	208
Thereafter	4
	$ 2,049

The Company's share of this lease expense for operating leases for the years ended December 31, 2006, 2005 and 2004 was $0.4 million, $0.3 million and $0.3 million, respectively.

NOTE 14 – DERIVATIVE FINANCIAL INSTRUMENTS

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

The net fair value of the commodity based derivatives was $13.6 million of which $1.1 million is included in other long term assets at December 31, 2006. At December 31, 2005, the net fair value of commodity based derivatives was $(9.4) million of which $(1.4) million is included in other long term liabilities. The Company recognized in the statement of income an unrealized gain on commodity based derivatives of $7.6 million for the year ended December 31, 2006, and unrealized losses of $3.2 million and $1.1 million for the years ended December 31, 2005, and 2004, respectively.

The following tables summarize the open derivative option and purchase and sales contracts for Riley Natural Gas and the Company as of December 31, 2006 and 2005.

Riley Natural Gas
Open Derivative Positions
(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Futures/Swaps Purchases	246,900	$ 7.34	$ 1,811	$ (304)
Natural Gas	Cash Settled Futures/Swaps Sales	1,952,150	8.42	16,444	2,815
Natural Gas	Cash Settled Basis Swap Purchases	90,000	0.42	38	(12)
Natural Gas	Cash Settled Basis Swap Sales	20,000	0.50	10	4
Natural Gas	Cash Settled Option Purchases	220,000	5.50	1,210	64
Natural Gas	Cash Settled Option Sales	110,000	10.10	1,111	(39)
Natural Gas	Physical Purchases	1,964,150	8.27	16,244	(1,974)
Natural Gas	Physical Sales	114,974	9.62	1,106	310
Natural Gas	Physical Basis Purchases	20,000	0.45	9	(3)
Natural Gas	Physical Basis Sales	90,000	0.44	39	14
Positions maturing in 12 months following December 31, 2006					
Natural Gas	Cash Settled Futures/Swaps Purchases	246,900	$ 7.34	$ 1,811	$ (304)
Natural Gas	Cash Settled Futures/Swaps Sales	1,637,150	8.37	13,697	2,637
Natural Gas	Cash Settled Basis Swap Purchases	90,000	0.42	38	(12)
Natural Gas	Cash Settled Basis Swap Sales	20,000	0.50	10	4
Natural Gas	Cash Settled Option Purchases	220,000	5.50	1,210	64
Natural Gas	Cash Settled Option Sales	110,000	10.10	1,111	(39)
Natural Gas	Physical Purchases	1,649,150	8.27	13,641	(2,027)
Natural Gas	Physical Sales	114,974	9.62	1,105	310
Natural Gas	Physical Basis Purchases	20,000	0.45	9	(3)
Natural Gas	Physical Basis Sales	90,000	0.44	39	14
Prior Year Total Positions as of December 31, 2005					
Natural Gas	Cash Settled Futures/Swaps Purchases	1,025,500	$ 9.05	$ 9,283	$ 1,983
Natural Gas	Cash Settled Futures/Swaps Sales	3,149,000	7.95	25,018	(8,689)
Natural Gas	Cash Settled Basis Swap Purchases	450,000	0.91	409	(158)
Natural Gas	Cash Settled Basis Swap Sales	240,000	0.50	120	4
Natural Gas	Physical Purchases	2,819,000	8.32	23,456	7,858
Natural Gas	Physical Sales	585,222	10.72	6,272	(670)
Natural Gas	Physical Basis Purchases	240,000	0.45	108	8
Natural Gas	Physical Basis Sales	450,000	0.94	420	169

The maximum term for the derivative contracts listed above is 25 months.

Petroleum Development Corporation
Open Derivative Positions
(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Option Sales	17,390,000	$ 5.56	$ 96,613	$ 12,597
Natural Gas	Cash Settled Option Purchases	2,155,000	10.34	22,287	(14)
Oil	Cash Settled Option Purchases	300,000	50.00	15,000	155
Positions maturing in 12 months following December 31, 2006					
Natural Gas	Cash Settled Option Sales	15,530,000	$ 5.53	$ 85,850	$ 11,682
Natural Gas	Cash Settled Option Purchases	2,155,000	10.34	22,287	(14)
Oil	Cash Settled Option Purchases	300,000	50.00	15,000	155
Prior Year Total Positions as of December 31, 2005					
Natural Gas	Cash Settled Option Sales	5,665,000	$ 8.17	$ 46,273	$ (12,531)
Natural Gas	Cash Settled Option Purchases	14,030,000	6.36	89,210	2,660

