PETROLEUM DEVELOPMENT CORP
Form 10-K
February 27, 2009

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

FORM 10-K

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

For the fiscal year ended December 31, 2008

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.)

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

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

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

Title of Each Class	Name of 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 x

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (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 x 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 x	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨ (Do not check if a 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 x

The aggregate market value of our common stock held by non-affiliates on June 30, 2008, was $965,929,153 (based on the then closing price of $66.49).

As of February 23, 2009 there were 14,868,158 ares 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 2009 Annual Meeting of Shareholders.

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2008 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 refer to the registrant, Petroleum Development Corporation, together with its subsidiaries, proportionate share of its sponsored drilling partnerships and an entity in which it has a controlling interest.

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 regarding our business, financial condition, results of operations and prospects. 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 oil and natural gas 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 oil and natural gas;
- 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;
- 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 Securities and Exchange Commission (“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

General

We are an independent energy company engaged in the exploration, development, production and marketing of oil and natural gas. Since we began oil and natural gas 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 activities.

As of December 31, 2008, we owned interests in approximately 4,712 gross, 3,259 net, wells located primarily in the Rocky Mountain Region and the Appalachian and Michigan Basins with 753 billion cubic feet equivalent, or Bcfe, of net proved reserves, of which 88% was natural gas and 12% was oil.

During 2008, our production was 38.7 Bcfe, averaging 106.1 MMcfe per day, a 38.5% increase over 76.6 MMcfe per day produced in 2007. We replaced our 2008 production with 106 Bcfe of new proved reserves, net of dispositions, for a reserve replacement rate of 274%. Reserve replacement through the drillbit was 104 Bcfe, or 268% of production, and reserve replacement through acquisitions was 2 Bcfe, or 6% of production. Proved reserves grew 9.8% during 2008, from 686 Bcfe to 753 Bcfe, of which 44% were proved developed reserves.

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We make available free of charge on our website at www.petd.com our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports as soon as reasonably practicable after we electronically file these reports with, or furnish them to, the SEC. We will also make available to any shareholder, without charge, a copy of our Annual Report on Form 10-K, or any other filing, as filed with the SEC, by mail. For a mailed copy of a report, you may 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, other information, including our press releases, Bylaws, Committee Charters, Code of Business Conduct and Ethics, Shareholder Communication Policy, Director Nomination Procedures and the Whistleblower Hotline, is also available on our website. However, the information available on our website is not part of this report and is not hereby incorporated by reference.

Business Strategy

Our primary objective is to continue to increase shareholder value through the growth of our reserves, production, net income and cash flow. To achieve meaningful increases in these key areas, we maintain an active drilling program that focuses on low risk development of our oil and natural gas reserves, limited exploratory drilling and the acquisition of producing properties with significant development potential.

Drill and Develop

Our acreage holdings include positions in the Rocky Mountain Region and the Appalachian, Michigan and Fort Worth Basins. In the Rocky Mountain Region, we focus on developmental drilling in Northeastern Colorado, or NECO, the Wattenberg Field (both located in the DJ Basin), the Grand Valley Field, Piceance Basin, and additional limited development in North Dakota. We drilled 379 gross, 333.4 net, wells in 2008, compared to 349 gross, 276.3 net, wells in 2007. In addition, we seek to maximize the value of our existing wells through a program of well recompletions and refractures. During 2008, we recompleted and/or refraced a total of 125 wells compared to 181 in 2007. In 2009, with a limited inventory of available recompletion opportunities, we plan to recomplete and/or refrac 40 wells in 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, 2008, we had leases or other development rights to approximately 224,800 undeveloped acres, of which approximately 188,000 acres, or 83.5%, were in the Rocky Mountain Region. We plan to drill approximately 166 gross, 144.1 net, wells in 2009, excluding exploratory wells. To support future development activities, we have conducted exploratory drilling in the past and plan to drill seven wells in 2009, primarily in the Appalachian Basin. The goal of the exploration program is to develop new areas for us to include in our future development drilling activity.

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 the pipe reserves or 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 three acquisitions of assets or companies in our core operating area of the Wattenberg Field in Colorado and acquired assets in southwestern Pennsylvania within close proximity to our existing assets in the Appalachian Basin. We had no significant acquisitions of properties in 2008. We expect to continue to evaluate acquisition opportunities. See Note 14, Acquisitions, to our accompanying consolidated financial statements included in this report.

Manage Risk

We seek opportunities to reduce the risk inherent to our business in the oil and natural gas industry by focusing our drilling efforts primarily on lower risk development wells and by maintaining positions in several different geographic regions and markets. 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 due to our success in that area over the past several years. However, we benefit from operational diversity in the Rocky Mountain Region by maintaining significant activity and production in three separate areas, including the Grand Valley Field of the Piceance Basin in western Colorado, the Wattenberg Field in north central Colorado and the NECO area. 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. We expect that future activities may include some level of exploratory drilling when the economic environment and commodity price models justify such risks. We view exploratory activities as having the potential to identify new development opportunities at a cost competitive to the current cost of acquiring proven locations.

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To help manage the risks associated with the oil and natural gas industry, we maintain a conservative financial approach and proactively employ strategies to reduce the effects of commodity price volatility. We also believe that successful oil and natural gas marketing is essential to risk management and profitable operations. To further this goal, we utilize Riley Natural Gas, or RNG, a wholly-owned subsidiary, to manage the marketing of our oil and natural gas and our use of oil and natural gas commodity derivatives as risk management tools. This allows us to maintain better control over third party risk in sales and derivative activities. We use oil and natural gas derivatives contracts primarily to reduce the effects of volatile commodity prices. We currently have derivative contracts in place on a significant 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 for which volumes are not limited. As of December 31, 2008, we had oil and natural gas hedges in place covering 52% of our expected oil production and 62% of our expected natural gas production in 2009. Further, while our derivative instruments are utilized to manage the impact of price volatility of our oil and natural gas production, they do not qualify for use of hedge accounting under the terms of SFAS No. 133, requiring us to recognize changes in the fair value of our derivative positions in earnings each reporting period and, therefore, resulting in the potential for significant earnings volatility. See Note 1, Summary of Significant Accounting Polices – Derivative Financial Instruments, to our accompanying consolidated financial statements included in this report.

Business Segments

We divide our operating activities into four segments:

- oil and gas sales;
- natural gas marketing activities;
- well operations and pipeline income; and
- oil and gas well drilling operations.

See Note 16, Business Segments, to our accompanying consolidated financial statements included in this report.

Oil and Gas Sales

Our oil and gas sales segment is our largest business segment based on revenue. This segment reflects revenues and expenses from production and sale of oil and natural gas. During 2008, approximately 84.8% of our oil and gas sales revenue was generated by the Rocky Mountain Region, 10.9% by the Appalachian Basin and 4.3% by the Michigan Basin. As of the end of 2008, our total proved reserves were located as follows: Rocky Mountain Region 82%, Appalachian Basin 15% and Michigan 3%. The majority of our undeveloped acreage is in the Rocky Mountain Region, where we focused our 2008 drilling activities. This segment represents approximately 133% of our income before income taxes for the year ended December 31, 2008.

Natural Gas Marketing Activities

Our natural gas marketing activities segment is comprised of our wholly-owned subsidiary, 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 we have gained significant expertise in the natural gas end-user market. We do not take speculative positions on commodity prices, and we employ derivative strategies to manage the financial effects of commodity price volatility. Our natural gas marketing segment represented approximately 1% of our income before income taxes for the year ended December 31, 2008.

Well Operations and Pipeline Income

We operate approximately 95.5% of the wells in which we own a working interest. With respect to wells in which we 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. Our well operations and pipeline income segment represented approximately 2% of our income before income taxes for the year ended December 31, 2008.

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Oil and Gas Well Drilling Operations

Our drilling and development segment reflects results of drilling and development activities conducted for affiliated and non-affiliated parties. Historically, we have engaged in these activities primarily through sponsoring drilling partnerships, which allowed us to share the risks and costs inherent in drilling and development operations with our investor partners. Beginning with our third sponsored drilling partnership in 2005, we have drilled partnership wells on a "cost-plus" basis, which means that we bill our investor partners for the actual drilling costs plus a fixed drilling fee. Prior to our cost-plus drilling arrangements, drilling was conducted on a "footage" basis, where the Company bore the risk of changes in costs. In addition, we have typically purchased a 20% to 37% working interest in the wells developed through these partnerships. In September 2006, we raised approximately $90 million through investor subscriptions in one drilling partnership, and in August 2007, we raised approximately $90 million through an additional drilling partnership.

Our oil and gas well drilling segment represented approximately 3% of our income before income taxes for the year ended December 31, 2008. In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008. However, a portion of the funds available for drilling from the 2007 partnership were advanced and unexpended at the end of 2007. The majority of these funds were used in 2008 for drilling and completion activities, a portion of which was recognized as income in 2008. The funds remaining as of December 31, 2008, will be used for completion activities to be conducted in 2009. Currently, we do not plan to sponsor a drilling partnership in 2009 and anticipate that our oil and gas well drilling segment's contribution to operating income will decline significantly in 2009.

Areas of Operations

We focus our exploration, development and production efforts in three primary geographic regions:

- Rocky Mountain Region;
- Appalachian Basin; and
- Michigan Basin.

During 2008, we generated approximately 85.6% of our production from Rocky Mountain Region wells, 10.2% of our production from Appalachian Basin wells and 4.2% of our production from Michigan Basin wells. 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. In 1999, we began operations in the Rocky Mountain Region. Our Rocky Mountain Region is divided into four operating areas: (1) Grand Valley Field, (2) Wattenberg Field, (3) NECO area and (4) North Dakota area. Our Rocky Mountain Region includes approximately 320,000 gross acres of leasehold and 2,408 gross, 1,542 net, oil and natural gas wells in which we own an interest. The general details of each area within the region are further outlined below:

- Grand Valley Field, Piceance Basin, Garfield County, Colorado. We commenced operations in the area in late 1999 and currently own an interest in 285 gross, 158.3 net, natural gas wells. Our leasehold position encompasses approximately 7,900 gross acres with approximately 5,200 net undeveloped acres remaining for development as of December 31, 2008. We drilled 62 gross, 54.4 net, wells in the area in 2008 and produced approximately 12.5 Bcfe net to our interests. 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 ranging from two to eight or more 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 and Adams Counties, Colorado. We commenced operations in the area in late 1999 and currently own an interest in 1,390 gross, 875.2 net, oil and natural gas wells. Our leasehold position encompasses approximately 75,900 gross acres with approximately 24,000 net undeveloped acres remaining for development as of December 31, 2008. We drilled 149 gross, 122.7 net, wells in the area in 2008 and produced approximately 15.4 Bcfe net to our interests. Wells drilled in the area range from approximately 7,000 to 8,000 feet in depth and generally target oil and gas 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.

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- NECO area. DJ Basin, Yuma County Colorado and Cheyenne County, Kansas. We commenced operations in the area in 2003 and currently own an interest in 717 gross, 504 net, natural gas wells. Our leasehold position encompasses approximately 141,600 gross acres with approximately 93,200 net undeveloped acres remaining for development as of December 31, 2008. We drilled 98 gross, 88.1 net, wells in the area in 2008 and produced approximately 5 Bcfe net to our interests. 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. New 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.

