PETROLEUM DEVELOPMENT CORP
Form 10-K
March 04, 2010

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

or

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

For the transition period from __________ to _________

Commission File Number 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.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (303) 860-5800

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

Title of Each Class	Name of Each 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 þ

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	¨	Accelerated filer	þ
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2009, was $228,721,681 (based on the then closing price of $15.69).

As of February 16, 2010, there were 19,240,478 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form is incorporated by reference to our definitive proxy statement to be filed pursuant to Regulation 14A for our 2010 Annual Meeting of Shareholders.

PETROLEUM DEVELOPMENT CORPORATION
2009 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references to "PDC," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation, together with its wholly owned subsidiaries, entities in which it has a controlling financial interest and proportionate share of its sponsored drilling partnerships.

GLOSSARY OF NATURAL GAS AND OIL TERMS

Words defined in the Glossary of Natural Gas and Oil Terms are set in boldface type the first time they appear.

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One oil barrel or 42 gallons of liquid volume.
Bcf – One billion cubic feet of natural gas volume.
Bcfe – One billion cubic feet of natural gas equivalent.
Btu – British thermal unit.
MBbls – One thousand oil barrels.
Mcf – One thousand cubic feet of natural gas volume.
Mcfe – One thousand cubic feet of natural gas equivalent (six Mcf of natural gas equals one Bbl of oil).
Mmbtu – One million British thermal units.
Mmcf – One million cubic feet of natural gas volume.
Mmcfe – One million cubic feet of natural gas equivalent.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). Our SEC filings are available free of charge from the SEC's website at www.sec.gov or from our website at www.petd.com. You may also read or copy any document we file at the SEC's public reference room in Washington, D.C., located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the public reference room. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact Petroleum Development Corporation, Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call toll free 800-624-3821.

In addition to our SEC filings, our website can be used to access other information, including our recent news releases, bylaws, committee charters, code of business conduct and ethics, shareholder communication policy, director nomination procedures and our whistleblower hotline. However, the information available on our website is not part of this report and is not hereby incorporated by reference.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are forward-looking statements. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein, which include statements of estimated natural gas and oil production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management's strategies, plans and objectives. However, these are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of natural gas and oil, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements. 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 natural gas and oil;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability and cost of capital to us;
- risks incident to the drilling and operation of natural gas and oil wells;
- future production and development costs;

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- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America ("U.S.");
- the effect of natural gas and oil derivatives activities;
- conditions in the capital markets; and
- losses possible from pending or future litigation.

Further, we urge you to carefully review and consider the disclosures made in this report, including the risks and uncertainties that may affect our business as described herein under Item 1A, Risk Factors, and our other filings with the SEC. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events.

ITEM 1. BUSINESS

Overview

We are an independent energy company engaged in the exploration for and the acquisition, development, production and marketing of natural gas and oil. Since we began natural gas and oil operations in 1969, we have grown through drilling and development activities, acquisitions of producing natural gas and oil wells and the expansion of our natural gas marketing business.

During 2009, we managed our balance sheet in an effort to ensure that we had sufficient liquidity during an uncertain economic environment and we intend to maintain this spending discipline going forward. We focused our efforts on our ability to control spending by concentrating on cost reductions in lease operating expenses and per well capital expenditures and limiting our capital budget to be within our expected operating cash flows. Additionally, we raised capital through an equity offering and asset monetization through the formation of our Appalachian joint venture.

Based on unstable economic conditions existing early in 2009 and uncertainty as to when commodity and financial markets would recover to a perceived normal level, we reduced our planned 2009 capital expenditures to $108 million, or approximately 33% of our 2008 level. Additionally, we targeted our drilling dollars in the oil–rich section of the Wattenberg Field in our Rocky Mountain Region to take advantage of the pricing of oil over natural gas. Then, in August 2009, we completed an underwritten public offering of 4.3 million shares of the Company’s common stock at a price of $12.00 per share for net proceeds of $48.5 million. Finally, in October 2009, we entered into a joint venture arrangement with an unaffiliated party that monetized a portion of our Appalachian Basin assets. We entered into the joint venture with Lime Rock Partners ("Lime Rock") primarily to develop our Marcellus Shale acreage in the Appalachian Basin. At closing, we received a return of capital payment of $45 million. Upon the fulfillment of Lime Rock's commitment to provide future operational funding of $68.5 million, Lime Rock will earn a 50% interest in our Appalachian assets, exclusive of our interest in our affiliated partnerships’ wells. We do not expect to make any capital contributions to the joint venture in 2010 or until Lime Rock achieves a 50% interest, which is expected to occur in 2011.

Business Strategy

Our primary objective is to increase shareholder value through the growth of our reserves and production, while operating our properties in an efficient manner to maximize the cash flow and earnings potential of our assets.

Drill and Develop. Our acreage holdings include positions primarily in the Rocky Mountain Region and, through our joint venture, the Appalachian Basin. We believe that we will be able to continue to drill a substantial number of new wells on our current undeveloped properties. As of December 31, 2009, we had approximately 2,285 gross drill sites available in the Rocky Mountain Region and, through our joint venture, 569 gross drill sites available in the Appalachian Basin. In 2010, we plan to drill approximately 226 gross, 188.5 net, development wells in our Rocky Mountain Region and 26 gross wells, 15.6 net wells, targeted for the Marcellus Shale in the Appalachian Basin.

Rocky Mountain Region. Our primary focus in the Rocky Mountain Region is on developmental drilling in the Wattenberg Field and in Northeastern Colorado, or NECO, (both located in the DJ Basin) and the Grand Valley Field in the Piceance Basin. We seek to maximize the value of our existing wells through a program of well recompletions, refractures and workovers. In 2010, we plan to workover 50 wells and recomplete and/or refrac 12 wells.

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Appalachian Basin. Historically, our focus was on developmental drilling, targeting predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs. In 2009, our focus shifted to that of exploratory drilling, targeting the Marcellus Shale formation in West Virginia and Pennsylvania. In 2010, through our joint venture, our preliminary budget includes plans to drill 26 development wells targeting the Marcellus and 50 recompletes and 29 workovers targeting the shallow Devonian.

Strategically Acquire. Our acquisition efforts focus on producing properties that have a significant undeveloped acreage component. When weighing potential acquisitions, we prefer properties that have most of their value in producing wells, behind pipe reserves and high quality proved undeveloped locations. Historically, acquisitions have offered efficiency improvements through economies of scale in management and administration costs. During the period December 2006 through October 2007, we completed a series of asset and company acquisitions, three in our core operating area of the Rocky Mountain Region and two in the Appalachian Basin. While we had no significant acquisitions of properties in 2008 or 2009, we continue to identify and evaluate acquisition opportunities that will enhance our current properties and provide an opportunity to explore and develop new prospects.

Manage Risk. Historically, we have concentrated on development drilling and geographical diversification to reduce risk levels associated with natural gas and oil drilling, production and markets. Currently, a majority of our proved reserves are located in the Rocky Mountain Region. However, we benefit from operational diversity in the Rocky Mountain Region by maintaining significant activity and production in three separate areas, including the Wattenberg Field in north central Colorado and the NECO area, both located in the DJ Basin, and the Grand Valley Field in the Piceance Basin in western Colorado. Additionally, we regularly review opportunities to further diversify into other regions where we can apply our operational expertise. We believe development drilling will remain the foundation of our drilling activities in the future because it is less risky than exploratory drilling and is likely to generate cash returns more quickly. In addition to improving our liquidity position, the formation of the joint venture serves to mitigate the risks associated with exploring our Marcellus rights. We view exploratory activities as having the potential to identify new development opportunities at a cost competitive with the current cost of acquiring proven locations.

We maintain a conservative financial approach and proactively employ strategies to reduce the effects of commodity price volatility to help manage the risks associated with the oil and natural gas industry (the "industry"). We use natural gas and oil derivatives contracts primarily to reduce the effects of volatile commodity prices. At any given time, we have derivative contracts in place on a varying portion of our production; however, pursuant to our derivative policy, all volumes for derivatives contracts are limited to 80% of our future production from producing wells at the time we enter into the derivative contracts, with the exception of put contracts, or floors, for which volumes are not limited. As of December 31, 2009, we had natural gas and oil hedges in place covering 66.2% of our expected natural gas production and 59.8% of our expected oil production in 2010. Further, while our derivative instruments are utilized to manage the impact of price volatility of our natural gas and oil production, we have elected not to formally designate these instruments as hedging instruments and therefore, we do not use hedge accounting. Accordingly, we are required to recognize changes in the fair value of our derivative instruments in earnings each reporting period and, therefore, have the potential for significant earnings volatility. Our policy prohibits the use of natural gas and oil derivative instruments for speculative purposes. See Note 2, Summary of Significant Accounting Polices – Derivative Financial Instruments and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

Business Segments

We divide our operating activities into two segments: natural gas and oil sales and natural gas marketing. See Note 14, Business Segments, to our consolidated financial statements included in this report.

Natural Gas and Oil Sales. Our natural gas and oil sales segment primarily reflects revenues and expenses from the production and sale of natural gas and oil. During 2009, natural gas and oil represented 82.1% and 17.9% of our total production volumes, respectively, with 87% of our total production being generated by our Rocky Mountain Region properties and 9.4% by our Appalachian Basin properties. The majority of our undeveloped acreage is in our Rocky Mountain Region, where our 2009 drilling activities were focused and will continue to be the focus in 2010.

We operate approximately 92.7% of the wells in which we own a working interest. With respect to wells we operate and own an interest of less than 100%, we charge the other working interest owners, including our drilling partnerships, a competitive fee for operating the well and transporting natural gas. Revenues and expenses related to our well operations and transportation of natural gas are included in our natural gas and oil sales segment.

Natural Gas Marketing. Our natural gas marketing segment is comprised of our wholly-owned subsidiary Riley Natural Gas ("RNG"), through which we purchase, aggregate and resell natural gas produced by us and others. This allows us to diversify our operations beyond natural gas drilling and production. Through RNG, we have established relationships with many of the natural gas producers in the Appalachian Basin and have gained significant expertise in the natural gas end-user market.

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Areas of Operations

The following map presents the general locations of our exploration, development and production activities as of December 31, 2009.

We focus our exploration, development and production efforts primarily in two geographic areas: the Rocky Mountain Region and the Appalachian Basin. The majority of our undeveloped acreage is in the Rocky Mountain Region and our current drilling plans continue to be focused predominantly in this area.

Rocky Mountain Region. Our Rocky Mountain Region is divided into three major operating areas: (1) Grand Valley Field, (2) Wattenberg Field and (3) NECO area. Our Rocky Mountain Region includes approximately 293,600 gross acres of leasehold and 2,524 gross, 1,654.3 net, natural gas and oil wells in which we own an interest.