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

In addition to including the gross assets and liabilities related to the Company's share of oil and gas production, the above tables and the accompanying consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate partnerships as the Managing General Partner. The accompanying consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of $7.5 million as of December 31, 2006 and a net receivable from the partnerships of $5.4 million as of December 31, 2005. In addition to the short-term fair value of derivatives shown in the accompanying consolidated balance sheet there are long-term assets and long-term liabilities which total to a net long-term asset of approximately $0.9 million and $1.3 million as of December 31, 2006 and 2005, respectively, related to the fair value of derivatives included in the accompanying consolidated balance sheets.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2006 and 2005, restricted cash in the amount of $0.5 million and $1.5 million was on deposit.

An interest rate swap agreement was used to reduce the potential impact of increases in interest rates on variable rate long-term debt. The swap agreement expired in October 2004. The agreement required the Company, on a quarterly basis, to make a fixed-rate interest payment of 6.89% plus its current LIBOR rate margin (+1.50% at December 31, 2003) on a $10 million amount related to its outstanding line of credit. The change in the fair value of the swap was included as a component of interest expense; the related gain was $0.6 million for the year ended December 31, 2004.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults during the years ended December 31, 2006, 2005 and 2004.

The following changes in the fair value of commodity based derivatives are reflected in the consolidated statements of income (in millions):

	Realized gains/(losses)			Unrealized gains/(losses)		
Statement of Income Line Item	**2006**	2005	2004	**2006**	2005	2004
Oil and gas price risk management gain (loss), net	$ 1.9	$ (6.4)	$ (1.6)	$ 7.2	$ (3.0)	$ (1.5)
Gas sales from marketing activities	2.6	(5.6)	0.8	12.3	(8.5)	1.2
Cost of gas marketing activities	(1.9)	(1.3)	(3.3)	(11.9)	8.3	(0.8)

Oil and gas price risk management gain (loss), net includes realized and unrealized gains and losses on commodity based derivatives related to the Company's oil and gas sales. Gas sales from marketing activities and cost of gas marketing activities includes realized and unrealized gains and losses on commodity based derivatives related to the RNG gas sales and gas purchases, respectively.

NOTE 15 - SALE OF OIL AND GAS PROPERTIES

Grand Valley Field Acreage

In July 2006, the Company sold to an unaffiliated company a portion of its undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. The sale encompassed 100% of the working interest in approximately 8,700 acres, including approximately 6,400 acres of the Company's Chevron leasehold and 2,300 acres of the Company's Puckett Land Company leasehold. The Company retained approximately 475 undeveloped locations on 10 acre spacing on the Grand Valley Field leasehold in addition to all of its producing properties in the field. The proceeds from the sale were $353.6 million.

The Company recorded a gain on sale of leaseholds of $328 million and a deferred gain on sale of leaseholds of $25.6 million. The Company is obligated to either drill 16 wells on specifically identified acreage over the next three years (five by December 31, 2007, another five by December 31, 2008, and another six by December 31, 2009) or pay liquidated damages of $1.6 million per un-drilled well. The Company expects to drill the wells for its own benefit and, as such, will record the costs of the wells drilled in accordance with its oil and gas properties accounting policy. For each well the Company drills, the Company will recognize $1.6 million of the deferred gain when drilling is complete. Alternatively, should the Company not first drill the wells, the unaffiliated company has the option to drill the wells for its benefit and, should it decide to exercise its option, with each well drilled, the Company would recognize both $1.6 million of the amount deferred and $0.4 million to be paid to the Company by the unaffiliated company. At December 31, 2006, $8 million of the deferred gain on sale of leaseholds is classified as short-term and included in other current liabilities in the accompanying consolidated balance sheet.

In conjunction with the sale, the Company entered into a LKE agreement, in accordance with IRC Section 1031, with a "qualified intermediary." Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. The Company had until mid-January 2007 to close any acquisition of suitable like-kind property, allowing the Company to take advantage of the income tax deferral benefits of a LKE transaction. See Note 16 for a further discussion of the acquisition of suitable like-kind properties.