- North Dakota, Burke County. We commenced operations in the area in 2006 and currently own an interest in 13 gross, 3.7 net, oil and natural gas wells. We divested the majority of our Bakken project acreage in late 2007 (See Note 13, Sale of Oil and Gas Properties, to our accompanying consolidated financial statements included in this report). Our remaining leasehold encompasses two project areas in Burke County and encompasses approximately 75,100 gross acres with approximately 46,300 net undeveloped acres remaining for development as of December 31, 2008. The eastern area acreage is prospective for development of oil and gas reserves in the Nesson Formation. Nesson development wells are approximately 6,000 feet in depth with single or multiple horizontal legs to 4,000 feet or more in length for a measured length of 10,000 feet or more per leg. The westernmost acreage block is undeveloped and includes approximately 23,600 gross, 16,200 net acres. The western project targets exploratory horizontal drilling to the Midale/Nesson Formation at depths of approximately 6,800 feet with a lateral leg component of up to 6,100 feet. In 2009, we plan to drill up to four exploratory wells on our acreage with funding from an unrelated third party in exchange for an interest in our acreage position.

Appalachian Basin. We have conducted operations in the Appalachian Basin since 1969. Our leasehold position encompasses approximately 140,300 gross acres with approximately 19,400 net undeveloped acres remaining for development as of December 31, 2008. We own an interest in approximately 2,090 gross, 1,566.5 net, oil and natural gas wells in West Virginia, Pennsylvania and Tennessee. We drilled 63 gross/net wells in the area in 2008 and produced approximately 3.9 Bcfe net to our interests. The majority of our Appalachian leasehold is developed on approximately 40 acre spacing. Wells located in this area are approximately 4,500 feet deep and target predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs. We are currently evaluating the potential of the Marcellus Formation in West Virginia and Pennsylvania and have drilled three tests to date in West Virginia, two of which are in line.

Michigan Basin. We began operations in the Michigan Basin in 1997 with the bulk of drilling activity occurring prior to 2002. We own an interest in approximately 210 gross, 146.5 net, oil and natural gas wells that produced 1.6 Bcfe net to our interest in 2008. Wells in the area range from 1,000 to 2,500 feet in depth and produce gas from the Antrim Shale. We drilled 2 gross, 1.6 net, exploratory wells in 2008.

Fort Worth Basin. In addition to those operating areas above, we have an interest in approximately 12,500 gross, 9,100 net undeveloped acres, in Fort Worth Basin, northeastern Erath County, Texas. The leasehold acreage is prospective for the development of oil and natural gas reserves in the Barnett Shale formation at depths of approximately 5,000 feet. Development is typically with a horizontal component of approximately 3,000 feet or more, resulting in an approximate measured length of up to 8,000 feet or more in this area. In 2008, we commenced drilling operations and drilled three exploratory Barnett wells. These wells generated less than 1% of our 2008 production. Based on these results, we recorded impairments of both proved and unproved properties in this area in 2008. We are currently evaluating our future plans in this area and currently have no drilling activity planned in 2009.

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The table below sets forth our productive wells by operating area at December 31, 2008.

	Productive Wells					
	Gas		Oil		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	2,051	1,551.0	39	15.4	2,090	1,566.4
Michigan Basin	203	143.8	7	2.7	210	146.5
Rocky Mountain Region						
Wattenberg	1,365	856.0	25	19.3	1,390	875.3
Grand Valley	285	158.3	-	-	285	158.3
NECO Area	717	504.0	-	-	717	504.0
North Dakota	4	0.4	9	3.3	13	3.7
Wyoming	-	-	3	0.7	3	0.7
Total Rocky Mountain Region	2,371	1,518.7	37	23.3	2,408	1,542.0
Fort Worth Basin	4	4.0	-	-	4	4.0
Total Productive Wells	4,629	3,217.5	83	41.4	4,712	3,258.9

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, 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, farmouts and other development rights in these prospective areas. In most cases, to secure a lease, we pay a lease bonus and annual rental payments, converting, upon initiation of 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. As of December 31, 2008, we had leasehold rights to approximately 224,800 acres available for development.

Drilling Activities

The following table summarizes 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					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive (1)	349	303.8	327	258.9	216	129.8
Dry	8	8.0	11	9.7	6	4.6
	357	311.8	338	268.6	222	134.4

Total development						
Exploratory						
Productive (1)	7	7.0	1	0.2	8	2.8
Dry	10	9.6	7	4.5	1	0.5
Pending determination	5	5.0	3	3.0	-	-
Total exploratory	22	21.6	11	7.7	9	3.3
Total Drilling Activity	379	333.4	349	276.3	231	137.7

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(1) As of December 31, 2008, 94 of the 356 productive wells were awaiting gas pipeline connection, of which 38 were connected and turned in line by February 13, 2009.

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The following table sets forth the wells we drilled by operating area during the periods indicated.

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	63	63.0	8	8.0	-	-
Michigan Basin	2	1.6	3	3.0	1	1.0
Rocky Mountain Region	311	265.8	337	264.3	230	136.7
Fort Worth Basin	3	3.0	1	1.0	-	-
Total	379	333.4	349	276.3	231	137.7

We plan to drill approximately 166 gross wells, excluding exploratory wells, in 2009: 12 in the Appalachian Basin and 154 in the Rocky Mountain Region.

Much of the work associated with drilling, completing and connecting wells, including drilling, fracturing, logging and pipeline construction is performed under our direction by subcontractors specializing in those operations, as is common in the industry. When judged advantageous, material and services we use in the development process are acquired 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.

Financing of Company Drilling and Development Activities

We conduct development drilling activities for our own account and act as operator for other oil and gas owners. When conducting activities for our own account, we have historically funded our operations through our cash flows from operations, capital provided from our long term credit facility and, in 2008, from our senior notes issuance. In the future, we expect to continue to use these same sources, but may also use other sources of funding, including, but not limited to, asset sales, volumetric production payments, debt securities, convertible debt securities and equity offerings.

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 contribute 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 enter into a development agreement with the investor partner, pursuant to which we agree 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 becomes owner of a working interest in the well. In our financial reporting, we report only our proportionate share of oil and gas reserves, production, oil and gas sales and costs associated with wells in which other investors participate.

In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008 in order to focus our effort on continuing our growth through drilling and exploration. Currently, we have no plans to sponsor a partnership in 2009.

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 oil and gas 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.

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Production, Sales, Prices and Lifting Costs

The following table sets forth information regarding our production volumes, oil and natural gas sales, average sales price received and average lifting cost incurred for the periods indicated.

	Year Ended December 31,		
	2008	2007	2006
Production (1)			
Oil (Bbls)	1,160,408	910,052	631,395
Natural gas (Mcf)	31,759,792	22,513,306	13,160,784
Natural gas equivalent (Mcfe) (2)	38,722,240	27,973,618	16,949,154
Oil and Gas Sales (in thousands)			
Oil sales	$ 104,168	$ 55,196	$ 37,460
Gas sales	221,734	119,991	77,729
Royalty litigation provision	(4,025)	-	-
Total oil and gas sales	$ 321,877	$ 175,187	$ 115,189
Realized Gain (Loss) on Derivatives, net (in thousands)			
Oil derivatives - realized loss	$ (3,145)	$ (177)	$ -
Natural gas derivatives - realized gain	12,632	7,350	1,895
Total realized gain on derivatives, net	$ 9,487	$ 7,173	$ 1,895
Average Sales Price			
Oil (per Bbl) (3)	$ 89.77	$ 60.65	$ 59.33
Natural gas (per Mcf) (3)	$ 6.98	$ 5.33	$ 5.91
Natural gas equivalent (per Mcfe)	$ 8.42	$ 6.26	$ 6.80
Average Sales Price (including realized gain (loss) on derivatives)			
Oil (per Bbl)	$ 87.06	$ 60.46	$ 59.33
Natural gas (per Mcf)	$ 7.38	$ 5.66	$ 6.05
Natural gas equivalent (per Mcfe)	$ 8.66	$ 6.52	$ 6.91
Average Production Cost (Lifting Cost) per Mcfe (4)	$ 1.07	$ 0.90	$ 0.76

(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. This amount excludes realized and unrealized gains and losses on commodity based derivative instruments.

(4) Production costs represent oil and natural gas operating expenses which exclude production taxes.

Oil and Natural Gas Reserves

All of our natural gas and oil reserves are located in the U.S. We utilized the services of independent petroleum engineers to estimate our oil and gas reserves. For the years ended December 31, 2008 and 2007, our reserve estimates for the Appalachian and Michigan Basins are based on reserve reports prepared by Wright & Company and for the Rocky Mountain Region, reserve estimates are based on reserve reports prepared by Ryder Scott Company, L.P. For the year ended December 31, 2006, our reserve estimates for the Appalachian and Michigan Basins and NECO Area were based on reserve reports prepared by Wright & Company and our reserve estimates for the Rocky Mountain Region, with the exception of the NECO properties, were based on reserve reports prepared by Ryder Scott. The independent engineers' estimates are made using available geological and reservoir data as well as production performance data. The estimates are prepared with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X, Rule 4-10(a) and subsequent SEC staff interpretations and guidance. 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, oil and natural gas production, well test data, historical costs of operations and developments, product prices, or any agreements relating to current and future operations of properties and sales of production. Our independent reserve estimates are reviewed and approved by our internal engineering staff and management.

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The tables below set forth information regarding our estimated proved reserves. Reserves cannot be measured exactly, because reserve estimates involve subjective 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 oil and natural gas reserves we own.

	Proved Reserves as of December 31, 2008	2007	2006
Oil (MBbl)	15,037	15,338	7,272
Natural gas (MMcf)	662,857	593,563	279,078
Total proved reserves (MMcfe)	753,079	685,591	322,710
Proved developed reserves (MMcfe)	329,669	317,884	165,690
Estimated future net cash flows (in thousands) (1)	$ 1,056,890	$ 1,847,485	$ 525,454
Standardized measure (in thousands) (1)(2)	$ 356,805	$ 753,071	$ 215,662

(1) Estimated future net cash flow represents the 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, using prices and costs in effect at December 31for each respective year. For the weighted average wellhead prices used in our reserve reports, see Note 18, "Supplemental Oil and Gas Information," of our consolidated financial statements included in this report. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31for each respective year. 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.

(2) The standardized measure of discounted future net cash flow is calculated in accordance with Statement of Financial Accounting Standards ("SFAS") No. 69, which requires the future cash flows to be discounted. The discount rate used was 10%. Additional information on this measure, including a description of changes in this measure from year to year, is presented in Note 18, "Supplemental Oil and Gas Information," of our consolidated financial statements included in this report.