- Grand Valley Field, Piceance Basin, Garfield County, Colorado. Development wells drilled in the area range from 7,000 to 9,500 feet in depth and the majority of wells are drilled directionally from multi-well pads generally ranging from two to ten wells per drilling pad. The primary target in the area is gas reserves, developed from multiple sandstone reservoirs in the Mesaverde Williams Fork formation. Well spacing is approximately ten acres per well.

- Wattenberg Field, DJ Basin, Weld County, Colorado. Wells drilled in the area range from approximately 7,000 to 8,000 feet in depth and generally target natural gas and oil reserves in the Niobrara, Codell and J Sand reservoirs. Well spacing ranges from 20 to 40 acres per well. Operations in the area, in addition to the drilling of new development wells, include the refrac of Codell and Niobrara reservoirs in existing wellbores whereby the Codell sandstone reservoir is fraced a second time and/or initial completion attempts are made in the slightly shallower Niobrara carbonate reservoir. Unlike our other two Rocky Mountain areas, the Wattenberg Field produces a significant amount of oil and, to a lesser extent, natural gas liquids.

- NECO area, DJ Basin, Yuma County, Colorado and Cheyenne County, Kansas. Wells drilled in the area range from approximately 1,500 to 3,000 feet in depth and target gas reserves in the shallow Niobrara reservoir. Well spacing is approximately 40 acres per well. Drilling operations range from exploratory wells to test undrilled, seismically defined, structural features at the Niobrara horizon to development wells targeting known reserves in existing identified features.

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- Other Rocky Mountain Region Areas. We currently own an interest in 14 gross, 5 net, natural gas and oil wells in Burke County, North Dakota and 3 gross, 0.7 net, oil wells in Wyoming. As of December 31, 2009, our remaining North Dakota leasehold encompasses approximately 58,400 gross acres with approximately 25,600 net undeveloped acres remaining for development and our Wyoming leasehold encompasses approximately 19,200 gross and net undeveloped acres. We currently have no drilling activity planned for these areas in 2010.

Appalachian Basin. We own an interest in approximately 271 gross, 88.5 net, natural gas and oil wells in West Virginia, Pennsylvania and Tennessee outside of our interest in our joint venture with Lime Rock. Additionally, in association with the joint venture, we own an interest in approximately 1,980 gross, 1,586.4 net, wells. Wells located in this area are approximately 4,500 feet deep and target predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs.

Other Areas. We own an interest in approximately 210 gross, 146.5 net, natural gas and oil wells in the Michigan Basin that produced 1.4 Bcfe net to our interest in 2009. As of December 31, 2009, our remaining Michigan leasehold encompasses 10,000 gross, 8,500 net, undeveloped acres. Wells in the area range from 1,000 to 2,500 feet in depth and produce gas from the Antrim Shale. We also hold a total of 27,200 gross, 21,500 net, undeveloped acres in New York and Texas. We currently have no drilling activity planned for these three areas in 2010.

The table below presents our productive wells by operating area at December 31, 2009.

	Productive Wells					
	Natural Gas		Oil		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region						
Wattenberg	1,459	944.7	25	19.2	1,484	963.9
Grand Valley	306	180.4	-	-	306	180.4
NECO	717	504.3	-	-	717	504.3
Other	5	1.3	12	4.4	17	5.7
Total Rocky Mountain Region	2,487	1,630.7	37	23.6	2,524	1,654.3
Appalachian Basin (1)	2,212	1,659.4	39	15.5	2,251	1,674.9
Other	208	148.8	7	2.7	215	151.5
Total productive wells	4,907	3,438.9	83	41.8	4,990	3,480.7

(1) Includes 100% of the wells owned by the joint venture.

Operations

Prospect Generation

Our staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. 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, we have collected and continue to collect logs, core data, production information and other raw data available from state and private agencies and 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, our land department obtains available natural gas and oil leaseholds, farm-outs and other development rights in these prospective areas. In most cases, to secure a lease, we pay a lease bonus and an annual rental payment, converting, upon initial production, to a royalty. In addition, overriding royalty payments may be granted to third parties in conjunction with the acquisition of drilling rights initially leased by others. See a summary of our acreage available for development below.

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Financing of Company Drilling and Development Activities

We have historically funded our drilling and development activities through our cash flows from operations, capital provided from our credit facility, sale of leaseholds, a senior notes issuance and, in August 2009, an equity offering. Further, in October 2009, we entered into a joint venture arrangement that monetized a portion of our Appalachian Basin assets in which we received $45 million as a return of capital and provides for future operational funding of $68.5 million in the same area. In addition to any combination of our historical sources, future sources of funding may include, but not limited to, volumetric production payments, debt securities and convertible debt securities.

Purchases of Producing Properties

In addition to drilling new wells, we continue to pursue opportunities to purchase existing wells and development rights from other owners, as well as greater ownership interests in the wells we operate. Generally, outside interests purchased include a majority interest in the wells and the right to operate the wells. In January 2007, we completed the purchase from an unrelated party of approximately 144 natural gas and oil wells and 8,160 acres of leaseholds in the Wattenberg Field. Also in January 2007, we purchased the outside partnership interests in 44 partnerships which we sponsored and 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, we acquired from an unrelated party 28 producing wells and associated undeveloped acreage in Colorado. In October 2007, we purchased from unrelated parties a majority working interest of 762 natural gas wells located in southwestern Pennsylvania. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage. No significant acquisitions were made in 2008 or 2009.

Title to Properties

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the industry. As is customary in the industry, a preliminary title examination is conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial work is performed with respect to discovered defects which we deem to be significant. Title examinations have been performed with respect to substantially all of our producing properties.

The properties we own are subject to royalty, overriding royalty and other outstanding interests customary to the industry. The properties may also be subject to additional burdens, liens or encumbrances customary to the industry, including items such as operating agreements, current taxes, development obligations under natural gas and oil leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with the use of the properties.

Acreage

The following table presents, by operating area, leased acres as of December 31, 2009.

	Developed		Undeveloped		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region						
Wattenberg	48,400	45,500	23,800	19,400	72,200	64,900
Grand Valley	2,700	2,700	5,300	5,300	8,000	8,000
NECO	23,600	19,600	103,500	85,500	127,100	105,100

Other	8,700	4,700	77,600	44,800	86,300	49,500
Total Rocky Mountain Region	83,400	72,500	210,200	155,000	293,600	227,500
Appalachian Basin (1)	109,600	106,800	11,300	10,800	120,900	117,600
Other	17,200	15,200	37,200	30,000	54,400	45,200
Total acreage	210,200	194,500	258,700	195,800	468,900	390,300

(1)Includes 100% of the acreage related to the joint venture.

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Drilling Activities

The following table presents our development and exploratory drilling activity for the last three years. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of producing wells and wells capable of commercial production.

	Drilling Activity					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive (1)						
Rocky Mountain Region	87	68.2	289	243.8	316	247.9
Appalachian Basin	2	2.0	60	60.0	8	8.0
Other	-	-	-	-	3	3.0
Total productive	89	70.2	349	303.8	327	258.9
Dry						
Rocky Mountain Region	2	1.0	8	8.0	11	9.7
Appalachian Basin	-	-	-	-	-	-
Other	-	-	-	-	-	-
Total dry	2	1.0	8	8.0	11	9.7
Total development	91	71.2	357	311.8	338	268.6
Exploratory:						
Productive (1)						
Rocky Mountain Region	2	1.0	4	4.0	1	0.2
Appalachian Basin	5	5.0	-	-	-	-
Other	-	-	3	3.0	-	-
Total productive	7	6.0	7	7.0	1	0.2
Dry						
Rocky Mountain Region	-	-	7	7.0	7	4.5
Appalachian Basin	-	-	-	-	-	-
Other	-	-	3	2.6	-	-
Total dry	-	-	10	9.6	7	4.5
Pending determination	2	2.0	5	5.0	3	3.0
Total exploratory	9	8.0	22	21.6	11	7.7
Total drilling activity	100	79.2	379	333.4	349	276.3
Recompletions/refractures	32	30.6	125	106.9	181	155.3

(1) As of December 31, 2009, a total of 19 productive wells were waiting to be fractured and/or for gas pipeline connection, of which 10 were connected and turned in line by February 15, 2010.

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The following table presents the wells drilled, by operating area, during the last three years, as well as our planned 2010 drilling activity.

	Planned 2010	2009		2008		2007	
	Gross	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region							
Wattenberg	180	82	65.2	149	122.7	158	106.0
Grand Valley	21	1	1.0	62	54.4	53	41.7
NECO	25	8	4.5	98	88.2	123	115.0
Other	-	1	0.5	2	0.5	3	1.6
Total Rocky Mountain Region	226	92	71.2	311	265.8	337	264.3
Appalachian Basin (1)	26	8	8.0	62	62.0	8	8.0
Other	-	-	-	6	5.6	4	4.0
Total wells planned/drilled	252	100	79.2	379	333.4	349	276.3

(1)During 2009, 7 gross wells were drilled prior to the formation of the joint venture and 1 was drilled subsequent to its formation. The drilling activity planned for 2010 will be conducted for the benefit of the joint venture and funded by our joint venture partner.

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

Drilling and Development Activities Conducted for Company Sponsored Partnerships

We began sponsoring drilling partnerships in 1984, and had sponsored one or more every year through 2007. For many years, our drilling partners were primarily the public and private partnerships we sponsored. At closing, we contributed a cash investment to purchase an interest in the drilling and development activities of the partnership and then serve as the managing general partner. As wells produce for a number of years, we continue to serve as operator for 33 partnerships, as well as for other unaffiliated parties.

When developing wells for our partnerships or others, we entered into a development agreement with the investor partner, pursuant to which we agreed to sell some or all of our rights in a well to be drilled to the partnership or other entity. The partnership or other entity thereby became an owner of a working interest in the well. In our financial reporting, we report only our proportionate share of natural gas and oil reserves, production, natural gas and oil sales and costs associated with wells in which we have a noncontrolling financial interest.

In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008. We affirmed this position in 2009 to change our business model from a partnership sponsor to that of an independent exploration and production company. Under our previous model, we drilled both partnership wells and wells for our own account. In the case of the partnership wells, we effectively limited drilling and operating risk borne by us to generally 20% to 37% of the total cost of the drilling activity. Since we have discontinued the partnership sponsor model, our composite exposure to risks associated with drilling and operating natural gas and oil properties have increased because we drill and operate all natural gas and oil wells using our operating cash flows and debt.