During 2005, the Company sold a portion of one of its undeveloped Grand Valley Field, Garfield County, Colorado leases to an unaffiliated entity. The proceeds of the sale were $6.2 million and the Company's carrying value of the property was zero. The Company was required to remit $1 million to the original lessor, unless it commenced construction of certain facilities adjacent to this undeveloped property subject to certain timing conditions. The Company commenced construction of the facilities in 2005. The gain of $6.2 million was recognized in 2005 and is included in gain on sale of leaseholds in the accompanying consolidated statement of income.

Others

Additionally, in 2005, the Company completed the sale to an unaffiliated entity of 111 Pennsylvania wells it purchased in 1998. The Company received proceeds of $3.4 million and recorded a gain of $1.5 million, which is included in gain on sale of leaseholds in the accompanying consolidated statement of income.

NOTE 16 – SUBSEQUENT EVENTS

Acquisition of IRC Section 1031 – Like-Kind Exchange Properties

In January 2007, the Company completed its acquisitions of suitable like-kind properties in accordance with the LKE agreement it entered into in connection with its sale of undeveloped leaseholds located in Grand Valley Field, Garfield Country, Colorado in July 2006. The Company acquired for cash qualifying oil and gas properties totaling $191.5 million as described below.

EXCO Resources Inc. On January 5, 2007, the Company completed its purchase of EXCO Resources Inc.'s producing properties and remaining undeveloped drilling locations and acreage in the Wattenberg Field area of the DJ Basin, Colorado. The cash consideration paid for the EXCO properties was $130.9 million. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 oil and gas wells (approximating 25.5 Bcfe, net of royalty interests, proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. The Company will operate the assets and holds a majority working interest in the properties.

Company-Sponsored Partnerships. On January 10, 2007, the Company completed the purchase of the remaining working interests in 44 Company-sponsored partnerships for $58.8 million. The transaction resulted in an increase in the Company's net interest in 718 wells that are currently operated by the Company. The wells are located primarily in the Appalachian Basin and Michigan.

Other. The Company acquired from unaffiliated parties undeveloped leaseholds in Erath County, Texas for $1.8 million.

Other Acquisitions

On February 22, 2007, the Company acquired, from an unaffiliated party 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $11.8 million. The acquisition encompasses current daily production of approximately 668 Mcfe (520 Mcf of gas and 25 barrels of oil per day), net to the interests acquired, 100 or more undeveloped drilling locations, 19.1 Bcfe of proved reserves, and an additional 7.5 Bcfe of probable reserves.

NOTE 17 - BUSINESS SEGMENTS

The Company's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations and pipeline income. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 3,100 wells from which it sells its oil and gas production from its working interests in the wells. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the years ended December 31, 2006, 2005 and 2004 is presented below (in thousands).

Year Ended December 31,	2006	2005	2004
REVENUES			
Drilling and development	**$ 17,917**	$ 99,963	$ 94,076
Natural gas marketing	**131,326**	121,114	94,628
Oil and gas sales (1)	**124,336**	93,191	66,407
Well operations and pipeline income	**10,704**	8,760	7,677
Unallocated amounts	**2,220**	2,170	1,695
Total	**$ 286,503**	**$ 325,198**	**$ 264,483**
SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and development	**$ 5,300**	$ 11,778	$ 16,380
Natural gas marketing	**1,816**	1,737	1,784
Oil and gas sales (2)	**61,868**	46,095	35,090
Well operations and pipeline income (3)	**2,823**	3,539	3,695
Unallocated amounts			
General and administrative expense	**(19,047)**	(6,960)	(4,506)
Gain on sale of leaseholds	**328,000**	7,669	-
Interest income (4)	**7,407**	625	138
Interest expense	**(2,443)**	(217)	(238)
Other (5)	**1,685**	1,862	1,135
Total	**$ 387,409**	$ 66,128	$ 53,478
As of December 31,			
SEGMENT ASSETS			
Drilling and development	**$ 87,746**	$ 89,030	$ 64,348
Natural gas marketing	**39,899**	56,518	31,234
Oil & gas sales	**394,952**	251,897	205,680
Well operations and pipeline income	**28,895**	31,407	16,518
Unallocated amounts			
Cash	**109,467**	3,383	112
Designated cash - property acquisitions (6)	**191,512**	-	-
Other	**31,816**	12,126	11,561
Total	**$ 884,287**	$ 444,361	$ 329,453
EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS			
Drilling and development	**$ -**	$ -	$ -
Natural gas marketing	**-**	1	6
Oil & gas sales	**133,401**	92,907	45,713
Well operations and pipeline income	**1,419**	3,949	1,911
Unallocated amounts	**12,125**	2,452	1,302
Total	**$ 146,945**	$ 99,309	$ 48,932