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	Proved Reserves as of December 31, 2008			
	Oil (MBbl)	Gas (MMcf)	Gas Equivalent (MMcfe)	Percent
Proved developed				
Appalachian Basin	29	73,447	73,621	22%
Michigan Basin	40	19,784	20,024	6%
Rocky Mountain Region				
Wattenberg	5,079	50,005	80,479	25%
Grand Valley	173	111,310	112,348	34%
NECO	-	42,042	42,042	13%
North Dakota	105	114	744	0%
Wyoming	8	-	48	0%
Total Rocky Mountain Region	5,365	203,471	235,661	72%
Fort Worth Basin	4	339	363	0%
Total proved developed	5,438	297,041	329,669	100%
Proved undeveloped				
Appalachian	-	39,380	39,380	9%
Rocky Mountain Region				
Wattenberg	9,340	62,284	118,324	28%
Grand Valley	259	258,824	260,378	62%
NECO	-	5,328	5,328	1%
Total Rocky Mountain Region	9,599	326,436	384,030	91%
Total proved undeveloped	9,599	365,816	423,410	100%
Proved reserves				
Appalachian	29	112,827	113,001	15%
Michigan	40	19,784	20,024	3%
Rocky Mountain Region				
Wattenberg	14,419	112,289	198,803	27%
Grand Valley	432	370,134	372,726	49%
NECO	-	47,370	47,370	6%
North Dakota	105	114	744	0%
Wyoming	8	-	48	0%
Total Rocky Mountain Region	14,964	529,907	619,691	82%
Fort Worth Basin	4	339	363	0%
Total proved reserves	15,037	662,857	753,079	100%

Acreage

The following table sets forth by operating area leased acres as of December 31, 2008.

	Developed		Undeveloped		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	117,800	113,000	22,500	19,400	140,300	132,400
Michigan Basin	16,800	14,800	10,000	8,400	26,800	23,200

Rocky Mountain Region						
Wattenberg	45,800	43,400	30,100	24,000	75,900	67,400
Grand Valley	2,700	2,700	5,200	5,200	7,900	7,900
NECO	23,200	19,300	118,400	93,200	141,600	112,500
North Dakota	8,300	4,800	66,800	46,300	75,100	51,100
Wyoming	300	100	19,200	19,200	19,500	19,300
Total Rocky Mountain Region	80,300	70,300	239,700	187,900	320,000	258,200
Fort Worth Basin	400	400	12,100	9,100	12,500	9,500
Total Acreage	215,300	198,500	284,300	224,800	499,600	423,300

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Title to Properties

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the oil and natural gas 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 curative 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. Two properties in our Grand Valley Field represent 49% of our total proved reserves.

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.

Natural Gas Sales

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 will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry. We also enter into financial derivatives such as puts, collars and swaps 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 - Oil and Gas Price Risk Management, Net, Oil and Gas Derivative Activities and Note 3, Derivative Financial Instruments, to our consolidated financial statements included in this report.

We sell our natural gas to other gas marketers, utilities, industrial end-users and other wholesale gas purchasers. During 2008, the natural gas we produced was sold at prices ranging from $2.77 to $13.85 per Mcf, depending upon well location, the date of the sales contract and other factors. Our weighted net average price of natural gas sold in 2008 was $6.98 per Mcf.

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 experience limited curtailments from time to time due to pipeline maintenance and operating issues. For instance, we experienced an approximate 10% to 15% curtailment of production volumes, approximately 10,000 Mcf per day, in the Piceance Basin due to limited compression and pipeline capacity throughout most of the fourth quarter in 2008. This interruption, due to third party infrastructure, was corrected in early 2009. 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.

Oil Sales

The majority of our wells in the Wattenberg Field in Colorado and our wells in North Dakota produce oil in addition to natural gas. As of December 31, 2008, oil represented 12% of our total equivalent reserves and accounted for approximately 32% of our oil and gas sales revenue for the year ended December 31, 2008.

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. During 2008, oil we produced sold at prices ranging from $19.82 to $132.38 per Bbl, depending upon the location and quality of oil. Our weighted net average price per Bbl of oil sold in 2008 was $89.77.

Natural Gas Marketing

Our natural gas marketing activities involve the purchase of natural gas from other producers and the sale of that natural gas along with the natural gas we produce for our own interest and that of our affiliated partnerships. 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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The natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers.

RNG specializes in the purchase, aggregation and sale of natural gas production in our Eastern operating areas. RNG markets the natural gas we produce and also purchases natural gas in the Appalachian Basin from other producers and resells it to other marketers, utilities or end users. 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 from PDC-operated wells. The gas is marketed to other 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.

We have entered into various sales, transportation and processing agreements with unrelated third parties which we sell to or who transports our natural gas. The following table sets forth information about long-term firm sales, processing and transportation agreements for pipeline capacity, which require a demand charge whether volumes are delivered or not.

Type of Arrangement	Location	Average Annual Volume (MMbtu)	Expiration Date
Firm sales and processing	Grand Valley	23,218,287	May 2016
Firm transportation	NECO Area	1,825,000	December 2010
Firm transportation	NECO Area	1,825,000	December 2016
Firm transportation (1)	Appalachian Basin	12,230,785	December 2022

(1) Contract is a precedent agreement and becomes effective when the planned pipeline is placed in service, estimated at this time to be 2012. Contract is null and void if pipeline is not completed.

Commodity Risk Management Activities

We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility with regard to our oil and natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas over-the-counter swaps, futures and option contracts for Appalachian and Michigan production, CIG and PEPL-based contracts for Colorado natural gas production and NYMEX-traded over-the-counter oil swaps and option contracts for Colorado oil production. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price stability for committed and anticipated oil and natural gas purchases and sales, generally forecasted to occur within the next two to three-year period, but no longer than five years beyond the derivative transaction date. Our policies prohibit the use of oil and natural gas futures, swaps or options for speculative purposes and permit utilization of derivatives only if there is an underlying physical position.

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 SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, definition of a derivative. Both types of derivatives (i.e., the physical deals and the cash settled contracts) are carried on the balance sheet at fair value with changes in fair values recognized currently in the 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. 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.

Well Operations

As of December 31, 2008, we had an interest in approximately 2,412 wells in the Rocky Mountain Region, 2,090 wells in the Appalachian Basin, and 210 wells in the Michigan Basin. On average, our interest ownership in these wells was approximately 69.2%.

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. If we purchase well interests belonging to investors in our sponsored partnerships, we then account for the purchased interests as being owned by us, which results in a decrease in well operations income.

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.

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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.

Governmental Regulation

While the prices of oil and natural gas are set by the market, other aspects of our business and the oil and natural gas industry in general are heavily regulated. The availability of a ready market for oil and natural gas 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 oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of oil and natural gas, to prevent waste of oil and natural gas, 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 oil and natural gas. 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 Oil and Natural Gas Exploration and Production

Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of oil and natural gas, the development, production and marketing of oil and natural gas and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, 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.

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 oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. Where wells are to be drilled on state or federal leases, additional regulations and conditions may apply. The effect of these regulations may limit the amount of oil and natural gas 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 oil and natural gas 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.

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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 ratemaking process. Key determinants in the ratemaking process are:

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure and related income taxes; 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 natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system was substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide transportation separate or “unbundled” from their sales service, and require that pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers. In many instances, the result of Order No. 636 and related initiatives has been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. Another effect of regulatory restructuring is 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 natural gas industry occur frequently in Congress, FERC, state commissions, state legislatures, and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue. 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.

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 could continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs and reduced access to the natural gas industry in general, 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.

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We currently own or lease numerous properties that for many years have been used for the exploration and production of oil and natural gas. 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 oil and natural gas 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 oil and natural gas 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 indicated it intends to implement new air regulations in 2009, which affect the oil and gas industry, including our operations, related to air emissions.

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 oil and gas 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.

In December 2008, the State of Colorado's Oil and Gas Conservation Commission finalized new broad-based environmental regulations for the oil and natural gas 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 2009 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 8, Commitments and Contingencies – Litigation, Colorado Stormwater Permit, to our accompanying 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 toxic 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 natural gas 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.

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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 oil and natural gas companies, drilling and income programs and partnerships in all areas of operations, including drilling and marketing oil and natural gas and obtaining desirable oil and natural gas 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 oil and natural gas 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 oil and natural gas exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future. During 2008, our industry experienced continued strong demand for drilling services and supplies which resulted in increasing costs. In 2009, due to industry slowdown, we are experiencing overall reductions in our operating and drilling costs. Factors affecting competition in the oil and natural gas industry include price, location of drilling, availability of drilling prospects and drilling rigs, pipeline capacity, quality of production and volumes produced. We believe that we can compete effectively in the oil and natural gas 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 oil and gas companies as well as companies in other industries for the capital we need to conduct our operations. Recently, turmoil in the capital markets has 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, 2008, we had 317 employees, including 205 in production, 8 in natural gas marketing, 28 in exploration and development, 49 in finance, accounting and data processing, and 27 in administration. 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. In 2008, the total number of Company employees increased by 61.

Our employees are not covered by a collective bargaining agreement. We consider relations with our employees to be very good.

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.

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Risks Related to the Global Economic Environment

The current global economic environment may increase 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 oil and natural gas resulting from the economic environment and the related negative effects on oil and gas 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 oil and gas 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 oil and gas 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 counterparty failure risk for both the banks which are parties to our oil and gas derivative holdings and for payments from purchasers of our oil and gas. 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. 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.

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

During the second half of 2008 and to date, prices for oil and gas decreased over 70%. The well-publicized global financial market disruptions and the related economic environment may further decrease demand for oil and gas and therefore lower oil and gas 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 sufficient funds to sustain or increase capital expenditures relative to 2008 expenditures, should we wish to make expenditures at those levels. 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 Natural Gas and Oil 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 from the fourth quarter of 2008 to date have been too low to economically justify many drilling operations, and it is uncertain how long such low pricing shall persist.

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 2008, we recorded an impairment charge of $7.5 million primarily related to our Texas Barnett Shale wells, and in 2006, we recorded an impairment charge of $1.5 million related to our Nesson field in North Dakota. There were no impairments during 2007. We may incur impairment charges in the future, which could have a material adverse effect on the results of our operations.

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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 affect 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.

During the last four months of 2008, natural gas prices in the Rocky Mountain Region 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, and although, in late 2008 we entered into a significant multi-year basis hedge in order to minimize the price risk of our concentration 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.

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 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.

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 (the SEC requires the use of year end prices). The estimated discounted future net cash flows from proved reserves are based on selling prices in effect on the day of estimate (year end). 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 natural gas and oil industry in general.

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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.

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. Our recent uneconomic drilling in the Texas Barnett Shale illustrates this risk.

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.

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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.

Our oil and gas well drilling operations segment has historically received most of its revenue from the partnerships we sponsor, and a reduction or loss of that business could reduce or eliminate the revenue, profit and cash flow associated with those activities.

Our oil and gas well drilling operations segment has, prior to 2008, received most of its revenue from the partnerships we sponsor. We sponsor oil and natural gas partnerships through a network of non-affiliated FINRA broker dealers. We did not offer a partnership in 2008 and do not anticipate offering a partnership in 2009. There can be no assurance that the network of brokers will be available or can be recreated if we wish to use partnerships to raise funds in future years. In that situation, our operations and profitability could be adversely affected.

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 2009 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 these increased costs could reduce our net income and have a negative effect on our profitability and ability to repay or refinance our indebtedness.

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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 depreciation, depletion and amortization 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 2008 on a per unit basis, particularly in the Rocky Mountain Region, and these values may continue to increase in the future. This increase in finding and development costs results in higher depreciation, depletion and amortization 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 natural gas and oil 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 public note issuance. We intend to finance our future capital expenditures with cash flow from operations and our existing and planned financing arrangements. Our cash flow from operations and access to capital is 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 oil and natural gas; 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.