Drilling and Development Activities Conducted for Appalachian Joint Venture

With the formation of our joint venture arrangement with Lime Rock, we are able to engage in extensive drilling activities in the Appalachian Basin using capital of $68.5 million committed by our joint venture partner. After our joint venture partner achieves a 50% interest in the joint venture, all future funding of capital will be shared equally. While sharing the risk inherent in exploratory drilling, we are still able to maintain a portion of the potential benefits associated with such risk.

In our financial reporting, as of and for the year ended December 31, 2009, we consolidated the natural gas and oil revenues, production, natural gas and oil sales and costs associated with the wells within the joint venture which we have a controlling financial interest.

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Natural Gas and Oil Reserves

All of our natural gas and oil reserves are located in the U.S. Our reserve estimates are prepared with respect to reserve categorization, using the definitions for proved reserves set forth in SEC Regulation S-X, Rule 4-10(a) and subsequent SEC staff regulations, interpretations and guidance. All of our proved natural gas and oil reserves, including reserves held by consolidated companies and our proportionate share of our affiliates partnerships, have been estimated by independent consultants.

We have a comprehensive process that governs the determination and reporting of our proved reserves. As part of our internal control process, our reserves are reviewed annually by an internal team composed of reservoir engineers, geologists and accounting personnel for adherence to SEC guidelines through a detailed review of land records, available geological and reservoir data as well as production performance data. The review includes, but is not limited to, confirmation that reserve estimates (1) include all properties owned; (2) are based on proper working and net revenue interests; and (3) reflect reasonable cost estimates and field performance. The internal team compiles the reviewed data and forwards the data to independent consulting firms engaged to estimate our reserves.

For each of the years in the three-year period ended December 31, 2009, our reserve estimates for the Rocky Mountain Region and Fort Worth Basin, approximately 89% of our total proved reserves, are based on reserve reports prepared by Ryder Scott Company, L.P. and for the Appalachian and Michigan Basins are based on reserve reports prepared by Wright & Company. When preparing our reserve estimates, the independent engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, natural gas and oil production, well test data, historical costs of operations and development, product prices, or any agreements relating to current and future operations of properties and sales of production.

The independent petroleum engineers prepare an estimate of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to assure that the reserve estimates are complete, determined by acceptable industry methods and to a level of detail we deem appropriate. The final independent petroleum engineers' estimated reserve reports are reviewed and approved by our engineering staff and management.

The professional qualifications of the lead engineer primarily responsible for overseeing the preparation of our reserve estimate meet the standards of Reserves Estimator as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers. This employee holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering and has over 25 years of experience in reservoir engineering. The individual is a member of the Society of Petroleum Engineers, allowing the individual to remain current with the developments and trends in the industry. Further, during 2009, this individual attended ten hours of formalized training relating to the definitions and disclosure guidelines set forth in the SEC's final rule released January 2009, Modernization of Oil and Gas Reporting.

The tables below present information regarding our estimated proved reserves. Reserves cannot be measured exactly, because reserve estimates involve judgments. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. Neither the present value of estimated future net cash flows nor the standardized measure is intended to represent the current market value of the estimated natural gas and oil reserves we own. For additional information regarding both of these measures, see the Natural Gas and Oil Operations section of the supplemental information provided with our consolidated financial statements included in this report.

	December 31,		
	2009	2008	2007
Proved reserves			

Natural gas (MMcf)	608,925	662,857	593,563
Oil (MBbl)	18,070	15,037	15,338
Total proved reserves (MMcfe)	717,345	753,079	685,591
Proved developed reserves (MMcfe)	295,839	329,669	317,884
Estimated future net cash flows (in thousands)(1)	$ 764,111	$ 1,056,890	$ 1,847,485
Standardized measure (in thousands) (1)(2)	$ 347,636	$ 356,805	$ 753,071

(1) Estimated future net cash flow represents the undiscounted estimated future gross revenue to be generated from the production of proved reserves, net of estimated production costs, future development costs and income tax expense.

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Prices used to estimate future gross revenues and production and development costs were based on the following:

- Gross revenues
- For 2009, a 12-month average price calculated as the unweighted arithmetic average of the price on the first day of each month, January through December.
- For 2007 and 2008, prices in effect as of December 31 for the respective year.
- Prices for each of the three years were adjusted by lease for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity hedges.
- Production and development costs
- Prices as of December 31 for each of the respective years presented.
- The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization expense.

(2) The standardized measure of discounted future net cash flow represents the present value of estimated future net cash flows discounted at a rate of 10% per annum to reflect timing of future cash flows.

	December 31, 2009				
	Natural Gas (MMcf)	Oil (MBbl)	Natural Gas Equivalent (MMcfe)	Percent	
Proved developed					
Rocky Mountain Region					
Wattenberg	55,233	5,675	89,283	30	%
Grand Valley	101,504	243	102,962	34	%
NECO	31,463	-	31,463	11	%
Other	361	251	1,867	1	%
Total Rocky Mountain Region	188,561	6,169	225,575	76	%
Appalachian Basin	55,008	34	55,212	19	%
Other	14,806	41	15,052	5	%
Total proved developed	258,375	6,244	295,839	100	%
Proved undeveloped					
Rocky Mountain Region					
Wattenberg	70,838	11,552	140,150	33	%
Grand Valley	273,875	274	275,519	66	%
Total Rocky Mountain Region	344,713	11,826	415,669	99	%
Appalachian	5,837	-	5,837	1	%
Total proved undeveloped	350,550	11,826	421,506	100	%
Proved reserves					
Rocky Mountain Region					
Wattenberg	126,071	17,227	229,433	32	%
Grand Valley (1)	375,379	517	378,481	53	%
NECO	31,463	-	31,463	4	%
Other	361	251	1,867	-	
Total Rocky Mountain Region	533,274	17,995	641,244	89	%
Appalachian	60,845	34	61,049	9	%
Other	14,806	41	15,052	2	%
Total proved reserves	608,925	18,070	717,345	100	%

(1)Two leases in our Grand Valley Field represent 53% of our total proved reserves.

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Production, Sales, Prices and Lifting Costs

The following table presents information regarding our production volumes, natural gas and oil sales, average sales price received and average lifting cost.

	Year Ended December 31,		
	2009	2008	2007
Production (1) (2)			
Natural gas (Mcf)	35,536,092	31,759,792	22,513,306
Oil (Bbls)	1,291,488	1,160,408	910,052
Natural gas equivalent (Mcfe)	43,285,020	38,722,240	27,973,618
Mcfe per day	118,589	106,088	76,640
Natural Gas and Oil Sales (in thousands)			
Natural gas	$110,735	$221,734	$119,991
Oil	71,064	104,168	55,196
Provision for underpayment of natural gas sales	(2,706)	(4,025)	-
Total natural gas and oil sales	$179,093	$321,877	$175,187
Average Sales Price (2)			
Natural gas (per Mcf)	$3.12	$6.98	$5.33
Oil (per Bbl)	$55.03	$89.77	$60.65
Natural gas equivalent (per Mcfe)	$4.20	$8.42	$6.26
Average Lifting Cost (per Mcfe) (2) (3)	$0.83	$1.07	$0.90

(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold or other property interest we own.
(2) See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Natural Gas and Oil Sales for amounts per operating area.
(3) Lifting costs represent natural gas and oil lease operating expenses, exclusive of ad valorem and severance taxes, on a per unit basis.

Natural Gas Sales

We sell our natural gas to other gas marketers, utilities, industrial end-users and other wholesale gas purchasers. We generally sell the natural gas that we produce under contracts with indexed monthly pricing provisions. Virtually all of our contracts include provisions wherein prices change monthly with changes in the market, for which certain adjustments may be made based on 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, our revenues from the sale of natural gas are directly proportional, holding production volume constant, to market prices; as market prices decline, so too does our revenues, and as prices increase, our revenues increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry. We also enter into financial derivatives in order to reduce the impact of possible price instability regarding the physical sales market. See Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation: Results of Operations – Commodity Price Risk Management, Net, Natural Gas and Oil Derivative Activities and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

In general, we have been and expect to continue to be able to produce and sell natural gas from our wells without significant curtailment and at competitive prices. We do, however, experience limited curtailments from time to time due to pipeline maintenance and operating issues. Open access transportation through the country's interstate pipeline system gives us access to a broad range of markets. Whenever feasible, we obtain access to multiple pipelines and markets from each of our gathering systems seeking the best available market for our natural gas at any point in time.

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Oil Sales

Our wells in the Wattenberg Field produce natural gas as well as oil. As of December 31, 2009, oil represented 15.1% of our total equivalent reserves, and for the year then ended, accounted for approximately 17.9% of our natural gas and oil production and 39.7% of our natural gas and oil sales revenue.

We are currently able to sell all the oil that we can produce under existing sales contracts with petroleum refiners and marketers. We do not refine any of our oil production. Our crude oil production is sold to purchasers at or near our wells under both short and long-term purchase contracts with monthly pricing provisions.

Well Operations

As of December 31, 2009, we had an interest in approximately 5,000 wells. We are paid a monthly operating fee for the portion of each well we operate that is owned by others, including our sponsored partnerships. 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.

Transportation and Gathering

We develop, own and operate gathering systems in some of our areas of operations. We also continue 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 our existing systems. Pipelines and related facilities can represent a significant portion of the capital costs of developing wells, particularly in new areas located at a distance from existing pipelines. We consider these costs in our evaluation of our leasing, development and acquisition opportunities.

Our natural gas and oil are transported through our own and third party gathering systems and pipelines, and we incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third-party processor or transporter. Capacity on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas transporters. While our ability to market our natural gas has been only infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. In order to meet pipeline specifications, we are required, in some cases, to process our gas before we can transport it. We typically contract with third parties in the Grand Valley and NECO areas of our Rocky Mountain Region and Appalachian Basin for firm transportation of our natural gas. We also may enter into firm sales agreements to ensure that we are selling to a purchaser who has contracted for pipeline capacity. These agreements are subject to the same limitations discussed above in this paragraph. See Note 11, Commitments and Contingencies, to our consolidated financial statements included in this report for our long-term firm sales, processing and transportation agreements for pipeline capacity.

Natural Gas Marketing

RNG specializes in the purchase, aggregation and sale of natural gas production in our Eastern operating areas. RNG purchases for resale natural gas produced by third party producers as well as natural gas produced by us, our affiliated partnerships and joint venture. The gas is marketed to third party marketers, natural gas utilities, as well as industrial and commercial customers, either directly through our gathering system, or through transportation services provided by regulated interstate pipeline companies. RNG's employees have extensive knowledge of natural gas markets in our areas of operations. Such knowledge assists us in maximizing our prices as we market natural gas purchased by RNG.