(1) Includes oil and gas price risk management gains (losses), net.
(2) Includes $8.1 million and $11.1 million in exploration costs and $31.3 million and $19.3 million in DD&A for the years ended December 31, 2006 and 2005, respectively.
(3) Includes $1.9 million and $1.5 million in DD&A for the years ended December 31, 2006 and 2005, respectively.
(4) Includes interest income for PDC operations, $0.6 and $0.3 million in interest income allocated to Natural gas marketing for the years ended December 31, 2006 and 2005, respectively, in addition to partnership management fees.
(5) Includes $0.5 million and $0.3 million in DD&A for the years ended December 31, 2006 and 2005, respectively.
(6) Amount was expended in early 2007 in LKE transactions; the assets and liabilities of which will be included in the oil and gas sales segment.

NOTE 18 – SUPPLEMENTAL OIL AND GAS INFORMATION - UNAUDITED

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

Costs incurred by the Company in oil and gas property acquisition, exploration and development are presented below (in thousands).

	Year ended December 31,		
	2006	2005	2004
Acquisition of properties:			
Unproved properties	**$ 11,926**	$ 16,910	$ 4,583
Proved properties	**802**	1,608	720
Development costs	**114,487**	68,605	32,700
Exploration costs	**20,894**	12,943	4,170
Total costs incurred	**$ 148,109**	$ 100,066	$ 42,173

The proved reserves attributable to the development costs in the above table were 70,499 MMcf and 3,148 MBbls for 2006, 85,624 MMcf and 1,576 MBbls for 2005, 40,716 MMcf and 358 MBbls for 2004. Of the above development costs incurred for the years ended December 31, 2006, 2005 and 2004, the amounts of $1 million, $6.9 million and $1.8 million, respectively, were incurred to develop proved undeveloped properties from the prior year end.

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, recompletions and to provide facilities to extract, treat, gather and store oil and gas. Exploration costs include costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves.

Capitalized Oil and Gas Costs (Unaudited)

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

	December 31,	
	2006	2005
Proved oil and gas properties	**$ 473,451**	$ 334,301
Unproved oil and gas properties	**27,055**	19,846
	500,506	354,147
Less accumulated depreciation, depletion and amortization	**133,172**	102,513
	$ 367,334	$ 251,634

Suspended Well Costs (Unaudited)

The following table lists the capitalized exploratory well costs which are pending the determination of proved reserves (dollars in thousands).

	2006	2005	2004
Beginning balance at January 1	**$ 1,918**	$ 4,170	$ -
Additions to capitalized exploratory well costs pending the determination of proved reserves	**12,016**	6,441	4,170
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(13,169)**	(4,523)	-
Capitalized exploratory well costs charged to expense	**-**	(4,170)	-
Ending balance at December 31	**$ 765**	$ 1,918	$ 4,170

As of December 31, 2006, the one well awaiting the determination of proved reserves has not been capitalized for a period greater than one year.

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

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

	Years Ended December 31,		
	2006	2005	2004
Revenue:			
Oil and gas sales	**$ 115,189**	$ 102,559	$ 69,492
Oil and gas price risk management gain (loss), net	**9,147**	(9,368)	(3,085)
	124,336	93,191	66,407
Expenses:			
Production costs	**20,855**	16,194	14,201
Depreciation, depletion and amortization	**30,988**	19,322	16,680
Exploration costs	**8,131**	11,115	-
	59,974	46,631	30,881
Results of operations for oil and gas producing activities before provision for income taxes	**64,362**	46,560	35,526
Provision for income taxes	**24,818**	18,112	13,820
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	**$ 39,544**	$ 28,448	$ 21,706

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

Net Proved Oil and Gas Reserves (Unaudited)

The proved reserves of oil and gas of the Company have been estimated by independent petroleum engineers at December 31, 2006, 2005 and 2004. These reserves have been prepared in compliance with the SEC and FASB rules which require that reserve reports be prepared under economic and operating conditions existing at the Company's year-end with no provision for price and cost escalation except by contractual arrangements. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