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 periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase operating and capital costs and therefore adversely affect our profitability.

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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 of an operator to adequately perform operations, or an operator's breach of the applicable agreements, could reduce production and revenues and affect our profitability. The success and timing of drilling and development activities on properties operated by others therefore depends upon a number of factors outside of 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 lack of market or because of inadequacy, unavailability or the pricing associated with natural gas pipeline, gathering system capacity or processing facilities. If that were to occur, 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 our derivatives do not currently qualify for use of hedge accounting, 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 oil and gas 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.

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.

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

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As 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 natural gas and oil industry is intense, which may adversely affect our ability to succeed.

The natural gas and oil 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.

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.

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 by natural gas and oil-producing states of conservation practices and protection of correlative rights. 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 these risks are regulations recently enacted by the State of Colorado which focus on the oil and gas industry. These multi-faceted proposed regulations significantly enhance requirements regarding oil and gas permitting, environmental requirements, and wildlife protection. Permitting delays and increased costs could result from these final regulations.

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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 Item 3, Legal Proceedings. 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.

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 pursuant to this assessment, concluded that we did maintain effective internal control over financial reporting as of December 31, 2008. However, for each of the years in the three-year period ended December 31, 2007, management's assessment of the effectiveness of our internal control over financial reporting identified several material weaknesses as disclosed in our Annual Reports on Form 10-K for each of the years in the three-year period then ended and filed with the SEC on March 20, 2008, May 23, 2007, and May 31, 2006, respectively. 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.

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 oil and natural gas 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.

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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.

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.

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 and in Note 1, Summary of Significant Accounting Policies, to our consolidated financial statements included in this report.

Substantially all of our oil and natural gas properties have been mortgaged or pledged as security for our credit facility. See Note 6, Long Term Debt, to our accompanying consolidated financial statements included in this report.

Facilities

We own our 32,000 square feet corporate office building located in Bridgeport, West Virginia. We lease approximately 5,000 and 17,000 square feet of office space in two buildings near our current corporate office through March 2010 and November 2011, respectively. We lease 15,700 square feet of office space in downtown Denver, Colorado through March 2012, which effective March 1, 2009, will become our corporate headquarters.

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

- West Virginia: Bridgeport, Glenville and West Union
- 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 8, Commitments and Contingencies – Litigation and Note 17, Subsequent Events, to our consolidated financial statements included in this report.

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

None.

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.

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

	High	Low
2008		
First Quarter	$ 73.92	$ 50.75
Second Quarter	79.09	66.37
Third Quarter	68.76	34.15
Fourth Quarter	44.75	11.50
2007		
First Quarter	$ 55.20	$ 40.53
Second Quarter	55.24	44.59
Third Quarter	51.13	35.73
Fourth Quarter	61.91	41.65

As of February 23, 2009, we had approximately 1,107 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.

The following table presents information about our purchases of our common stock during the three months ended December 31, 2008.

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, 2008	118	$ 20.71	-	-
November 1-30, 2008	351	15.74	-	-
December 1-31, 2008	827	24.88	-	-
Total fourth quarter purchases	1,296	22.02		

(1) Pursuant to our stock-based compensation plans, the 1,296 shares purchased during the quarter represent purchases from our employees for their payment of tax liabilities related to the vesting of securities.

On October 16, 2006, our Board of Directors approved a share purchase program authorizing us to purchase up to 10% of our then outstanding common stock (1,477,109 shares) through April 2008. There were 1,465,089 shares that were authorized but not yet purchased as of December 31, 2007. Total shares purchased in 2008 pursuant to the program were 64,263 common shares at a cost of $4.4 million ($67.97 average price paid per share), including 63,756 shares from our executive officers at a cost of $4.3 million ($67.98 price paid per share). Shares purchased from employees, excluding executive officers, were generally purchased at fair market value based on the closing price on the date of purchase and were primarily purchased to satisfy the statutory minimum tax withholding requirement for restricted stock that vested in 2008. Shares purchased from executive officers were primarily pursuant to a separation agreement with our former president and to satisfy the statutory minimum tax withholding requirements for shares vested in 2008. The authorization to purchase the remaining 1,400,826 shares effectively expired on April 30, 2008. All shares purchased in accordance with the program have been subsequently retired.

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SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over a five year period ended December 31, 2008, with the cumulative total returns for the same period for a Standard Industrial Code Index, or SIC, and the Standard and Poor's, or S&P, 500 Index. The SIC Code Index is a weighted composite of 158 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, 2003, and in the S&P 500 Index and the SIC Code Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

	Year Ended December 31, 2003	2004	2005	2006	2007	2008
PETROLEUM DEVELOPMENT CORPORATION	$ 100	$ 163	$ 141	$ 182	$ 249	$ 102
SIC CODE INDEX	100	127	183	237	334	195
S&P 500 INDEX	100	111	116	135	142	90

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31, 2008	2007	2006	2005	2004
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 321,877	$ 175,187	$ 115,189	$ 102,559	$ 69,492
Sales from natural gas marketing activities	140,263	103,624	131,325	121,104	94,627
Oil and gas well drilling operations (1)	7,615	12,154	17,917	99,963	94,076
Well operations and pipeline income	11,474	9,342	10,704	8,760	7,677
Oil and gas price risk management gain (loss), net (2)	127,838	2,756	9,147	(9,368)	(3,085)
Other	293	2,172	2,221	2,180	1,696
Total revenues	609,360	305,235	286,503	325,198	264,483
Costs and expenses:					
Oil and gas production and well operations costs	78,209	49,264	29,021	20,400	17,713
Cost of natural gas marketing activities	139,234	100,584	130,150	119,644	92,881
Cost of oil and gas well drilling operations (1)	2,213	2,508	12,617	88,185	77,696
Exploration expense	45,105	23,551	8,131	11,115	-
General and administrative expense	37,715	30,968	19,047	6,960	4,506
Depreciation, depletion and amortization	104,575	70,844	33,735	21,116	18,156
Total costs and expenses	407,051	277,719	232,701	267,420	210,952
Gain on sale of leaseholds (3)	-	33,291	328,000	7,669	-
Income from operations	202,309	60,807	381,802	65,447	53,531
Interest income	591	2,662	8,050	898	185
Interest expense	(28,132)	(9,279)	(2,443)	(217)	(238)
Income before income taxes	174,768	54,190	387,409	66,128	53,478
Provision for income taxes	61,459	20,981	149,637	24,676	20,250
Net income	$ 113,309	$ 33,209	$ 237,772	$ 41,452	$ 33,228
Basic earnings per common share	$ 7.69	$ 2.25	$ 15.18	$ 2.53	$ 2.05
Diluted earnings per share	$ 7.63	$ 2.24	$ 15.11	$ 2.52	$ 2.00

	As of December 31, 2008	2007	2006	2005	2004
Total assets	$ 1,402,704	$ 1,050,479	$ 884,287	$ 444,361	$ 329,453
Working capital (deficit)	$ 31,266	$ (50,212)	$ 29,180	$ (16,763)	$ 231

Long-term debt	$	394,867	$	235,000	$	117,000	$	24,000	$	21,000
Shareholders' equity	$	511,581	$	395,526	$	360,144	$	188,265	$	154,021

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(1) In December 2005, we began entering into cost-plus drilling service arrangements, which are recorded on a net basis unlike our footage based arrangements which are recorded on a gross basis. See Note 1, "Summary of Significant Accounting Policies," to our accompanying consolidated financial statements included in this report. Further, we have not sponsored a drilling program since August 2007, related revenue continued to be recognized through 2008.

(2) See Note 3, "Derivative Financial Instruments", to our accompanying consolidated financial statements included in this report.

(3) In July 2006, we sold a portion of our undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. See Note 13, "Sale of Oil and Gas Properties," to our accompanying 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 Form 10-K, should be read in conjunction with our accompanying 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.

2008 Overview

The year 2008 was a year of unprecedented events: oil and natural gas prices soared to record and near record highs, respectively, through July; then, in the midst of U.S. credit turmoil and a worldwide economic slump, in December, oil prices fell to their lowest in four years and natural gas prices dropped almost by half. Our reaction to these events is one of caution. While we certainly felt the impact of these events, we believe that we were successful in managing our operations in such a manner that we were able to minimize the negative impacts while capitalizing on the positive impacts. Our strong derivative position eased the impact of the fall in oil and natural gas prices. We exit 2008 with $7.6 million in net realized derivative gains, $31.4 million in the fourth quarter alone. Further, we estimate the net fair value of our derivative positions, excluding the derivative positions attributed to our affiliated partnerships, as of December 31, 2008, to be $117.8 million. See 2009 Outlook and Liquidity and Capital Resources sections below for a discussion of the steps we plan to take in this uncertain economic environment.

For the second consecutive year, our net wells drilled increased double digits, up 20.7% in 2008 from 2007, which was up 100.1% from 2006. The increased drilling activity was fueled by the July 2006 sale of an undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado, providing us with cash proceeds of $353.6 million and our February 2008 senior notes offering with net proceeds of $196 million. We ended 2008 with interests in 4,712 gross, 3,259 net, wells located in the Rocky Mountain Region and the Appalachian and Michigan Basins. In 2008, we recompleted 104 wells in the Wattenberg Field and 21 wells in the Appalachian Basin.

The decline in prices during the fourth quarter of 2008 has resulted in $118.4 million in unrealized gains on derivatives for the year ended December 31, 2008. The $118.4 million in unrealized gains for the year is the fair value of the derivative positions as of December 31, 2008, less the related unrealized amounts recorded in prior periods. An unrealized gain is a non-cash item and there will be further gains or losses as prices decrease or increase until the positions mature or are closed. While the required accounting treatment for derivatives that do not qualify for hedge accounting treatment under SFAS No. 133 may result in significant swings in operating results over the life of the derivatives, the combination of the settled derivative contracts and the revenue received from the oil and gas sales at delivery are expected to result in a more predictable cash flow stream than would the sales contracts without the associated derivatives.

The average NYMEX and CIG prices for the next 24 months (forward curve) from the respective dates below are as follows:

Commodity	Index	December 31, 2007	June 30, 2008	December 31, 2008	February 13, 2009
Natural gas:	NYMEX	$ 8.12	$ 12.52	$ 6.62	$ 5.87
	CIG	6.78	8.86	4.49	4.13
Oil:	NYMEX	90.79	140.15	57.49	53.07

The dramatic commodity price declines from June 30, 2008, through December 31, 2008, relative to our current derivative positions, resulted in the significant unrealized derivative gains in 2008. If there are further price declines in 2009, unrealized derivatives gains on our current positions are expected to continue.

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2009 Outlook

We project that our 2009 production will be approximately 44.4 Bcfe or a 15% increase over 2008 production. Our 2009 capital budget of $120 million to $140 million represents an approximate 60% decrease compared to 2008. We selected this level of spending with the goal of remaining debt neutral to help maintain adequate liquidity during 2009. We realize that oil and gas prices may vary considerably from our projections. We use oil and natural gas derivatives contracts in order to reduce the effects of volatile commodity prices. As of December 31, 2008, we had oil and natural gas hedges in place covering 52% of our expected oil production and 62% of our expected natural gas production in 2009.