Our industry competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers. 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.

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Commodity Price Risk Management Activities

We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility with regard to our natural gas and oil sales and natural gas marketing. We utilize both financial and physical instruments. The financial instruments generally consist of collars, swaps and basis swaps and are NYMEX-traded and CIG and PEPL-based contracts. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price stability for committed and anticipated natural gas and oil purchases and sales, generally forecasted to occur within the next two to four-year period. Our policies prohibit the use of commodity derivatives for speculative purposes and permit utilization of derivatives only if there is an underlying physical position. We manage price risk on only a portion of our anticipated production, so the remaining portion of our production is subject to the full fluctuation of market pricing.

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

We are subject to price fluctuations for natural gas sold in the spot market and under market index contracts. RNG does not always hedge the area basis risk for third party trades with back-to-back fixed price purchases and sales. We continue to evaluate the potential for reducing these risks by entering into derivative transactions. In addition, we 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.

Governmental Regulation

While the prices of natural gas and oil are set by the market, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for natural gas and oil production depends on several factors beyond our control. These factors include regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas and oil 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 and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of natural gas and oil, to prevent waste of natural gas and oil, to protect rights among owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. In the western part of the U.S., the federal and state governments own a large percentage of the land and the rights to develop natural gas and oil. Generally, government leases are subject to additional regulations and controls not commonly seen on private leases. We take the steps necessary to comply with applicable regulations, both on our own behalf and as part of the services we provide to our drilling partnerships. We believe that we are 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 summary discussion of the regulation of the U.S. oil and natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which our operations may be subject.

Regulation of Natural Gas and Oil Exploration and Production. Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of natural gas and oil, the development, production and marketing of natural gas and oil 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, we 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. Additionally, other regulated matters include:

- bond requirements in order to drill or operate wells;
- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of well properties;
- the plugging and abandoning of wells; and
- the disposal of fluids.

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Our 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, 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 natural gas and oil 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 natural gas and oil we can produce from our wells and may limit the number of wells or the locations at which we can drill. Such laws and regulations may increase the costs of planning, designing, drilling, installing, operating and abandoning our natural gas and oil wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves. As a result, we are unable to predict the future cost or effect 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 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's, or FERC, jurisdiction over natural gas transportation was unaffected by the Decontrol Act.

We move natural gas through pipelines owned by other companies, and sell natural gas to other companies that also utilize common carrier pipeline facilities. Natural gas pipeline interstate transmission and storage activities are subject to regulation by the FERC under the Natural Gas Act of 1938, or 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 natural 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 natural 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 regulations govern how interstate pipelines communicate and do business with their affiliates. Interstate pipelines may not operate their pipeline systems to preferentially benefit their marketing affiliates.

Each interstate natural gas pipeline company establishes its rates primarily through the FERC’s rate-making 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; and
- volume throughput assumptions.

The availability, terms and cost of transportation affect our natural gas sales. In the past, FERC has undertaken various initiatives to increase competition within the 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 greater access to transportation 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. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen the increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in-gas, which could adversely affect cash flows from the affected area.

Additional proposals and proceedings that might affect the industry occur frequently in Congress, FERC, state commissions, state legislatures, and the courts. The 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. We cannot determine to what extent our future operations and earnings will be affected by new legislation, new regulations, or changes in existing regulation, at federal, state or local levels.

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Environmental Regulations

Our 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 tougher environmental legislation and regulations is expected to 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 industry in general, our business and prospects could be adversely affected.

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our 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.

We currently own or lease numerous properties that for many years have been used for the exploration and production of natural gas and oil. Although we believe that we have utilized good operating and waste disposal practices, and when necessary, appropriate remediation techniques, prior owners and operators of these properties may not have utilized similar practices and techniques, and hydrocarbons or other wastes may have been disposed of or released on or under the properties that we own or lease 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, or CERCLA, RCRA and analogous state laws, as well as state laws governing the management of natural gas and oil wastes. Under such laws, we 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 full 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. As an owner and operator of natural gas and oil wells, we may be liable pursuant to CERCLA and similar state laws.

Our operations may be subject to the Clean Air Act, or 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 our operations. The EPA and states have been developing regulations to implement these requirements. We 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 State of Colorado has also implemented new air emission regulations in 2009, which affect the industry, including our operations.

The Federal Clean Water Act, or CWA, and analogous state laws impose strict controls against the discharge of pollutants, including spills and leaks of oil and other substances. The CWA also regulates storm water run-off from natural gas and oil facilities and requires a storm water discharge permit for certain activities. Spill prevention, control, and countermeasure requirements of the CWA require appropriate containment terms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak.

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 us, to procure and implement Spill Prevention, Control and Counter-measures plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990, or 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. We are also subject to the CWA 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. Historically, we have not experienced any significant oil discharge or oil spill problems.

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In 2009, the State of Colorado's Oil and Gas Conservation Commission implemented new broad-based environmental and wildlife protection regulations for the industry. These regulations will increase our costs and may ultimately limit some drilling locations. Our expenses relating to preserving the environment have risen over the past few years and are expected to continue to rise in 2010 and beyond. Environmental regulations have had no materially adverse effect on our operations to date, but no assurance can be given that environmental regulations or interpretations of such regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on our business, financial condition or results of operations. See Note 11, Commitments and Contingencies – Litigation, Colorado Stormwater Permit, to our consolidated financial statements included in this report.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including, but not limited to, 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 natural gas. The occurrence of any of these could result in substantial losses to us 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. Our pipeline, gathering and distribution operations are subject to the many hazards inherent in the industry. These hazards include damage to wells, pipelines and other related equipment, damage to property 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 our facilities could adversely affect our ability to conduct our operations. In accordance with customary industry practice, we maintain 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 our operations and financial condition. We cannot predict whether insurance will continue to be available at premium levels that justify our purchase or whether insurance will be available at all. Furthermore, we are not insured against our economic losses resulting from damage or destruction to third party property, such as the Rockies Express pipeline; such an event could result in significantly lower regional prices or our inability to deliver gas.

Competition

We believe that our exploration, drilling and production capabilities and the experience of our management and professional staff generally enable us to compete effectively. We encounter competition from numerous other natural gas and oil companies, drilling and income programs and partnerships in all areas of operations, including drilling and marketing natural gas and oil and obtaining desirable natural gas and oil leases on producing properties. Many of these competitors possess larger staffs and greater financial resources than we do, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future depends upon our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We also face 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 natural gas and oil 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 2008, our industry experienced continued strong demand for drilling services and supplies which resulted in increasing costs. In 2009, due to industry slowdown, we experienced overall reductions in our operating and drilling costs. Factors affecting competition in the industry include price, location of drilling, availability of drilling prospects and drilling rigs, pipeline capacity, quality of production and volumes produced. We believe that we can compete effectively in the industry in each of the listed areas. Nevertheless, our business, financial condition and results of operations could be materially adversely affected by competition. We also compete with other natural gas and oil companies as well as companies in other industries for the capital we need to conduct our operations. The 2008-2009 turmoil in the capital markets made financing more expensive and difficult to obtain. In the event that we do not have adequate capital to execute our business plan, we may be forced to curtail our drilling and acquisition activities.

Employees

As of December 31, 2009, we had 326 employees, including 200 in production, 7 in natural gas marketing, 25 in exploration and development, 62 in finance, accounting and data processing, and 32 in administration. Our employees are not covered by a collective bargaining agreement. We consider relations with our employees to be very good.

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Our engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and some pipeline systems. In addition, we retain subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites, with our employees supervising the activities of the subcontractors.

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 our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

Risks Related to the Global Economic Environment

There may be a reoccurrence of the 2009 global economic environment which increased the magnitude and the likelihood of the occurrence of the negative consequences discussed in many of the risks factors that follow.

In particular, consider the risks related to (1) the rapid deterioration of demand for natural gas and oil resulting from the economic environment and the related negative effects on natural gas and oil pricing, and (2) the effect of the credit constraints on our business, including the severe reduction in the availability of credit for drilling or to finance acquisitions. Also consider the interplay between these two risks: decline in natural gas and oil prices can lead to a reduction in the borrowing base for our credit line, and hence a reduction in our credit available for drilling. Similarly, further reductions in natural gas and oil prices could result in some of our assets becoming uneconomic to exploit, which would reduce our reserves, which in turn would reduce our borrowing base and the credit available to us. These factors could result in less drilling and production by us, and could thereby adversely affect our profitability and could limit our ability to execute our business plan. These factors could also make it impossible or extremely expensive to extend the term of our revolving credit line. The global economic environment also increases the potential of counterparty failure risk for both the banks which are parties to our natural gas and oil derivative holdings and for payments from purchasers of our natural gas and oil. Lastly, inability to ascertain the ultimate depth and duration of the economic environment could cause us to refrain from capital expenditures in order to maintain higher liquidity; our uncertainty and caution could result in significantly reduced drilling and hence reduced future production, which in turn may result in reduced reserves, resulting in a reduced borrowing base and availability of funds from our credit facility. All these risks could have a significant adverse effect on our business and our financial results. Any additional deterioration in the domestic or global economic conditions will further amplify these risks.

There may be a reoccurrence of the 2009 disruptions in the global financial markets and the related economic environment may further decrease the demand for natural gas and oil and the prices of natural gas and oil, thereby limiting our future drilling and production, and thereby adversely affecting our profitability.

During much of 2009, prices for natural gas and oil decreased over 60% from the 2008 peak. The well-publicized global financial market disruptions and the related economic environment may further decrease demand for natural gas and oil and therefore lower natural gas and oil prices. If there is such an additional reduction in demand, the continued production of gas may increase current oversupply and result in still lower gas prices. There is no certainty how long this low price environment will continue. We operate in a highly competitive industry, and certain competitors may have lower operating costs in such an environment. Furthermore, as a result of these disruptions in the financial markets, it is possible that in future years we would not be able to borrow or otherwise raise sufficient funds to sustain or increase capital expenditures. Such market conditions may also make it more difficult or impossible for us to finance acquisitions, through either equity or debt; acquisitions have historically been a major source of growth for us. We may also have difficulty finding partners to develop new drilling prospects and to build the pipeline systems needed to transport our gas. Inability of third parties to finance and build additional pipelines out of the Rockies and elsewhere could cause significant negative pricing effects. Any of the above factors could adversely affect our operating results.

Risks Related to Our Business and the Industry

Natural gas and oil prices fluctuate unpredictably and a decline in natural gas and oil prices can significantly affect the value of our assets, our financial results and impede our growth.