	Oil (MBbls)		
	2006	2005	2004
Proved developed and undeveloped reserves:			
Beginning of year	**4,538**	3,316	3,029
Revisions of previous estimates	**35**	80	305
Beginning of year as revised	**4,573**	3,396	3,334
New discoveries and extensions			
Rocky Mountain region	**3,148**	1,576	358
Dispositions to partnerships	**(92)**	-	(12)
Purchases of reserves:			
Michigan	**-**	-	-
Rocky Mountain region	**274**	5	17
Appalachian	**-**	-	-
Production	**(631)**	(439)	(381)
End of year	**7,272**	4,538	3,316
Proved developed reserves:			
Beginning of year	**3,860**	3,190	2,889
End of year	**4,629**	3,860	3,190

	Natural Gas (MMcf)		
	2006	2005	2004
Proved developed and undeveloped reserves:			
Beginning of year	**247,288**	197,549	180,998
Revisions of previous estimates	**(28,067)**	(15,850)	(10,635)
Beginning of year as revised	**219,221**	181,699	170,363
New discoveries and extensions			
Rocky Mountain region	**70,499**	85,624	40,716
Dispositions to partnerships	**(1,215)**	(9,556)	(4,240)
Purchases of reserves:			
Michigan Basin	**35**	47	96
Rocky Mountain region	**3,477**	71	242
Appalachian basin	**222**	434	744
Production	**(13,161)**	(11,031)	(10,372)
End of year	**279,078**	247,288	197,549
Proved developed reserves:			
Beginning of year	**155,354**	146,152	134,936
End of year	**158,978**	155,354	146,152

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

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

	2006	2005	2004
Future estimated cash flows	**$ 1,804,796**	$ 2,381,238	$ 1,298,394
Future estimated production costs	**(571,346)**	(545,683)	(319,065)
Future estimated development costs	**(373,460)**	(207,164)	(95,498)
Future estimated income tax expense	**(334,536)**	(633,444)	(343,810)
Future net cash flows	**525,454**	994,947	540,021
10% annual discount for estimated timing of cash flows	**(309,792)**	(589,517)	(310,593)
Standardized measure of discounted future estimated net cash flows	**$ 215,662**	$ 405,430	$ 229,428

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows (in thousands).

	2006	2005	2004
Sales of oil and gas production net of production costs	**$ (94,337)**	$ (86,366)	$ (55,291)
Net changes in prices and production costs	**(299,721)**	208,353	26,768
Extensions, discoveries, and improved recovery, less related costs	**46,109**	150,654	51,413
Sales of reserves	**(3,356)**	(14,456)	(7,565)
Purchase of reserves	**11,003**	1,266	1,953
Development costs incurred during the period	**20,051**	24,035	8,495
Revisions of previous quantity estimates	**(23,146)**	(24,130)	6,312
Changes in estimated income taxes	**120,818**	(112,054)	(16,160)
Accretion of discount	**62,838**	38,241	33,500
Timing and other	**(30,027)**	(9,541)	(22,380)
Total	**$ (189,768)**	$ 176,002	$ 27,045

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

The estimated present value of future cash flows relating to proved reserves is extremely sensitive to prices used at any measurement period. The average prices used for each commodity for the years ended December 31, 2006, 2005 and 2004 are presented below.

	Average Price	
As of December 31:	Oil	Gas
2006	**$ 57.70**	**$ 4.96**
2005	$ 58.25	$ 8.56
2004	$ 41.63	$ 5.87

NOTE 19 - QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly financial data for the years ended December 31, 2006 and 2005, are presented below The sum of the quarters may not equal the total of the year's net income per share due to changes in the weighted average shares outstanding throughout the year (in thousands, except per share data).