For 2009, our drilling plans continue to be focused primarily in the Rocky Mountain Region. We plan to drill approximately 166 gross wells, excluding exploratory wells, of which 154 are in the Rocky Mountain Region and 12 are in the Appalachian Basin. We are currently evaluating the exploration potential of the Marcellus Formation in the Appalachian Basin. Through a combination of lease, farmout and wellbore ownership, we operate over 2,100 wells within the Marcellus "Fairway" area. We currently have three wells drilled, two of which are in line, and seven additional vertical tests are planned in 2009.

Due to the continued decline in natural gas prices, in early 2009, we temporarily ceased all of our drilling operations in the Piceance Basin, resulting in the demobilization of the three contracted drilling rigs in this area. We have included in our approved 2009 capital budget $40.4 million for drilling and completion activities in the Piceance Basin. Should natural gas prices change materially from the projected levels, we will reevaluate our drilling options.

Results of Operations

Summary Operating Results

The following table sets forth selected information regarding our results of operations, including production volumes, oil and gas sales, average sales prices received, average sales price including realized derivative gains and losses, average lifting cost, other operating income and expenses for the years ended December 31, 2008, 2007 and 2006.

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Summary Operating Results for the

	Year Ended December 31,			Change	
	2008	2007	2006	2008-2007	2007-2006
Production (1)					
Oil (Bbls)	1,160,408	910,052	631,395	27.5%	44.1%
Natural gas (Mcf)	31,759,792	22,513,306	13,160,784	41.1%	71.1%
Natural gas equivalent (Mcfe) (2)	38,722,240	27,973,618	16,949,154	38.4%	65.0%
Oil and Gas Sales (in thousands)					
Oil sales	$ 104,168	$ 55,196	$ 37,460	88.7%	47.3%
Gas sales	221,734	119,991	77,729	84.8%	54.4%
Royalty litigation provision	(4,025)	-	-	*	*
Total oil and gas sales	$ 321,877	$ 175,187	$ 115,189	86.0%	52.1%
Realized Gain (Loss) on Derivatives, net (in thousands)					
Oil derivatives - realized loss	$ (3,145)	$ (177)	$ -	*	*
Natural gas derivatives - realized gain	12,632	7,350	1,895	71.9%	*
Total realized gain on derivatives, net	$ 9,487	$ 7,173	$ 1,895	32.3%	*
Average Sales Price					
Oil (per Bbl) (3)	$ 89.77	$ 60.65	$ 59.33	48.0%	2.2%
Natural gas (per Mcf) (3)	$ 6.98	$ 5.33	$ 5.91	31.0%	-9.8%
Natural gas equivalent (per Mcfe)	$ 8.42	$ 6.26	$ 6.80	34.4%	-7.9%
Average Sales Price (including realized gain (loss) on derivatives)					
Oil (per Bbl)	$ 87.06	$ 60.46	$ 59.33	44.0%	1.9%
Natural gas (per Mcf)	$ 7.38	$ 5.66	$ 6.05	30.5%	-6.5%
Natural gas equivalent (per Mcfe)	$ 8.66	$ 6.52	$ 6.91	32.9%	-5.6%
Average Lifting Cost per Mcfe (4)	$ 1.07	$ 0.90	$ 0.76	18.9%	18.4%
Other Operating Income(5) (in thousands)					
Natural gas marketing activities	$ 1,029	$ 3,040	$ 1,175	-66.2%	158.7%
Oil and gas well drilling operations	$ 5,402	$ 9,646	$ 5,300	-44.0%	82.0%
Costs and Expenses (in thousands)					
Exploration expense	$ 45,105	$ 23,551	$ 8,131	91.5%	189.6%
General and administrative expense	$ 37,715	$ 30,968	$ 19,047	21.8%	62.6%
Depreciation, depletion and amortization	$ 104,575	$ 70,844	$ 33,735	47.6%	110.0%
Interest Expense (in thousands)	$ 28,132	$ 9,279	$ 2,443	203.2%	*

*Percentage change not meaningful or equal to or greater than 250%
Amounts may not calculate due to rounding

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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. This amount excludes realized and unrealized gains and losses on commodity based derivative instruments.

(4) Production costs represent oil and gas operating expenses which exclude production taxes.

(5) Includes revenues and operating expenses.

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Oil and Gas Sales Activity

Oil and Natural Gas Production and Sales Activity by Area

	Year Ended December 31,				
				Change	
	2008	2007	2006	2008-2007	2007-2006
Production					
Oil (Bbls)					
Appalachian Basin	6,623	5,490	1,837	20.6%	198.9%
Michigan Basin	3,469	4,301	4,439	-19.3%	-3.1%
Rocky Mountain Region	1,150,316	900,261	625,119	27.8%	44.0%
Total	1,160,408	910,052	631,395	27.5%	44.1%
Natural gas (Mcf)					
Appalachian Basin	3,902,183	2,711,300	1,451,729	43.9%	86.8%
Michigan Basin	1,609,984	1,678,155	1,399,852	-4.1%	19.9%
Rocky Mountain Region	26,247,625	18,123,851	10,309,203	44.8%	75.8%
Total	31,759,792	22,513,306	13,160,784	41.1%	71.1%
Natural gas equivalent (Mcfe)					
Appalachian Basin	3,941,921	2,744,240	1,462,751	43.6%	87.6%
Michigan Basin	1,630,798	1,703,961	1,426,486	-4.3%	19.5%
Rocky Mountain Region	33,149,521	23,525,417	14,059,917	40.9%	67.3%
Total	38,722,240	27,973,618	16,949,154	38.4%	65.0%

Average Sales Price (excluding derivative gains/losses)					
Oil (per Bbl)					
Appalachian Basin	$ 88.80	$ 59.08	$ 60.14	50.3%	-1.8%
Michigan Basin	100.79	68.31	61.07	47.5%	11.9%
Rocky Mountain Region	89.73	60.62	59.31	48.0%	2.2%
Weighted average price	89.77	60.65	59.33	48.0%	2.2%
Natural gas (per Mcf)					
Appalachian Basin	$ 9.21	$ 6.99	$ 7.37	31.8%	-5.2%
Michigan Basin	8.41	6.12	6.53	37.4%	-6.3%
Rocky Mountain Region	6.57	5.01	5.62	31.1%	-10.9%
Weighted average price	6.98	5.33	5.91	31.0%	-9.8%
Natural gas equivalent (per Mcfe)					
Appalachian Basin	$ 9.24	$ 7.02	$ 7.39	31.6%	-5.0%
Michigan Basin	8.52	6.20	6.60	37.4%	-6.1%
Rocky Mountain Region	8.32	6.18	6.75	34.6%	-8.4%
Weighted average price	8.42	6.26	6.80	34.5%	-7.9%

Our oil and natural gas sales revenues have increased in each of the past two years, primarily due to increased volumes and higher average sales prices in 2008 and increased volumes partially offset by lower average sales prices in 2007. Increased volumes contributed $90.5 million and $75 million to the increase in oil and gas sales revenues in 2008 and 2007, respectively. The increases in oil and natural gas volumes over the past two years is attributable to the significant increase in the number of wells drilled for our own account in 2008 and 2007 compared to those drilled in prior years, and to a lesser extent, the acquisition of producing oil and gas properties in the fourth quarter of 2006. The production volumes and oil and gas sales revenue generated in 2007 from the acquisition of oil and gas properties made in early 2007 and December 2006 and their subsequent development were 6.5 Bcfe and $45.8 million, respectively.

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Oil and Natural Gas Pricing. Financial results depend upon many factors, particularly the price of oil and natural gas and our ability to market our production effectively. Oil and natural gas prices have been among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Oil and natural gas prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets have 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 facilities to increase pipeline capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is also driven strongly by supply and demand relationships.

The price we receive for a large portion of the 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.

Although 82.6% of our 2008 natural gas production came from the Rocky Mountain Region, much of our Rocky Mountain natural gas pricing is based upon other indices in addition to CIG. The table below identifies the pricing basis of our oil and natural gas pricing based on sales volumes for the year ended December 31, 2008. The pricing basis is the index that most closely relates to the price under which our oil and natural gas is sold.

Energy Market Exposure
as of December 31, 2008

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	Colorado Interstate Gas (CIG)	Gas	39%
Colorado/North Dakota	NYMEX	Oil	16%
NECO	Mid Continent (Panhandle Eastern)	Gas	12%
Piceance	San Juan Basin/Southern California	Gas	16%
Appalachian	NYMEX	Gas	10%
Michigan	Mich-Con/NYMEX	Gas	4%
Wattenberg	Colorado Liquids	Gas	2%
Other	Other	Gas/Oil	1%
			100%

Lifting Costs. Lifting costs per Mcfe, excluding production taxes which fluctuate with oil and natural gas prices, have increased approximately 18% annually since 2006, an increase of approximately 41% from 2006 to 2008. The increase is primarily due to general oil field services and wage inflation pressures. As production volumes increase when we add new wells, we can expect to see modest decreases in lifting costs as we work on improving and stabilizing our lifting costs. In our Rocky Mountain Region, we traditionally experience higher lifting costs due to severe winter conditions for costs such as snow removal from well and access roads, along with other weather related problems.

Oil and Gas Production and Well Operations Costs. In addition to increased production and the significant number of new wells operated, the increase in oil and gas production and well operations costs in each of the past two years is also attributable to 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 associated with the early 2007 and December 2006 acquisitions and significant general oil field services inflation pressures. Oil and gas production and well operations cost includes our lifting cost, production taxes, the cost to operate wells and pipelines for our sponsored partnerships and other third parties (whose income is included in well operations and pipeline income) and certain production and engineering staff related overhead costs. In October 2007, in conjunction with the acquisition of oil and gas properties (762 wells) located in southwestern Pennsylvania, we acquired a well services operation. The costs related to this operation are included in the statement of operations line item Oil and Gas Production and well Operations Costs.

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Oil and Gas Price Risk Management, Net

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Oil and gas price risk management, net:			
Realized gain (loss)			
Oil	$ (3,145)	$ (177)	$ -
Natural gas	12,632	7,350	1,895
Total realized gain, net	9,487	7,173	1,895
Unrealized gain (loss), net	118,351	(4,417)	7,252
	$ 127,838	$ 2,756	$ 9,147

Oil and gas price risk management, net includes realized gains and losses and unrealized changes in the fair value of oil and natural gas derivatives related to our oil and natural gas production. Oil and gas price risk management, net does not include commodity based derivative transactions related to transactions from natural gas marketing activities, which are included in sales from and cost of natural gas marketing activities. See Note 2, Fair Value of Financial Instruments, and Note 3, Derivative Financial Instruments, to the accompanying consolidated financial statements for additional details of our derivative financial instruments.

Oil and Gas Derivative Activities. We use various derivative instruments to manage fluctuations in oil and natural gas prices. We have in place a series of collars, fixed price swaps and basis swaps on a portion of our oil and natural gas production. Under the collar arrangements, if the applicable index rises above the ceiling price or swap, we pay the counterparty; however, if the index drops below the floor or swap, the counterparty pays us. Our production volumes for the quarter ended December 31, 2008, were 326,000 Bbls of oil and 9.3 Bcf of natural gas.