Our revenue, profitability and cash flow depend in large part upon the prices and demand for natural gas and oil. The markets for these commodities are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas and oil prices have a significant effect on our cash flow and on the value of our reserves, which can in turn reduce our borrowing base under our senior credit agreement. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control, including national and international economic and political factors and federal and state legislation. The prices in much of 2009 have been too low to economically justify many drilling operations, and it is uncertain how long such low pricing shall persist.

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The prices of natural gas and oil are volatile, often fluctuating greatly. Lower natural gas and oil prices may not only reduce our revenues, but also may reduce the amount of natural gas and oil that we can produce economically. As a result, we may have to make substantial additional downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write-down operating assets to fair value, as a non-cash charge to earnings. We assess impairment of capitalized costs of proved natural gas and oil 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 may be sold. In 2009, we recorded an impairment charge of $2.8 million related to our undeveloped leasehold acreage in North Dakota, and in 2008, we recorded impairment charges totaling $12.8 million related to our proved oil and gas properties, primarily related to our properties in the Fort Worth Basin and in North Dakota. There were no impairment charges recorded during 2007. We may incur impairment charges in the future, which could have a material adverse effect on the results of our operations.

A substantial part of our natural gas and oil production is located in the Rocky Mountain Region, making it vulnerable to risks associated with operating primarily in a single geographic area.

Our operations have been focused on the Rocky Mountain Region, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Because our operations are not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of natural gas and oil produced from the wells in the region, natural disasters, restrictive governmental regulations, transportation capacity constraints, curtailment of production or interruption of transportation, and any resulting delays or interruptions of production from existing or planned new wells.

Historically, natural gas prices in the Rocky Mountain Region often fell disproportionately when compared to other markets, due in part to continuing constraints in transporting natural gas from producing properties in the region. Because of the concentration of our operations in the Rocky Mountain Region, such price decreases are more likely to have a material adverse effect on our revenue, profitability and cash flow than those of our more geographically diverse competitors. Although current natural gas prices in the Rocky Mountain Region are not steeply discounted to NYMEX, there can be no assurance as to such continuation.

Our estimated natural gas and oil 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 our reserves.

Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas and oil 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. Independent petroleum engineers prepare our estimates of natural gas and oil reserves using pricing, production, cost, tax and other information that we provide. The reserve estimates are based on certain assumptions regarding future natural gas and oil 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 natural gas and oil attributable to any particular group of properties;
- future depreciation, depletion and amortization ("DD&A") rates and amounts;
- impairments in the value of our assets;

- the classifications of reserves based on risk of recovery;
- estimates of the future net cash flows; and
- timing of our capital expenditures.

Some of our reserve estimates must be made with limited production history, which renders these reserve estimates less reliable than estimates based on a longer 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 natural gas and oil recovered being different from earlier reserve estimates.

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The present value of our estimated future net cash flows from proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. As of December 31, 2009, the estimated discounted future net cash flows from proved reserves are based on prior year average prices, and are no longer based on selling prices in effect at year end. However, factors such as actual prices we receive for natural gas and oil and hedging instruments, the amount and timing of actual production, amount and timing of future development costs, supply of and demand for natural gas and oil, and changes in governmental regulations or taxation also affect our actual future net cash flows from our natural gas and oil properties.

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas and oil 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 SEC) we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our natural gas and oil properties or the industry in general.

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

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

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.

Acquisitions of producing properties and undeveloped properties have been an important part of our historical growth. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future natural gas and oil prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform engineering, geological and geophysical reviews of the acquired properties, which we believe is generally consistent with industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited.

Our focus on acquiring producing natural gas and oil properties may increase our potential exposure to liabilities and costs for environmental and other problems existing on acquired properties. Often we are not entitled to contractual indemnification associated with acquired properties. Normally, we acquire interests in properties on an "as is" basis with no or limited remedies for breaches of representations and warranties, as was the case in the acquisitions of assets from EXCO Resources Inc. and Castle Gas Company, as well as the acquisition of all shares of Unioil, Inc. We could incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, in our acquisitions for which we have limited or no contractual remedies or insurance coverage.

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. For example, in the Castle acquisition, we acquired interests in wells which we will need to operate together with other partners, we acquired pipelines that we will need to operate and expect we will need to commit to drilling in the acquired areas to achieve the expected benefits. Consequently, we may not be able to efficiently realize the assumed or expected economic benefits of properties that we acquire, if at all.

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When drilling prospects, we may not yield natural gas or oil in commercially viable quantities.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of natural gas or oil bearing rocks. However, our geologists cannot 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 given the available data and technology. If a well is determined to be dry or uneconomic, which can occur even though it contains some oil or natural 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 natural gas and oil to be profitable. If we drill a dry hole or unprofitable well on current and future prospects, the profitability of our operations will decline and our value 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.

We may not be able to identify enough attractive prospects on a timely basis to meet our development needs, which could limit our future development opportunities.

Our geologists have identified a number of potential drilling locations on our existing acreage. These drilling locations must be replaced as they are drilled for us to continue to grow our reserves and production. Our ability to identify and acquire new drilling locations depends on a number of uncertainties, including the availability of capital, regulatory approvals, natural gas and oil prices, competition, costs, availability of drilling rigs, drilling results and the ability of our geologists to successfully identify potentially successful new areas to develop. Because of these uncertainties, our profitability and growth opportunities may be limited by the timely availability of new drilling locations. As a result, our operations and profitability could be adversely affected.

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

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and oil can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations 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. We maintain insurance against various losses and liabilities arising from operations; however, insurance against all operational risks is not available. Additionally, our 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 effect on our business activities, financial condition and results of operations.

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Under the "successful efforts" accounting method that we use, unsuccessful exploratory wells must be expensed in the period when they are determined to be non-productive, which reduces our net income in such periods and could have a negative effect on our profitability.

We have conducted exploratory drilling and plan to continue exploratory drilling in 2010 in order to identify additional opportunities for future development. Under the "successful efforts" method of accounting that we use, 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, we anticipate that some or all of our exploratory wells may not be productive. The costs of such unsuccessful exploratory wells could result in a significant reduction in our profitability in periods when the costs are required to be expensed and have a negative effect on our debt covenants.

Increasing finding and development costs may impair our profitability.

In order to continue to grow and maintain our profitability, we must annually add new reserves that exceed our yearly production at a finding and development cost that yields an acceptable operating margin and DD&A rate. Without cost effective exploration, development or acquisition activities, our production, reserves and profitability will decline over time. Given the relative maturity of most natural gas and oil 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 and oil properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values climbed toward historic highs during 2007 and the first half of 2008 on a per unit basis, particularly in the Rocky Mountain Region, and although 2009 pricing multiples were stable these values may continue to increase in the future. This increase in finding and development costs results in higher DD&A rates. If the upward trend in finding and development costs continues, we will be exposed to an increased likelihood of a write-down in carrying value of our natural gas and oil properties in response to falling commodity prices and reduced profitability of our operations.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves, and ultimately our profitability.

The industry is capital intensive. We expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas and oil reserves. To date, we have financed capital expenditures primarily with bank borrowings, cash generated by operations and our 2008 senior note issuance. We intend to finance our future capital expenditures with cash flow from operations, funds from our 2009 sale of equity, capital contributed to our joint venture by our joint venture partner and other existing and planned financing arrangements. Our cash flows from operations and access to capital are subject to a number of variables, including:

• our proved reserves;
• the amount of natural gas and oil we are able to produce from existing wells;
• the prices at which natural gas and oil are sold;
• the costs to produce natural gas and oil; and
• our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decreases as a result of lower natural gas and oil prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas and oil prices, or we incur operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at planned levels, and our profitability may be adversely affected.

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

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

Seasonal weather conditions and lease stipulations designed to protect various wildlife affect natural gas and oil operations in the Rocky Mountains. In certain areas, including parts of the Piceance Basin in Colorado, drilling and other natural gas and oil activities are restricted or prohibited by lease stipulations, or prevented by weather conditions, for up to six months out of the year. This limits our 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 additional or increased costs or periodic shortages. These constraints and the resulting high costs or shortages could delay our operations and materially increase operating and capital costs and therefore adversely affect our profitability.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

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

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

Market conditions or the unavailability of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our 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 our business. We may be required to shut in wells for the lack of a market or because of inadequacy, unavailability or the pricing associated with natural gas pipelines, gathering system capacity or processing facilities. If that were to occur, we would be unable to realize revenue from those wells until we made production arrangements to deliver the product to market. Thus, our profitability would be adversely affected.

Our derivative activities could result in financial losses or reduced income from failure to perform by our counterparties or from changes in prices.

We use derivatives for a portion of our natural gas and oil production from our own wells, our partnerships and for natural gas purchases and sales by our marketing subsidiary to achieve a more predictable cash flow, to reduce exposure to adverse fluctuations in the prices of natural gas and oil, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us 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 that we receive.

In addition, derivative arrangements may limit the benefit from changes in the prices for natural gas and oil and may require the use of our resources to meet cash margin requirements. Since we do not designate our derivatives as hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of derivatives are recorded in our income statements, and our net income is subject to greater volatility than if our derivative instruments qualified for hedge accounting. For instance, if natural gas and oil prices rise significantly, it could result in significant non-cash charges each quarter, which could have a material negative effect on our net income.

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

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

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

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

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

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

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

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

Competition in the industry is intense, which may adversely affect our ability to succeed.

The industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce natural gas and oil, 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 natural gas and oil properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil 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 we can, which can adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because many companies in our industry have greater financial and human resources, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties. These factors could adversely affect the success of our operations and our profitability.

The current trend is to increase regulation of our operations and industry. We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our 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 natural gas and oil wells. Under these laws and regulations, we 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 us 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.

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Part of the regulatory environment includes federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation of conservation practices and protection of correlative rights by state governments. These regulations affect our operations, increase our costs of exploration and production and limit the quantity of natural gas and oil that we can produce and market. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals, drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase our financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff.

Illustrative of this trend are the regulations implemented in 2009 by the State of Colorado, which focus on the industry. These multi-faceted regulations significantly enhance requirements regarding natural gas and oil permitting, environmental requirements and wildlife protection. Permitting delays and increased costs could result from these final regulations.