	2006							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	Total
	As Reported (1)	As Revised (2)	As Reported (1)	As Revised (2)	As Reported (1)	As Revised (2)		
Revenues:								
Oil and gas well drilling operations	$ 5,278	$ 5,278	$ 3,745	$ 3,745	$ 2,659	$ 2,659	$ 6,235	$ 17,917
Gas sales from marketing activities	41,942	41,942	29,129	29,129	30,374	30,374	29,880	131,325
Oil and gas sales	29,208	28,332	27,267	27,992	29,663	30,577	28,288	115,189
Well operations and pipeline income	2,290	2,290	2,486	2,486	2,530	2,536	3,392	10,704
Oil and gas price risk management gains, net	4,435	4,925	1,367	1,370	2,912	2,707	145	9,147
Other income	3	3	21	21	1,964	1,964	233	2,221
Total revenues	83,156	82,770	64,015	64,743	70,102	70,817	68,173	286,503
Costs and expenses:								
Cost of oil and gas well drilling operations	4,081	4,212	3,159	3,278	4,311	3,838	1,289	12,617
Cost of gas marketing activities	41,775	41,780	28,462	28,471	29,883	29,988	29,911	130,150
Oil and gas production and well operations costs	7,261	6,949	6,770	6,830	8,762	8,584	6,658	29,021
Exploration costs	1,163	1,208	1,657	1,898	1,749	2,180	2,845	8,131
General and administrative expense	3,981	3,719	4,667	5,102	4,759	5,357	4,869	19,047
Depreciation, depletion and amortization	6,616	6,587	7,617	7,605	8,322	8,300	11,243	33,735
Total costs and expenses	64,877	64,455	52,332	53,184	57,786	58,247	56,815	232,701
Gain on sale of leaseholds	-	-	-	-	328,000	328,000	-	328,000
Income from operations	18,279	18,315	11,683	11,559	340,316	340,570	11,358	381,802
Interest income	388	392	343	349	3,427	3,475	3,834	8,050
Interest expense	(73)	(352)	(125)	(436)	(34)	(366)	(1,289)	(2,443)
Income before income taxes	18,594	18,355	11,901	11,472	343,709	343,679	13,903	387,409
Income taxes	6,797	6,710	4,351	4,192	132,795	132,795	5,940	149,637
Net income	$ 11,797	$ 11,645	$ 7,550	$ 7,280	$ 210,914	$ 210,884	$ 7,963	$ 237,772
Basic earnings per common share	$ 0.73	$ 0.72	$ 0.47	$ 0.45	$ 13.39	$ 13.39	$ 0.54	$ 15.18
Diluted earnings per common share	$ 0.73	$ 0.72	$ 0.47	$ 0.45	$ 13.33	$ 13.33	$ 0.54	$ 15.11

(1) As previously reported in the corresponding Form 10-Q reclassified to conform to current year presentation. See Note 1 for detailed discussion of reclassifications which impact current year presentation. In addition, $0.3 million was reclassified from cost of oil and gas well drilling operations to general and administrative expense and $0.8 million was reclassified from oil and gas production and well operations cost to exploration costs in the third quarter of 2006.

(2) The revised quarterly data in the above table reflects the impact on the quarterly results previously reported in 2006 of the adjustments recorded pursuant to SEC SAB No. 108 as described in Note 1.

PETROLEUM DEVELOPMENT CORPORATION

	2005				
	Quarter				
	First	Second	Third	Fourth	Year
Revenues:					
Oil and gas well drilling operations	$ 25,366	$ 28,111	$ 32,267	$ 14,219	$ 99,963
Gas sales from marketing activities	17,522	25,917	14,970	62,695	121,104
Oil and gas sales	18,664	21,543	28,414	33,938	102,559
Well operations and pipeline income	1,927	2,068	2,291	2,474	8,760
Oil and gas price risk management (losses) gains, net	(3,659)	858	(9,922)	3,355	(9,368)
Other income	(243)	1,860	7	556	2,180
Total revenues	59,577	80,357	68,027	117,237	325,198
Costs and expenses:					
Cost of oil and gas well drilling operations	20,644	23,743	28,734	15,064	88,185
Cost of gas marketing activities	17,902	26,177	14,269	61,296	119,644
Oil and gas production costs and well operations costs	4,093	4,595	6,379	5,333	20,400
Exploration costs	-	4,864	136	6,115	11,115
General and administrative expense	1,617	1,266	1,646	2,431	6,960
Depreciation, depletion and amortization	4,857	4,845	5,120	6,294	21,116
Total costs and expenses	49,113	65,490	56,284	96,533	267,420
Gain on sale of leaseholds	6,216	1,453	-	-	7,669
Income from operations	16,680	16,320	11,743	20,704	65,447
Interest income	241	179	202	276	898
Interest expense	(33)	(29)	(26)	(129)	(217)
Income before income taxes	16,888	16,470	11,919	20,851	66,128
Income taxes	6,248	6,091	4,413	7,924	24,676
Net income	$ 10,640	$ 10,379	$ 7,506	$ 12,927	$ 41,452
Basic earnings per common share	$ 0.64	$ 0.63	$ 0.46	$ 0.80	$ 2.53
Diluted earnings per common share	$ 0.64	$ 0.63	$ 0.46	$ 0.79	$ 2.52