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The following table identifies our derivative positions (excluding the derivative positions allocated to our affiliated partnerships) related to oil and gas sales activities in effect as of December 31, 2008, on our production by area. No new positions have been entered into subsequent to December 31, 2008, through the date of this filing.

	Floors		Ceilings		Swaps (Fixed Prices)		Basis Swaps		
Commodity/ Index/ Operating Area	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Fair Value at December 31, 2008 (in thousands)
Natural Gas									
CIG									
Piceance Basin									
1Q 2009	-	$ -	-	$ -	2,388,158	$ 8.08	-	$ -	$ 9,340
2Q 2009	2,116,233	5.75	2,116,233	8.90	-	-	-	-	4,358
3Q 2009	2,116,233	5.75	2,116,233	8.90	-	-	-	-	3,523
4Q 2009	1,536,701	6.70	1,536,701	10.25	584,500	9.20			6,490
2010	1,672,131	6.80	1,672,131	10.90	876,751	9.20	4,274,703	1.88	7,788
2011	637,795	4.75	637,795	9.45	-	-	4,698,955	1.88	689
2012	-	-	-	-	-	-	4,733,113	1.88	(1,907)
2013	-	-	-	-	-	-	4,250,630	1.88	(2,846)
Wattenberg Field									
1Q 2009	-	-	-	-	1,702,203	8.07	-	-	6,640
2Q 2009	1,524,639	5.75	1,524,639	8.89	-	-	-	-	3,140
3Q 2009	1,524,639	5.75	1,524,639	8.89	-	-	-	-	2,538
4Q 2009	1,119,322	6.71	1,119,322	10.26	424,381	9.20	-	-	4,725
2010	1,170,071	6.90	1,170,071	10.98	636,571	9.20	2,682,613	1.88	5,410
2011	380,112	4.75	380,112	9.45	-	-	2,951,819	1.88	429
2012	-	-	-	-	-	-	2,953,958	1.88	(1,190)
2013	-	-	-	-	-	-	2,637,419	1.88	(1,766)
PEPL									
NECO									
1Q 2009	-	-	-	-	810,000	8.46	-	-	3,315
2Q 2009	720,000	6.14	720,000	10.81	-	-	-	-	1,332
3Q 2009	720,000	6.14	720,000	10.81	-	-	-	-	984
4Q 2009	580,000	7.81	580,000	12.68	240,000	10.91	-	-	2,669
2010	1,410,000	6.59	1,410,000	10.91	1,060,000	7.99	-	-	3,741
2011	300,000	6.00	300,000	10.10	-	-	-	-	92
NYMEX									
Appalachian and Michigan Basins									
1Q 2009	260,103	8.40	260,103	13.05	972,279	9.71	-	-	4,469

2Q 2009	905,212	7.13	905,212	12.85	429,743	9.09	-	-	2,836
3Q 2009	905,212	7.13	905,212	12.85	429,743	9.09	-	-	2,625
4Q 2009	868,186	9.00	868,186	15.66	429,457	9.09	-	-	3,367
2010	1,547,849	8.22	1,547,849	14.19	1,704,946	9.08	-	-	5,968
2011	232,277	6.75	232,277	12.13	800,844	9.60	-	-	1,731
2012	-	-	-	-	155,211	9.89	-	-	306
Total Natural Gas									80,796
Oil									
NYMEX									
Watenberg Field									
1Q 2009	-	-	-	-	154,188	90.52	-	-	6,428
2Q 2009	-		-	-	155,903	90.52	-	-	5,729
3Q 2009	-	-	-	-	157,615	90.52	-	-	5,291
4Q 2009	-	-	-	-	157,615	90.52	-	-	4,856
2010	-	-	-	-	529,664	92.96	-	-	14,702
Total Oil									37,006
Total Natural Gas and Oil									$ 117,802

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Natural Gas Marketing Activities

The increase in sales from natural gas marketing activities in 2008 compared to 2007 is primarily due to an increase in prices and increased unrealized gains on derivative instruments. The increase in costs of natural gas marketing activities in 2008 compared to 2007 is primarily due to an increase in prices and increased unrealized losses on derivative instruments.

In 2008, prices on sales and purchases were 31.8% higher on average than in 2007, resulting in a $27.8 million increase in sales and costs. The sales related unrealized gain on derivatives increased by $6.4 million and the cost of sales related unrealized loss on derivatives increased by $6.9 million. Volumes sold and purchased for resale decreased slightly by 2%.

The decrease in sales from natural gas marketing activities in 2007 compared to 2006 is primarily due to a decrease in prices and volumes sold and a decrease in unrealized gains on derivative instruments. The decrease in costs of natural gas marketing activities in 2007 compared to 2006 is also due to a decrease in prices and volumes purchased and a decrease in unrealized losses on derivative instruments.

In 2007, prices on sales and purchases were 5% lower on average than in 2006, resulting in a $5 million decrease in sales and costs. In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships. Natural gas sales and purchases related to the net 423 wells acquired no longer flowed through marketing activities; the result was a decline in sales from and costs of natural gas marketing activities of $12.2 million. This decline in partnership volumes was offset by an increase in non-partnership volumes sold and purchased amounting to $3.7 million, for a net volume effect of an $8.5 million decrease compared to 2006. The gain on unrealized sales decreased $14 million from a $12.3 million gain in 2006 to a $1.7 million loss in 2007. The gain on unrealized costs decreased $13.4 million from an $11.9 million loss in 2006 to a $1.5 million gain in 2007.

Our natural gas marketing segment specializes in the purchase, aggregation and sale of natural gas production in our eastern operating areas. Through our natural gas marketing segment, we market the natural gas we produce as well as our purchases of natural gas from other producers in the Appalachian Basin, including our affiliated partnerships. Our derivative activities related to natural gas marketing activities include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. We do not take speculative positions on commodity prices.

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Natural Gas Marketing Derivative Activities.

The following table identifies our derivative positions related to our gas marketing activities in effect as of December 31, 2008.

	Floors		Ceilings		Swaps (Fixed Prices)		Basis Swaps		
Commodity/ Derivative Instrument	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Fair Value at December 31, 2008 (in thousands)
Natural Gas Physical Sales									
1Q 2009	20,000	$ 6.50	-	$ -	112,400	$ 8.59	290,021	$ 0.37	$ 230
2Q 2009	-	-	-	-	43,132	9.20	72,493	0.29	119
3Q 2009	-	-	-	-	31,320	9.55	66,578	0.29	88
4Q 2009	-	-	-	-	9,293	8.36	38,266	0.51	14
2010	-	-	-	-	15,610	8.45	30,410	0.80	19
Financial Purchases									
1Q 2009	20,000	6.50	-	-	152,400	7.31	-	-	(207)
2Q 2009	-	-	-	-	43,132	8.11	-	-	(99)
3Q 2009	-	-	-	-	31,191	8.48	-	-	(74)
4Q 2009	-	-	-	-	29,293	10.77	-	-	(113)
2010	-	-	-	-	45,610	10.86	-	-	(157)
Financial Sales									
1Q 2009	-	-	10,000	10.30	580,900	9.13	226,665	0.32	1,879
2Q 2009	-		-	-	322,500	9.27	211,272	0.32	1,116
3Q 2009	-	-	-	-	250,500	9.39	141,250	0.32	812
4Q 2009	-	-	-	-	248,500	8.90	166,050	0.32	540
2010	-	-	-	-	695,000	8.71	-	-	1,040
2011				-	150,000	8.44	-	-	125
Physical Purchases									
1Q 2009	-	-	10,000	10.30	581,395	9.29	46,935	0.32	(1,762)
2Q 2009	-	-	-	-	322,995	9.44	46,874	0.32	(1,079)
3Q 2009	-	-	-	-	250,995	9.56	46,752	0.32	(788)
4Q 2009	-	-	-	-	228,665	9.60	15,584	0.32	(597)
2010	-	-	-	-	665,000	9.14	-	-	(1,146)
2011	-	-	-	-	150,000	8.61	-	-	(125)
Total Natural									$ (165)

Gas

Oil and Gas Well Drilling

The decrease in oil and gas well drilling operations revenue was due to our decision not to sponsor a drilling partnership in 2008 and our change from footage-based drilling arrangements to cost-plus drilling arrangements, which have differing revenue recognition presentations.

In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008. In August 2007, we completed our only sponsored drilling partnership offering in 2007. Drilling for the partnership commenced during the third quarter of 2007. From inception to December 31, 2008, $12.7 million in revenues had been recognized related to the 2007 drilling program. Advances for future drilling contracts held as of December 31, 2008, will be used for completion activities to be conducted in 2009. Currently, we do not plan to sponsor a drilling partnership in 2009 or in the foreseeable future. Consequently, we anticipate that our oil and gas drilling segment's contribution to operating income, which was $5.4 million, $9.6 million and $5.3 million in 2008, 2007 and 2006, respectively, will decline substantially in 2009. Thereafter, our oil and gas well drilling contribution to operating income will cease unless we undertake new drilling ventures.

Beginning with the last sponsored partnership in 2005 (for which revenue generating activities began in 2006), our partnership wells have been drilled on a "cost-plus" basis, which means that we charge the partnerships for the actual cost of the wells plus an agreed upon mark-up above that cost. Prior to that partnership, we had conducted most of our third-party drilling activities on a footage basis, pursuant to which we drilled the wells for a fixed price per foot drilled with additional chargeable items as provided for in the drilling agreement. Our services provided under the cost-plus drilling arrangements are reported net of recovered costs and reflected as revenue in oil and gas well drilling operations, whereas the revenues under the footage-based arrangements were recorded gross of related expenses. For the year ended December 31, 2006, the oil and gas well drilling segment's results included $5.4 million in revenues and $10 million in expenses related to footage based arrangements.

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Well Operations and Pipeline Income

In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships. Having acquired 423 net wells pursuant to the acquisition, we no longer record income for operating these wells and related pipelines. This decrease in revenue was offset in part by an increase in the number of new wells drilled and placed in service and pipeline systems we operate for our sponsored drilling partnerships as well as third parties. In October 2007, in conjunction with the acquisition of oil and gas properties located in southwestern Pennsylvania, we acquired a well services operation. The revenues related to this operation are included in the statement of operations line item Well Operations and Pipeline Income.

Gain on Sale of Leaseholds

In July 2006, we entered into a purchase and sale agreement with an unaffiliated party regarding the sale of our undeveloped leasehold located in the Grand Valley Field, Garfield County, Colorado, as filed with the Securities and Exchange Commission, or SEC, as Exhibit 10.3 to Form 10-Q for the period ended September 30, 2006. Total proceeds from the sale were $353.6 million, of which we recognized a $328 million gain on sale of leasehold in the third quarter of 2006.

In May 2007, we entered into a letter agreement amending the above mentioned purchase and sale agreement, relieving us of our obligation, in its entirety, to either drill 16 wells or pay liquidated damages of $1.6 million per undrilled well. As a result, we recognized the remaining deferred gain of $25.6 million in the second quarter of 2007.