Other potential laws and regulations affecting us include the following:

- State and federal initiatives to further regulate hydraulic fracturing, including the so-called “Frac Act,” which would amend the Federal Drinking Water Act, if adopted, would require disclosure of chemicals used in fracturing as well as other restrictions, which could lead to operational delays and increased costs.
- The 2011 federal budget, as initially proposed, contains several provisions harmful to the oil and gas industry; most importantly it would limit our ability to deduct intangible drilling costs in the year incurred, as provided under current law. This could have an adverse financial effect on us and on the economic viability of any future drilling.
- Several bills in Congress, if passed, would establish a "cap and trade" system regarding greenhouse gas emissions. Companies would be assigned emission "allowances" under these bills which would decline each year. In addition, new EPA greenhouse gas monitoring and reporting regulations may affect us and the third parties that process our oil and natural gas.
- Several federal regulatory proposals, if they became law, would limit the use of over-the-counter (OTC) derivatives, including the oil and gas price hedging we currently use. Limits on the use of OTC instruments could impair our use of these derivatives and could limit our ability to protect our cash flows and reduce oil and gas price risk.
- New or increased severance taxes have been proposed in several states, including Pennsylvania. This could adversely affect the existing operations in these states and the economic viability of future drilling.

Litigation has been commenced against us pertaining to our royalty practices and payments; the cost of our defending these lawsuits, and any future similar lawsuit, could be significant and any resulting judgments against us could have a material adverse effect upon our financial condition.

In recent years, litigation has commenced against us and several other companies in our industry regarding royalty practices and payments in jurisdictions where we conduct business. For more information on the suits that currently relate to us, see Note 11, Commitments and Contingencies, to our consolidated financial statements included in this report. We intend to defend ourselves vigorously in these cases. Even if the ultimate outcome of this litigation resulted in our dismissal, defense costs 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 our management would have to appropriate to the defense. Although we cannot predict an eventual outcome of this litigation, a judgment in favor of a plaintiff could have a material adverse effect on our financial condition or profitability.

Any future failure to maintain effective internal control over financial reporting and/or effective disclosure controls and procedures could have a material adverse effect on the reliability of our financial statements and our ability to file public reports on time, raise capital and meet our debt obligations.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008 and 2009, and pursuant to those assessments, concluded that we did maintain effective internal control over financial reporting as of December 31, 2008 and 2009. However, as of December 31, 2007, management's assessment of the effectiveness of our internal control over financial reporting identified two material weaknesses as disclosed in our Annual Report on Form 10-K for the year then ended and filed with the SEC on March 20, 2008. The existence of a material weakness means there is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

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Any future failure to maintain effective internal control over financial reporting and/or effective disclosure controls and procedures could prevent us from being able to prevent fraud and/or provide reliable financial statements and other public reports. Such circumstances could harm our business and operating results, cause investors to lose confidence in the accuracy and completeness of our financial statements and reports, and have a material adverse effect on the trading price of our debt and equity securities and our ability to raise capital necessary for our operations. These failures may also adversely affect our ability to file our periodic reports with the SEC on time. Being late in filing our periodic reports with the SEC may result in the delisting of our common stock from the NASDAQ Stock Market or a default under our senior credit agreement, the indenture governing our outstanding 12% senior notes due 2018, and any other instruments governing debt that we may incur in the future. Ultimately, such defaults could lead to the acceleration of our debt obligations, and if an acceleration of our debt obligations were to occur, we may not have sufficient funds to repay those obligations immediately, and we would be forced to seek alternative repayment arrangements either through a bankruptcy or an out of court debt restructuring. Consequently, a future material weakness could lead to significant and negative changes to our financial condition and the value of our equity and debt securities.

Risks Associated with Our Indebtedness

Our credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations. Our lenders can unilaterally reduce our borrowing availability based on anticipated sustained natural gas and oil prices.

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

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

The indenture governing our outstanding senior notes and our senior credit agreement impose (and we anticipate that the indentures governing any other debt securities we may issue will also impose) restrictions on us that may limit the discretion of management in operating our business. That, in turn, could impair our ability to meet our obligations.

The indenture governing our outstanding senior notes and our senior credit agreement contain (and we anticipate that the indentures governing any other debt securities we may issue will also contain) various restrictive covenants that limit management's discretion in operating our business. In particular, these covenants limit our ability to, among other things:

• incur additional debt;
• make certain investments or pay dividends or distributions on our capital stock, or purchase, redeem or retire capital stock;

• sell assets, including capital stock of our restricted subsidiaries;
• restrict dividends or other payments by restricted subsidiaries;
• create liens;
• enter into transactions with affiliates; and
• merge or consolidate with another company.

These covenants could materially and adversely affect our ability to finance our future operations or capital needs. Furthermore, they may restrict our ability to expand, to pursue our business strategies and otherwise conduct our business. Our ability to comply with these covenants may be affected by circumstances and events beyond our control, such as prevailing economic conditions and changes in regulations, and we cannot assure you that we will be able to comply with them. A breach of any of these covenants could result in a default under the indenture governing our outstanding senior notes and any other debt securities we may issue in the future and/or our senior credit agreement. If there were an event of default under our indenture and/or the senior credit agreement, the affected creditors could cause all amounts borrowed under these instruments to be due and payable immediately. Additionally, if we fail to repay indebtedness under our senior credit agreement when it becomes due, the lenders under the senior credit agreement could proceed against the assets which we have pledged to them as security. Our assets and cash flow might not be sufficient to repay our outstanding debt in the event of a default. The occurrence of such an event would adversely affect our operations and profitability.

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Our senior credit agreement also requires us to maintain specified financial ratios and satisfy certain financial tests. Our ability to maintain or meet such financial ratios and tests may be affected by events beyond our control, including changes in general economic and business conditions, and we cannot assure you that we will maintain or meet such ratios and tests, or that the lenders under the senior credit agreement will waive any failure to meet such ratios or tests.

In addition, upon a change in control, we are required to offer to buy each senior note for 101% of the principal amount, plus unpaid interest. A change in control is defined to include: (i) when a majority of the Board of Directors are not continuing directors; (ii) when one person (or group of related persons) holds direct or indirect ownership of over 50% of our voting stock; or (iii) upon sale, transfer or lease of substantially all of our assets.

We may incur additional indebtedness to facilitate our acquisition of additional properties, which would increase our leverage and could negatively affect our business or financial condition.

Our business strategy includes the acquisition of additional properties that we believe would have a positive effect on our current business and operations. We expect to continue to pursue acquisitions of such properties and may incur additional indebtedness to finance the acquisitions. Our incurrence of additional indebtedness would increase our leverage and our interest expense, which could have a negative effect on our business or financial condition.

If we fail to obtain additional financing, we may be unable to refinance our existing debt, expand our current operations or acquire new businesses. This could result in our failure to grow in accordance with our plans, or could result in defaults in our obligations under our senior credit agreement or the indenture relating to our outstanding senior notes.

In order to refinance indebtedness, expand existing operations and acquire additional businesses or properties, we will require substantial amounts of capital. There can be no assurance that financing, whether from equity or debt financings or other sources, will be available or, if available, will be on terms satisfactory to us. If we are unable to obtain such financing, we will be unable to acquire additional businesses or properties and may be unable to meet our obligations under our senior credit agreement and the indenture relating to our outstanding senior notes or any other debt securities we may issue in the future. Such an event would adversely affect our operations and profitability.

Risks Associated with Our Joint Venture

The PDC Mountaineer LLC joint venture is dependent upon our equity partner (the “Investor”) and poses exit-related risks for us.

The board of managers of the joint venture consists of three representatives appointed by us and three representatives appointed by the Investor, each with equal voting power. The joint venture agreement generally requires the affirmative vote of a majority of the members of the board to approve an action, and we and the Investor may not always agree on the best course of action for the joint venture. If such a disagreement were to occur, we would not be able to cause the joint venture to take action that we believed to be in the best interests of the joint venture. Consequently, our best interests may not be advanced and our investment in the joint venture could be adversely affected. If there is a disagreement about a development plan and budget for the joint venture, the Investor is entitled to unilaterally suspend substantially all of the operations of the joint venture, which could have a material adverse impact on the results of operations of the joint venture and our investment. Such a suspension could last for up to two years, at which point either party could elect to dissolve the joint venture or to sell their ownership interests to a third party. The Investor is entitled to a preference with respect to liquidating distributions and proceeds from significant sales of ownership interests up to the amount of its contributed capital, which would diminish our returns if the value of the joint venture had declined at the time of the liquidation or sale.

After a “restricted period” which generally lasts for the four year years following the closing of the joint venture, the Investor can seek to sell its interest in the joint venture to a third party, subject to rights of first offer and refusal in favor of us. If we do not exercise those rights in a sale involving all of the Investor’s ownership interests, the Investor can exercise “drag-along” rights and compel us to sell all of our interests in the proposed transaction. Accordingly, if we possessed insufficient funds and were unable to obtain financing necessary to purchase the Investor’s interest under the rights of first offer and refusal, we may be required to sell our interest in the joint venture at a time when we may not wish to do so. Under these circumstances, our investment in the joint venture could be adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Information regarding our wells, production, proved reserves and acreage are included in Item 1 – Business and in Note 2, Summary of Significant Accounting Policies, to our consolidated financial statements included in this report.

Substantially all of our natural gas and oil properties, exclusive of our joint venture properties, have been mortgaged or pledged as security for our credit facility. Substantially all of our joint venture properties have, however, been pledged as collateral for the joint venture's derivative instruments. See Note 4, Derivative Financial Instruments, and Note 8, Long Term Debt, to our consolidated financial statements included in this report.

Facilities

We lease 26,480 square feet in downtown Denver, Colorado, which serves as our corporate offices, through September 2015. We own a 32,000 square feet administrative office building located in Bridgeport, West Virginia where we also lease approximately 5,000 and 17,700 square feet of office space in two additional buildings through March 2010 and October 2011, respectively.

We own or lease field operating facilities in the following locations:

- West Virginia: Bridgeport and Glenville
- Michigan: Ossineke
- Colorado: Evans, Parachute and Wray
- Pennsylvania: Indiana and Mahaffey

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 11, Commitments and Contingencies – Litigation, to our consolidated financial statements included in this report.

ITEM 4. [RESERVED]

PART II

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

Our authorized capital stock consists of 100,000,000 shares of common stock, par value $0.01 per share. Our common stock is traded on the NASDAQ Global Select Market under the ticker symbol PETD. The following table presents the range of high and low sales prices for our common stock for each of the periods presented.

	Price Range	
	High	Low
January 1 - March 31, 2008	$ 73.92	$ 50.75
April 1 - June 30, 2008	79.09	66.37
July 1 - September 30, 2008	68.76	34.15
	44.75	11.50

October 1 - December 31, 2008		
January 1 - March 31, 2009	27.91	9.39
April 1 - June 30, 2009	20.63	11.21
July 1 - September 30, 2009	19.14	12.50
October 1 - December 31, 2009	21.87	16.06

As of February 16, 2010, we had approximately 1,076 shareholders of record.