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
(in thousands)

Description	Beginning balance	Additions charged to cost and expenses	Deductions		Ending balance
Allowance for doubtful accounts deducted from accounts receivable in the balance sheet					
2006	**$ 409**	**$ 7**	**$ 1**		**$ 415**
2005	$ 409	$ -	$ -		$ 409
2004	$ 487	$ -	$ 78	(a)	$ 409

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

Exhibit 31.1

CERTIFICATION

I, Steven R. Williams, certify that:

1. I have reviewed this Annual Report on Form 10-K of Petroleum Development Corporation.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditor and the audit committee of the registrant's board of directors (or persons performing the equivalent functions);

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 22, 2007

/s/ Steven R. Williams

Steven R. Williams
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard W. McCullough, certify that:

1. I have reviewed this Annual Report on Form 10-K of Petroleum Development Corporation.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditor and the audit committee of the registrant's board of directors (or persons performing the equivalent functions);

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 22, 2007

/s/ Richard W. McCullough
Richard W. McCullough
Chief Financial Officer

Exhibit 32.1

CERTIFICATION

In connection with the Annual Report of Petroleum Development Corporation (the "Company") on Form 10-K for the period ended December 31, 2006, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned certify pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven R. Williams — May 22, 2007
Steven R. Williams, Chairman,
and Chief Executive Officer

/s/ Richard W. McCullough — May 22, 2007
Richard W. McCullough
Chief Financial Officer and Treasurer

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Petroleum Development Corporation and will be retained by Petroleum Development Corporation and furnished to the Securities and Exchange Commission or its staff upon request

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GLOSSARY OF TERMS USED IN THIS ANNUAL REPORT

Bbl	Barrel(s) of oil. One barrel of oil is equal to the energy equivalent of six Mcf of natural gas.
Bcf	Billion cubic feet of natural gas
Bcfe	Billion cubic feet of natural gas equivalent
CAPEX	Capital Expenditures
EBITDA	Earnings before interest expense, income taxes, depreciation, depletion and amortization. A cash flow financial measure commonly used in the oil and gas industry.
MBbl	Thousand barrels of oil
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent of natural gas
MMBbl	Million barrels of oil
MMBoe	Million barrels of oil equivalent
MMcf	Million cubic feet of natural gas
MMcfe	Million cubic feet equivalent of natural gas
SEC PV-10	The value of proved reserves based on year-end commodity prices, discounted at 10 percent.

STOCK EXCHANGE LISTING
The Company's common stock trades on The NASDAQ Global Select Stock Market, under the symbol "PETD."

CODE OF BUSINESS CONDUCT AND ETHICS
The Code of Business Conduct and Ethics of Petroleum Development Corporation is available on our website at www.petd.com, or a copy may be obtained by writing to the Company.

DIRECTORS AND OFFICERS

STEVEN R. WILLIAMS
Chairman of the Board of Directors and Chief Executive Officer

THOMAS E. RILEY
President and Director

ERIC R. STEARNS
Executive Vice President Exploration and Development

RICHARD W. MCCULLOUGH
Chief Financial Officer and Treasurer

DARWIN L. STUMP
Chief Accounting Officer

CELESTA M. MIRACLE
Vice President Investor Relations and Communications

TINA R. SMITH
Vice President Natural Gas and Oil Marketing

ERSEL E. MORGAN
Vice President Special Projects

DEWEY W. GERDOM
Vice President Exploration

BART BROOKMAN
Vice President Production

ANTHONY J. CRISAFIO
Director

VINCENT F. D'ANNUNZIO
Director

DAVID C. PARKE
Director

JEFFERY C. SWOVELAND
Director

KIMBERLY L. WAKIM
Director

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Certified Public Accountants
Pittsburgh, Pennsylvania

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Washington, District of Columbia

Young, Morgan & Cann
Clarksburg, West Virginia

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Houston, Texas

Wright & Company, Inc.
Nashville, Tennessee

TRANSFER AGENT
Transfer Online
317 SW Alder Street, 2nd Floor
Portland, Oregon 97204

Contact for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

FORM 10-K
A copy of the Company's Annual Report on Form 10-K for the year ended December 31, 2006 as filed with the Securities Exchange Commission may be obtained by writing to the Company.

PETROLEUM DEVELOPMENT CORPORATION
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