In December 2007, we sold to the same unaffiliated party a portion of our North Dakota properties for approximately $34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and approximately 72,000 net undeveloped acres. We recorded a gain on sale of leaseholds of $7.7 million in the fourth quarter of 2007.

Other Costs and Expenses

Exploration Expense

The following table sets forth the major components of exploration expense.

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Impairment of proved oil and gas properties	$ 12,825	$ -	$ 1,510
Amortization/impairment of unproved properties	12,798	3,291	1,010
Exploratory dry holes	7,675	4,187	1,790
Geological and geophysical costs	2,121	6,299	2,234
	35,419	13,777	6,544
Operating and other	9,686	9,774	1,587
Total exploration expense	$ 45,105	$ 23,551	$ 8,131

We expanded exploratory drilling activities in 2005 and have generally believed that the additional risk and costs associated with exploratory drilling is justified by the potential to generate additional proved properties. However, we plan to reduce exploratory drilling in 2009 given the current economic conditions and focus primarily on development activities in our proven fields.

We assess our proved oil and gas properties for possible impairment 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 we reasonably estimate the commodity to be sold. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows. We assess our unproved oil and gas properties for possible impairment by field based on our historical experience, current market data, acquisition dates, average lease terms and the probability of being drilled.

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We recognized impairment losses on proved oil and gas properties of $12.8 million in 2008, consisting of $7.5 million related to our properties in the Fort Worth Basin, $3 million in our Bakken Field in North Dakota and $2.3 million in our Nesson Field, also in North Dakota. We also recognized impairment losses of unproved properties of $12.9 million, consisting primarily of $7.3 million related to our unproved properties in the Fort Worth Basin and amortization of approximately $5.6 million related to all of our other areas of operations. The $7.7 million of exploratory dry holes relates primarily to two Michigan wells, one New York well and one Colorado well.

In 2007, exploration expense includes $2.7 million of liquidated damages associated with the abandonment of an exploration agreement with an unaffiliated party and $1.1 million related to the write-off of the carrying value of the related acreage, $6.3 million in geological and geophysical costs related to seismic evaluation of various exploratory prospects and increased payroll and payroll related costs and other exploratory department costs.

In 2006, exploration expense includes $1.8 million related to one exploratory dry hole, $1.5 million related to an impairment charge on our Nesson Field in North Dakota and $2.2 million in geological and geophysical costs related to the seismic evaluation of our Northeast Colorado properties.

General and Administrative Expense

General and administrative expense has increased for the third consecutive year. However, 2008 is considered pivotal because the rate of increase is declining and we expect this trend to continue in 2009. It is this trend that we expect to continue in 2009. General and administrative expenses have been declining on a per Mcfe basis, from $1.12 per Mcfe in 2006 to $1.11 per Mcfe in 2007 and $0.97 per Mcfe in 2008.

The increase in general and administrative expense in 2008 compared to 2007 was primarily due to increased payroll and payroll related expenses, which includes $4.7 million related to agreements with two former executive officers: $3.2 million related to a separation agreement with our former president and $1.5 million related to an agreement for the retirement of our former chief executive officer. This increase was partially offset by a $2 million decrease in audit fees and a decrease in various other general and administrative expenses.

The increase in general and administrative expense in 2007 compared to 2006 was primarily due to increased costs related to increased payroll and payroll related expenses, which includes stock-based compensation expense related to the recruitment of professionals and key personnel in 2007. The increase in management personnel is attributable to the growth we are experiencing, the increase in the cost of recruiting and the higher compensation required to obtain experienced oil and gas personnel. We also experienced higher financial statement audit costs related to the late filing of our 2006 Form 10-K, higher compliance costs with the various provisions of the Sarbanes-Oxley Act, increased accounting assistance from third party consulting services and increased legal costs.

Depreciation, Depletion and Amortization

DD&A expense includes depreciation and amortization expense related of non-oil and natural gas properties as well as oil and natural gas properties. DD&A expense for non-oil and natural gas properties was $7.6 million, $4.3 million and $2 million in 2008, 2007 and 2006, respectively. DD&A expense related to oil and natural gas properties is directly related to reserves and production volumes. DD&A expense is primarily based upon year-end proved developed producing oil and gas reserves. These reserves are priced at the price of oil and natural gas as of December 31 each year. If prices increase, the corresponding volume of oil and gas reserves will increase, resulting in decreases in the rate of DD&A per unit of production. If prices decrease, as they did from 2007 to 2008, volumes of oil and gas reserves will decrease resulting in increases in the rate of DD&A per unit of production. See Note 18, Supplemental Oil and Gas Information – Unaudited, to our accompanying consolidated financial statements, for the average December 31 oil and natural gas prices used to determine year-end reserves and other reserve information. The cost to acquire acreage, drill, complete and equip new wells have risen significantly over the past five years along with oil and natural gas prices and is a major contributing factor for the increased DD&A rate in the table below:

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DD&A rates for our oil and gas properties are shown in the table below.

	Year Ended December 31, 2008	2007	2006
		(per Mcfe)	
Appalachian Basin (1)	$ 1.55	$ 1.32	$ 1.13
Michigan Basin	1.35	1.28	0.83
Rocky Mountain Region:			
Wattenberg Field (2)	3.47	2.99	2.34
Piceance Basin (3)	2.04	2.27	1.83
NECO	1.45	1.45	1.26
Weighted average	2.51	2.37	1.87

(1) The increase in DD&A rate for the Appalachian Basin in 2008 was due to the higher market price of a fourth quarter 2007 acquisition of 752 wells in southwestern Pennsylvania and the new wells drilled in 2008.
(2) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its oil production currently more than offsets this cost difference. The Wattenberg Field has produced volumes in excess of 85% of our total oil production in each of the years in the three-year period ended December 31, 2008.
(3) The decrease in DD&A rates for the Piceance Basin in 2008 compared to 2007 is the result of higher year-end 2008 oil and natural gas reserves, due primarily to the improvements in drilling and completion technology and expanded pipeline and compression capacity.

Non-Operating Income/Expense

Interest Income. The decreases in our interest income in 2008 and 2007 were the result of lower cash balances earning interest compared to 2006. In July 2006, we received $353.6 million in cash proceeds from the sale of undeveloped leaseholds. These proceeds earned interest income until reinvested in oil and gas properties in January 2007.

Interest Expense. The increases in our interest expense were primarily due to significantly higher average outstanding balances of our credit facility and, in 2008, our 12% senior notes offset in part by lower average interest rates in our bank credit facility. The average long-term debt in 2008 was $275.9 million compared to $132.5 million in 2007. Interest expense is net of capitalized interest. Interest costs capitalized in 2008, 2007 and 2006 were $2.6 million, $3 million and $1.6 million, respectively. We have historically utilized our daily cash balances to reduce our line of credit borrowings, thereby lowering our interest costs.

Provision for Income Taxes

Our 2008 effective income tax rate was 35.2% in 2008 compared to 38.7% in 2007 and 38.6% in 2006. This reduced rate reflects second and third quarter discrete benefits of $1.4 million for each period, related principally to the implementation of state tax strategies during each respective quarter. The impact of these strategies also affected our rate used to establish deferred taxes and resulted in a deferred tax benefit of $1 million in 2008.

Our effective tax rate, excluding the effect of discrete items, for 2008 was 37.3%, which was virtually unchanged from 2007 and slightly less than the 2006 rate of 38.4%. In 2008, the rate decreased primarily due to a 0.5% reduction in our effective state tax rate due to the benefit being realized from our implemented state tax planning strategies and a 0.7% reduction primarily related to reduced tax penalties. However, these 2008 rate decreases were offset by our permanent tax deductions resulting in a proportionately smaller effective rate benefit of 0.8% compared to 1.8% in 2007. In 2006, our permanent tax deduction for percentage depletion resulted in a proportionately smaller tax rate benefit of only 0.1%.

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Liquidity and Capital Resources

Cash flow from operations and our bank credit facility are the primary sources of liquidity for us to satisfy our operating expenses and fund our capital expenditures. We had $180.5 million of available borrowing capacity under our $375 million bank credit facility as of December 31, 2008. Cash provided by operating activities was $139.1 million for the current year period compared to $60.3 million in the prior year period. The $78.8 million increase in the current year period was primarily due to higher natural gas and oil prices through mid-2008 and higher volumes of oil and natural gas production and realized derivative gains primarily in the fourth quarter of 2008. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items which are primarily depreciation, depletion and amortization and unrealized gains and losses on derivative transactions. See the discussion under Results of Operations. Cash flow used in investing activities increased $55.6 million, or 21%, from $267.4 million for the year ended 2007 to $323 million in 2008. Substantially all of our investing activity involved drilling for oil and gas reserves during 2008. Cash flows provided from financing activities increased $52.6 million, or 54%, from $97.5 million to $150.1 million for the years ended December 31, 2007 and 2008, respectively. This increase was primarily due to the increase in proceeds from the issuance of our 12% senior notes of $200 million offset by net repayments on our bank credit facility.

Changes in market prices for oil and natural gas, our ability to increase production, the impact of realized gains and losses on our oil and natural gas derivative instruments and changes in costs are the principal determinants of the level of our cash flow from operations. Oil and natural gas sales for the year ended December 31, 2008, were approximately 85% higher than the prior year, resulting from a 34% increase in average oil and natural gas prices and a 38% increase in oil and natural gas production. While a decline in oil and natural gas prices would affect the amount of cash from operations that would be generated, we have oil and natural gas derivative positions in place, as of the date of this filing, covering 52% of our expected oil production and 62% of our expected natural gas production in 2009, at average prices of $90.52 per Bbl and $7.25 per Mcf, respectively. These contracts reduce the impact of price changes for a substantial portion of our 2009 cash from operations.

Our primary use of funds is for capital expenditures. As a result of the current unstable conditions in the commodity and financial markets, we have significantly reduced our planned 2009 capital expenditures to a range of $120 million to $140 million which represents an approximate 60% decrease from our 2008 capital expenditures. With this reduction, we estimate our 2009 production will increase by approximately 15% over 2008 in part due to increased production from wells drilled in the latter part of 2008. We believe, based on the current commodity price environment, our cash flow from operations will fund our reduced 2009 capital spending program allowing us to remain debt neutral during 2009. We expect to manage capital expenditures within our cash flow from operations in 2009 and for the foreseeable future until commodity prices and capital markets are more favorable. In order to continue to maintain or grow our production, we will need to commit greater amounts of capital in 2010 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flow from operations and liquidity under our credit facility as the sources of funding for our capital expenditures. Oil and gas produced from our existing properties declines rapidly in the first two years of production. We could not maintain our current level of oil and gas production and cash flow from operations if capital markets and commodity prices remain in their current depressed state for a prolonged period beyond 2009, which would have a material negative impact on our operations in 2010 and beyond.

We considered the possibility of a reduced available liquidity environment in planning our 2009 drilling program and believe we will have adequate cash flow from operations during the year to execute our planned capital expenditures without drawing additional funds from our credit facility. Currently, we operate approximately 95% of our properties, allowing us to control the pace of substantially all of our planned capital expenditures. Consequently, a substantial portion of our planned capital expenditures for 2009 and beyond could be deferred if market conditions worsen.