We have not paid any dividends on our common stock and currently intend to retain earnings for use in our business. We do not expect to declare cash dividends in the foreseeable future.

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The following table presents information about our purchases of our common stock during the three months ended December 31, 2009.

Period	Total Number of Shares Purchased (1)	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 - 31, 2009	796	$ 17.59	-	-
November 1-30, 2009	2,029	18.06	-	-
December 1-31, 2009	329	18.21	-	-
Total fourth quarter purchases	3,154	17.95		

(1) Purchases represent shares purchased pursuant to our stock-based compensation plans for payment of tax liabilities related to the vesting of securities and shares purchased pursuant to our non-employee director deferred compensation plan.

SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2009, with the cumulative total returns for the same period for the Standard Industrial Code ("SIC") Index, and the Standard and Poor's ("S&P") 500 Index. The SIC Index is a weighted composite of 386 crude petroleum and natural gas companies. The cumulative total shareholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2004, and in the S&P 500 Index and the SIC Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

	Year Ended December 31,					
	2004	2005	2006	2007	2008	2009
Petroleum Development Corporation	$100.00	$86.44	$111.62	$153.31	$62.41	$47.21
S&P 500 Index	100.00	104.91	121.48	128.16	80.74	102.11
SIC Index	100.00	143.67	186.81	262.61	153.66	206.42

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands, except per share data)				
Revenues:					
Natural gas and oil sales	$179,093	$321,877	$175,187	$115,189	$102,559
Sales from natural gas marketing	64,635	140,263	103,624	131,325	121,104
Commodity price risk management gain (loss), net (1)	(10,053)	127,838	2,756	9,147	(9,368)
Well operations, pipeline income and other	11,043	11,767	10,170	11,576	9,198
Total revenues	244,718	601,745	291,737	267,237	223,493
Costs and expenses:					
Natural gas and oil production and well operations costs	64,746	79,354	49,833	29,981	21,090
Cost of natural gas marketing	62,534	139,234	100,584	130,150	119,644
Exploration expense and impairment of natural gas and oil properties	22,887	45,105	23,551	8,131	11,115
General and administrative expense	53,985	37,715	30,968	19,047	6,960
Depreciation, depletion and amortization	131,004	104,640	70,885	33,735	21,116
Total costs and expenses	335,156	406,048	275,821	221,044	179,925
Gain on sale of leaseholds (2)	470	-	33,291	328,000	7,669
Income (loss) from operations	(89,968)	195,697	49,207	374,193	51,237
Interest income	254	591	2,662	8,050	898
Interest expense	(37,208)	(28,132)	(9,279)	(2,443)	(217)
Income (loss) from continuing operations before income taxes	(126,922)	168,156	42,590	379,800	51,918
Provision (benefit) for income taxes	(45,716)	59,089	16,505	146,698	19,373
Income (loss) from continuing operations	(81,206)	109,067	26,085	233,102	32,545
Income from discontinued operations, net of tax (3)	113	4,177	7,083	4,670	8,907
Net income (loss)	(81,093)	113,244	33,168	237,772	41,452
Less: net loss attributable to noncontrolling interests	(1,816)	(65)	(41)	-	-
Net income (loss) attributable to shareholders	$(79,277)	$113,309	$33,209	$237,772	$41,452
Amounts attributable to Petroleum Development Corporation shareholders:					
Income (loss) from continuing operations	$(79,390)	$109,132	$26,126	$233,102	$32,545
Income from discontinued operations, net of tax	113	4,177	7,083	4,670	8,907
Net income (loss) attributable to shareholders	$(79,277)	$113,309	$33,209	$237,772	$41,452

Earnings (loss) per share attributable to shareholders:					
Basic					
Income (loss) from continuing operations	$(4.83)	$7.41	$1.77	$14.88	$1.99
Income from discontinued operations	0.01	0.28	0.48	0.30	0.54
Net income (loss) attributable to shareholders	$(4.82)	$7.69	$2.25	$15.18	$2.53
Diluted					
Income (loss) from continuing operations	$(4.83)	$7.35	$1.76	$14.81	$1.98
Income from discontinued operations	0.01	0.28	0.48	0.30	0.54
Net income (loss) attributable to shareholders	$(4.82)	$7.63	$2.24	$15.11	$2.52

	As of December 31,				
	2009	2008	2007	2006	2005
	(in thousands)				
Total assets	$1,250,327	$1,402,704	$1,050,479	$884,287	$444,361
Working capital (deficit)	$32,936	$31,266	$(50,212)	$29,180	$(16,763)
Long-term debt	$280,657	$394,867	$235,000	$117,000	$24,000
Equity	$538,593	$512,275	$396,285	$360,144	$188,265

(1) See Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

(2) In July 2006, we sold a portion of our undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. See Note 17, Sale of Natural Gas and Oil Properties, to our consolidated financial statements included in this report.

(3) See Note 16, Discontinued Operations, to our consolidated financial statements included in this report.

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

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our consolidated financial statements and related notes to consolidated financial statements included in this report. Further, we encourage you to revisit Special Note Regarding Forward-Looking Statements on page 1 of this report.

Non-GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) attributable to shareholders" and "adjusted EBITDA," non-GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons and providing public guidance on possible future results. These measures are not measures of financial performance under GAAP and should be considered in addition to, not as a substitute for, cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP. The non-GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure. See Reconciliation of Non-GAAP Financial Measures below for a detailed description of these measures as well as a reconciliation of each to the nearest GAAP measure.

2009 Overview

Even with natural gas prices rebounding somewhat in the last two months of 2009 from earlier in the year, overall we experienced depressed natural gas prices during 2009 compared to 2008. As our production increased to 43.3 Bcfe for 2009 compared to 38.7 Bcfe for 2008, an increase of 11.8%, primarily due to drilling programs in 2007 and 2008, our average sales price declined 50.1% or $4.22 per Mcfe. While the significant changes in commodity prices have impacted our results of operations, we believe that we were successful in managing our operations to reduce the negative impacts through our derivative positions. Our realized derivative gains for 2009 of $107.3 million added an average of $2.48 per Mcfe produced during 2009.

These realized derivative gains were the key component in our ability to increase our operating cash flow by $4.8 million to $143.9 million for 2009 as compared to 2008. With our strong operating cash flows, proceeds from our equity offering, and the formation of our joint venture, which allowed us to monetize a portion of our Appalachian Basin assets, we were able to pay down our debt and improve our liquidity position during the global recession of 2009. This allows us flexibility and stability as we enter 2010.

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Results of Operations

Summary Operating Results

The following table presents selected information regarding our results of operations.

	Year Ended December 31,			Change	
	2009	2008	2007	2009-2008	2008-2007
	(dollars in thousands, except per unit data)				
Production (1)					
Natural gas (Mcf)	35,536,092	31,759,792	22,513,306	11.9 %	41.1 %
Oil (Bbls)	1,291,488	1,160,408	910,052	11.3 %	27.5 %
Natural gas equivalent (Mcfe) (2)	43,285,020	38,722,240	27,973,618	11.8 %	38.4 %
Mcfe per day	118,589	106,088	76,640		
Natural Gas and Oil Sales					
Natural gas	$110,735	$221,734	$119,991	-50.1 %	84.8 %
Oil	71,064	104,168	55,196	-31.8 %	88.7 %
Provision for underpayment of natural gas sales	(2,706)	(4,025)	-	32.8 %	*
Total oil and natural gas sales	$179,093	$321,877	$175,187	-44.4 %	83.7 %
Realized Gain on Derivatives, net (3)					
Natural gas	$89,464	$12,632	$7,350	*	71.9 %
Oil	17,881	(3,145)	(177)	*	*
Total realized gain on derivatives, net	$107,345	$9,487	$7,173	*	32.3 %
Average Sales Price (excluding gain/loss on derivatives)					
Natural gas (per Mcf)	$3.12	$6.98	$5.33	-55.3 %	31.0 %
Oil (per Bbl)	$55.03	$89.77	$60.65	-38.7 %	48.0 %
Natural gas equivalent (per Mcfe)	$4.20	$8.42	$6.26	-50.1 %	34.5 %
Average Sales Price (including gain/loss on derivatives)					
Natural gas (per Mcf)	$5.63	$7.38	$5.66	-23.7 %	30.5 %
Oil (per Bbl)	$68.87	$87.06	$60.46	-20.9 %	44.0 %
Natural gas equivalent (per Mcfe)	$6.68	$8.66	$6.52	-22.9 %	32.9 %
Average Lifting Cost (per Mcfe) (4)	$0.83	$1.07	$0.90	-22.4 %	18.9 %
Natural Gas Marketing (5)	$2,101	$1,029	$3,040	104.2 %	-66.2 %
Other Costs and Expenses					
Exploration expense and impairment of natural gas and oil properties	$22,887	$45,105	$23,551	-49.3 %	91.5 %
General and administrative expense	$53,985	$37,715	$30,968	43.1 %	21.8 %
Depreciation, depletion and amortization	$131,004	$104,640	$70,885	25.2 %	47.6 %

Interest Expense	$37,208	$28,132	$9,279	32.3 %	203.2 %

* Percentage change not meaningful or equal to or greater than 250%

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold or other property interest we own.
(2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one Bbl of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.
(3) We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility of our natural gas and oil sales. These amounts represent realized derivative gains and losses related to natural gas and oil sales, which do not include realized derivative gains and losses related to natural gas marketing.
(4) Lifting costs represent natural gas and oil lease operating expenses, exclusive of production taxes, on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing.

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Natural Gas and Oil Sales

The following tables present natural gas and oil production and average sales price by area.

	Year Ended December 31,				
				Change	
	2009	2008	2007	2009-2008	2008-2007
Production					
Natural gas (Mcf)					
Rocky Mountain Region	29,987,465	26,136,487	18,123,851	14.7 %	44.2 %
Appalachian Basin	4,010,511	3,902,183	2,711,300	2.8 %	43.9 %
Other	1,538,116	1,721,122	1,678,155	-10.6 %	2.6 %
Total	35,536,092	31,759,792	22,513,306	11.9 %	41.1 %
Oil (Bbls)					
Rocky Mountain Region	1,277,887	1,149,071	900,261	11.2 %	27.6 %
Appalachian Basin	9,589	6,623	5,490	44.8 %	20.6 %
Other	4,012	4,714	4,301	-14.9 %	9.6 %
Total	1,291,488	1,160,408	910,052	11.3 %	27.5 %
Natural gas equivalent (Mcfe)					
Rocky Mountain Region	37,654,787	33,030,913	23,525,417	14.0 %	40.4 %
Appalachian Basin	4,068,045	3,941,921	2,744,240	3.2 %	43.6 %
Other	1,562,188	1,749,406	1,703,961	-10.7 %	2.7 %
Total	43,285,020	38,722,240	27,973,618	11.8 %	38.4 %

	Year Ended December 31,				
				Change	
	2009	2008	2007	2009-2008	2008-2007
Average Sales Price (excluding gain/loss on derivatives)					
Natural gas (per Mcf)					
Rocky Mountain Region	$2.98	$6.57	$5.01	-54.6 %	31.1 %
Appalachian Basin	4.00	9.21	6.99	-56.6 %	31.8 %
Other	3.47	8.41	6.12	-58.7 %	37.4 %
Weighted average price	3.12	6.98	5.33	-55.3 %	31.0 %
Oil (per Bbl)					
Rocky Mountain Region	$55.01	$89.73	$60.62	-38.7 %	48.0 %
Appalachian Basin	57.24	88.80	59.08	-35.5 %	50.3 %
Other	55.36	100.79	68.31	-45.1 %	47.5 %
Weighted average price	55.03	89.77	60.65	-38.7 %	48.0 %
Natural gas equivalent (per Mcfe)					
Rocky Mountain Region	$4.24	$8.32	$6.18	-49.0 %	34.6 %
Appalachian Basin	4.05	9.24	7.02	-56.2 %	31.6 %
Other	3.53	8.52	6.20	-58.6 %	37.4 %
Weighted average price	4.20	8.42	6.26	-50.1 %	34.5 %

Although production increased in 2009, natural gas and oil sales revenue, excluding the provision for underpayment of gas sales, decreased $144.1 million compared to 2008. Contributing to this decrease was $163.3 million related to decreased natural gas and oil pricing in 2009 as compared to 2008, which was partially offset by a $19.2 million increase in production. The production increase of 11.8% for 2009, compared to 2008, was primarily due to our significant capital investment in 2008. Directly attributable to our decision to reduce our capital expenditures for new wells drilled, our production exit rate of 107 MMcfe/day at December 31, 2009, was lower than the 122 MMcfe/day at December 31, 2008. The effects of the decrease in natural gas and oil sales revenue was significantly reduced by realized derivative gains for 2009 of $107.3 million. See Commodity Price Risk Management, Net discussion below.

The increase in natural gas and oil sales revenue of $150.7 from 2007 to 2008, excluding the provision for underpayment of gas sales, was a result of a 38.4% increase in production and a 34.5% increase in average commodity sales prices. The increase in production which contributed $90.5 million of the increase was a result of the significant number of wells drilled in 2008 along with an October 2007 acquisition of oil and gas properties. The increase in average commodity sales prices contributed $60.2 million to the increase in natural gas and oil sales revenues from 2007 to 2008.

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Natural Gas and Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas and oil and our ability to market our production effectively. Natural gas and oil prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas prices 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 has resulted in a local market oversupply situation from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is driven predominantly by global supply and demand relationships.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes gas sold at CIG prices as well as gas sold at Mid-Continent or other nearby region prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX-based. This negative differential has narrowed in recent months and for two out of the last four months become a slight positive differential, which contradicts historical variances.

The table below presents the pricing basis or market for our natural gas and oil sales based on production for 2009. The pricing basis is the index that most closely relates to the price under which our natural gas and oil is sold.

Energy Market Exposure
as of December 31, 2009

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	CIG	Gas	41%
Colorado/North Dakota	NYMEX	Oil	18%
Piceance	San Juan Basin/Southern California	Gas	15%
Appalachian	NYMEX	Gas	10%
NECO	Mid Continent (Panhandle Eastern)	Gas	7%
Michigan	Mich-Con/NYMEX	Gas	4%
Wattenberg	Colorado Liquids	Gas	4%
Other	Other	Gas/Oil	1%
			100%

Natural Gas and Oil Production and Well Operations Costs. Natural gas and oil production and well operations costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties (whose income is included in well operations, pipeline income, and other) and certain production and engineering staff related overhead costs.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Lease operating expense	$35,965	$41,351	$25,210
Production taxes	9,262	18,740	12,252

Costs of well operations and pipeline income	6,923	5,694	5,126
Overhead and other production expenses	12,596	13,569	7,245
Total natural gas and oil production and well operations costs	$64,746	$79,354	$49,833

Lease Operating Expense. Lifting costs per Mcfe decreased 22.4% to $0.83 per Mcfe for 2009 from $1.07 per Mcfe for 2008. The decrease per Mcfe is primarily due to lower third party costs from service providers as a result of pressure by us to reduce costs as natural gas and oil prices deteriorated, our own cost reduction initiatives, and increased production, which allows us to spread the fixed portion of our production costs over the increased volume. Lifting cost per Mcfe increased 18.9% in 2008 from $0.90 per Mcfe in 2007. The increase was primarily due to general oil field services and wage inflation pressures in the high commodity sales pricing environment during 2008.

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Production Taxes. Production taxes decreased $9.5 million or 50.6% to $9.3 million in 2009 compared to 2008. Production taxes fluctuate with natural gas and oil sales. The decrease in 2009 is the result of the 44.4% decrease in natural gas and oil sales from 2008. The 2008 increase in production taxes of $6.5 million corresponds with the 83.7% increase in natural gas and oil sales from those in 2007.

Cost of well operations and pipeline income. The increases in cost of well operations and pipeline income for 2009 compared to 2008 were the result of costs related to pipeline maintenance projects offset in part by lower field services costs.

Overhead and other production expenses. Overhead and other production expenses decreased in 2009 compared to 2008 due to the lower cost of field services, including vehicles, lower rates from third parties and less work and services being performed in this low commodity price environment, offset in part by a $2.7 million accrual for firm transportation costs in the Piceance Basin based on a projected shortfall in minimum volume requirements. The increase from 2007 to 2008 of $6.3 million was due to significantly increased production, additional personnel in the production and engineering staffs, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers and significant general oil field services inflation pressures.

Commodity Price Risk Management, Net

Commodity price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our natural gas and oil production. Commodity price risk management, net does not include derivative transactions related to natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report for additional details of our derivative financial instruments.

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Commodity price risk management gain (loss), net:			
Realized gains (losses):			
Natural gas	$89,464	$12,632	$7,350
Oil	17,881	(3,145)	(177)
Total realized gains (losses), net	107,345	9,487	7,173
Unrealized gains (losses):			
Reclassification of realized (gains) losses included in prior periods unrealized	(84,655)	549	(4,843)
Unrealized gains (losses) for the period	(32,743)	117,802	426
Total unrealized gains (losses), net	(117,398)	118,351	(4,417)
Total commodity price risk management gain (loss), net	$(10,053)	$127,838	$2,756

Realized gains recognized in 2009 of $107.3 million are a result of lower natural gas and oil spot prices at settlement compared to the respective strike price. During 2009, we recorded unrealized losses on our CIG basis swaps of $33.9 million as the forward basis differential between NYMEX and CIG had continued to narrow along with unrealized losses of $15 million on our oil positions, offset by unrealized gains of $16.2 million on our natural gas positions.

During the first half of 2008, we experienced both realized and unrealized derivative losses as natural gas and oil prices were at or near record prices. During the second half of the year, due to the tumbling commodity prices, we had both significant realized and unrealized derivative gains. We ended the year with a net realized and unrealized derivative gain of $127.8 million. The unrealized gain includes a gain on our natural gas and oil positions of $120.5 million and an unrealized loss on our CIG basis swaps of $2.7 million.

Natural Gas and Oil Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in natural gas and oil prices. We have in place a variety of collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and oil production. Under our collar arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor price, the counterparty pays us. Under our commodity swap arrangements, if the applicable index rises above the swap price, we pay the counterparty; however, if the index drops below the swap price, the counterparty pays us. Under our basis protection swaps, if the differential widens beyond the basis swap price, then the counterparty pays us; however, if the differential narrows, then we pay the counterparty. Because we sell all of our physical natural gas and oil at similar prices to the indexes inherent in our derivative instruments, we ultimately realize a price related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price related to our swaps.

The following table presents our derivative positions (excluding the derivative positions designated to our affiliated partnerships) related to natural gas and oil sales in effect as of December 31, 2009, on our production by area. Our production volumes for the fourth quarter of 2009 were 292,190 Bbls of oil and 8.2 Bcf of natural gas.

	Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		Fair Value At December 31, 2009 (in thousands)
Commodity/Operating Area/Index	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price	
Natural Gas								
Rocky Mountain Region								
CIG								
1Q 2010	2,167,137	$7.50	$7.50	1,515,805	$9.20	-	$-	$10,540
4Q 2010	680,250	4.75	9.45	-	-	-	-	122
2011	1,020,375	4.75	9.45	959,743	5.81	-	-	161
PEPL								
1Q 2010	510,000	9.00	14.00	360,000	10.91	-	-	3,743
2Q 2010	300,000	5.00	8.90	300,000	6.49	-	-	482
3Q 2010	300,000	5.00	8.90	300,000	6.49	-	-	405
4Q 2010	360,000	5.55	9.38	296,260	6.28	-	-	307
2011	390,000	5.76	9.56	2,117,424	6.18	-	-	638
2012 - 2013	-	-	-	2,346,224	6.18	-	-	(76)
NYMEX								
1Q 2010	562,725	10.00	17.15	375,510	8.98	-	-	3,706
2Q 2010	152,202	5.85	10.15	3,055,239	6.01	2,636,837	(1.88)	(2,277)
3Q 2010	152,202	5.85	10.15	2,968,502	6.02	2,541,588	(1.88)	(2,835)
4Q 2010	568,990	5.94	9.15	1,757,987	6.66	1,793,953	(1.88)	(1,295)
2011	724,478	5.96	9.10	7,703,191	6.96	7,668,501	(1.88)	(4,471)
2012 - 2013	8,785,102	6.05	8.43	7,406,878	7.08	14,610,818	(1.88)	(11,167)

Appalachia								
NYMEX								
1Q 2010	21,128	10.00	17.15	703,960	5.31	-	-	(138)
2Q 2010	7,115	5.85	10.15	687,401	5.32	-	-	(155)
3Q 2010	7,115	5.85	10.15	662,401	5.32	-	-	(278)
4Q 2010	7,190	6.45	11.48	648,933	5.33	-	-	(568)
2011	8,383	6.61	11.60	2,401,807	6.35	-	-	46
2012 - 2013	-	-	-	71,454	7.24	-	-	43
Michigan								
NYMEX								
1Q 2010	264,996	10.00	17.15	49,688	9.89	-	-	1,366
2Q 2010	73,255	5.85	10.15	72,886	8.55	-	-	276
3Q 2010								