In addition to deferring capital expenditures to reduce borrowings under our credit facility, other sources of liquidity include the fair value of our oil and natural gas derivative positions, excluding the derivative positions attributed to our affiliated partnerships, of $117.8 million as well as our available cash balance which was $51 million as of December 31, 2008.

We have one significant future drilling commitment along with certain volume delivery requirements that will require us to expend $60 million in development drilling on our Wattenberg leases through 2011, provided that our counterparty in the agreement expands two gas processing facilities and maintains certain wellhead pressures by June 30, 2010. Our 2009 capital expenditure plan includes approximately $50 million related to this commitment. Failure to meet our drilling commitment would result in a maximum payment to the counterparty of $15 million in 2012; failure to meet our volume delivery commitments by December 31, 2012, would result in a maximum payment to the counterparty of $10 million in 2013. Failure of the counterparty to complete the required plant expansions results in a waiver of our $60 million capital and volume delivery requirements.

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We have experienced no impediments in our ability to access borrowings under our current bank credit facility. We continue to monitor market events and circumstances and their potential impacts on each of the thirteen lenders that comprise our bank credit facility. Our $375 million bank credit facility borrowing base is subject to size redeterminations each April and October based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base. We will be subject to a borrowing base redetermination in April 2009.

We increased our borrowing base in July 2008, and again in November 2008, to $300 million and $375 million respectively. The increases were driven primarily by increases in proved producing reserves from drilling operations. While we have continued to add producing reserves since our November 2008 redetermination, we believe the significant decrease in commodity prices and turmoil in the credit markets could have a negative impact on our borrowing base at our next redetermination in April 2009. Our credit facility matures in November 2010, and is payable in full at that time. We have begun discussions with our bank group with the intent of renewing the credit facility prior to November 1, 2009. There is no assurance all of the lenders in our credit facility will participate in the renewal and there is no assurance that our borrowing base will not be reduced from its current level as a result of the renewal or the loss of one or more lenders in our credit facility. Further, costs of capital have increased since we last amended our credit facility and we expect that interest and commitment fees under a new facility will be higher than in our current credit facility. See Note 6, Long Term Debt, to the accompanying consolidated financial statements. At December 31, 2008, we had $180.5 million available for borrowing under our $375 million credit facility. While we believe our borrowing base could be reduced as a result of redeterminations, we believe that producing reserves added since our last redetermination and our oil and natural gas derivative positions in place could mitigate the risk of a significant decrease in our borrowing base in 2009. We also believe that while costs of capital have increased for credit facilities like ours, the impact of an increase in interest and commitment fees on our outstanding balance and commitments will not have a material adverse effect on our liquidity in 2009. Our credit facility matures in November 2010. If economic conditions deteriorate further in 2009 and 2010, our ability to renew our credit facility and provide adequate liquidity to continue our drilling programs could be negatively impacted in 2010 and beyond.

We are subject to quarterly financial debt covenants on our bank credit facility. Our key credit facility debt covenants require that we maintain: 1) total debt of less than 3.75 times earnings before interest, taxes, depreciation, amortization and capital expenditures ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. As of December 31, 2008, our total debt was 1.5 times EBITDAX and our adjusted working capital ratio was 1.6 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our oil and gas derivative instruments and adding our available borrowings on our bank credit facilities to our current assets. In addition, the impact of any current portion of our debt is eliminated from the current liabilities. Therefore, any change in our available borrowings under our credit facility impacts our working capital ratio.

We believe we have sufficient liquidity and capital resources to conduct our business and remain compliant with our debt covenants throughout 2009 based upon our 2009 cash flow projections, anticipated capital requirements, the discretionary nature of our capital expenditures and available capacity under our bank credit facility. While current conditions in the financial markets are extremely difficult and illiquid, we have no current plans or requirements to raise capital through these markets. However, we cannot predict with any certainty the impact to our future business of any further disruption or deterioration in the financial markets. We will continue to closely monitor our liquidity and the credit markets and may choose to access them opportunistically should conditions and capital market liquidity improve.

We filed a shelf registration statement on Form S-3 with the SEC on November 26, 2008. The shelf provides for an aggregate of $500 million, through the sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow the Company to be proactive in its ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings, subject to market conditions. This shelf registration statement was declared effective by the SEC on January 30, 2009. There are no immediate plans to raise any funds and there is no assurance that we will be able to secure any such funds should the need arise.

See Item 7A, Quantitative and Qualitative Disclosure about Market Risk, for our discussion of credit risk.

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of December 31, 2008:

	Payments due by period				
Contractual Obligations and Contingent Commitments (1)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-Term Debt (2)	$ 394,867	$ -	$ 194,500	$ -	$ 200,367
Interest on long-term debt(2)	238,955	33,398	56,352	73,080	76,125
Operating leases	5,840	2,687	2,726	383	44
Asset retirement obligations	23,086	50	100	100	22,836
Rig commitments (3)	15,859	12,091	3,768	-	-
Capital expenditure commitments (4)	71,800	-	70,000	-	1,800
Derivative contracts (5)	10,486	4,766	(6,197)	11,917	-
Partnership derivative contracts (6)	13,944	3,808	10,136	-	-
Production tax liability	43,948	18,226	25,722	-	-
Firm transportation, sales and processing agreements (7)	217,495	8,391	37,490	50,333	121,281
Other liabilities (8)	8,380	446	1,240	1,240	5,454
Total	$ 1,044,660	$ 83,863	$ 395,837	$ 137,053	$ 427,907

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(1) Table does not include deferred income tax obligations to taxing authorities of $190.9 million and maximum annual repurchase obligations to investing partners of $15.9 million as of December 31, 2008 due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.
(2) Amounts presented for long term debt consist of amounts related to our 12% senior notes and our outstanding credit facility. The interest on long term debt includes $222.3 million payable to the holders of our 12% senior notes and $16.7 million related to our outstanding balance of $194.5 million on our credit facility as of December 31, 2008, based on an imputed interest rate of 4.65%.
(3) Drilling rig commitments in the above table reflect our maximum obligation and does not include future adjustments to daily rates as provided for in the agreements as such increases are not predictable and are only included in the above obligation table upon notification to us by the contractor of an increase in the rate. Further, our rig commitment above includes $5.1 million related to a rig sublet to a third party and remains our obligation should the third party default on terms of the sublet agreement.
(4) Primarily represents our capital expenditure commitment related to certain drilling and development agreements. See Note 8, Commitments and Contingencies, to our accompanying consolidated financial statements. These amounts do not include advances for future drilling contracts totaling $1.7 million at December 31, 2008.
(5) Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of $1.6 million as of December 31, 2008.
(6) Represents our affiliated partnerships' share of the fair value of our gross derivative assets at December 31, 2008.
(7) Represents our gross commitment, including amounts for volumes transported or sold on behalf of our affiliated partnerships and other working interest owners. We will recognize in our financial statements our proportionate share based on our working and net revenue interest.
(8) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

As managing general partner of 33 partnerships (see Item 1. Business – Drilling and Development Conducted for Company Sponsored Partnerships), we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings, see Note –8, Commitments and Contingencies – Litigation, and Note 17, Subsequent Events, to our accompanying consolidated financial statements included in this report. From time to time we are a party to various other legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse affect on our business, financial condition, results of operations, or liquidity.

Critical Accounting Policies and Estimates

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

Revenue Recognition

Oil and natural gas sales. Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered to a purchaser, collection of revenue from the sale is reasonably assured and the sales price is determinable. 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 short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

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

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We currently use the "net-back" method of accounting for transportation arrangements of natural gas sales. We sell gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by our customers and reflected in the wellhead price.

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

Oil and gas well drilling operations. Our drilling segment recognizes revenue from drilling contracts with sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. We utilize this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. We have offered our drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships and, consequently, different revenue reporting policies pursuant to Emerging Issues Task Force, or EITF, Issue No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent.

The first cost-plus drilling service arrangement was entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Due to the fixed-fee-percentage nature of our revenues from these services, we have determined that, in substance, we are acting as an agent, without risk of loss during the performance of the drilling activities. Accordingly, our services provided under the cost-plus drilling agreements are reported on a net basis. We entered into our second and third cost-plus drilling arrangements in September 2006 and August 2007 and commenced drilling immediately. Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are generally completed within nine to twelve months after the commencement of drilling. We provide geological, engineering, and drilling supervision on the drilling and completion process and use subcontractors to perform drilling and completion services at a fixed footage-based rate and accordingly have the risk of loss in performing services under these arrangements. Accordingly, we report revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that the estimated total costs exceed the estimated total contract revenue. At December 31, 2007, we had recorded a loss contract reserve of $0.2 million. There was no loss contract reserve as of December 31, 2008.

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

Fair Value of Financial Instruments

We adopted the provisions of Statement of SFAS No. 157, Fair Value Measurements, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and nonfinancial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances. In February 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FAS No. 157-2, Effective Date of FASB Statement No. 157, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Nonfinancial assets and liabilities for which we have not applied the provisions of SFAS No. 157 include those initially measured at fair value, including our asset retirement.

Derivative Financial Instruments.

We use derivative instruments to manage our commodity and financial market risks. We currently do not use hedge accounting treatment for our derivatives. Derivatives are reported on our accompanying consolidated balance sheets at fair value on a gross asset and liability basis. Changes in fair value of derivatives are recorded in oil and gas price risk management, net, in our accompanying consolidated statements of income.

SFAS No. 157 establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Instruments included in Level 1 consist of our commodity derivatives for New York Mercantile Exchange ("NYMEX")-based natural gas swaps.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments included in Level 3 consist of our commodity derivatives for Colorado Interstate Gas ("CIG") and Panhandle Eastern Pipeline ("PEPL")-based natural gas swaps, oil swaps, natural gas basis protection swaps, oil and natural gas options, and physical sales and purchases.

We measure fair value of our derivatives based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to our nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use two investment grade financial institutions as our counterparties to our derivative contracts. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2008, no valuation allowance was recorded. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value. We estimated the gross net fair value of our commodity based derivatives as of December 31, 2008, to be $153.5 million.

Non-Derivative Financial Assets and Liabilities.

The carrying values of the financial instruments comprising cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

The portion of our long-term debt related to our credit facility, approximates fair value due to the variable nature of its related interest rate. We estimate the fair value of the portion of our long-term debt related to our senior notes to be approximately $127 million or approximately 62.5% of par value as of December 31, 2008. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders participating in the trading of the securities.

Oil and Gas Properties

We account for our oil and gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and development dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing oil and natural gas reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved oil and gas reserves.

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Our estimates of proved reserves are based on quantities of oil and natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. Annually, we engage independent petroleum engineers to prepare a reserve and economic evaluation of all our properties on a well-by-well basis as of December 31. Additionally, we adjust our oil and gas reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have an effect on our net income.

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify our completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are expensed to exploration costs. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the well is classified as “suspended well costs” until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded. At December 31, 2008 and 2007, suspended well costs included in oil and gas properties on our accompanying consolidated financial statements was $1.2 million and $2.3 million, respectively.

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

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we assess our oil and gas properties for possible impairment 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 we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of oil and natural gas. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future net cash flows and an impairment of our oil and gas properties. Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Deferred Income Tax Asset Valuation Allowance

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

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

Accounting for Acquisitions Using Purchase Accounting

We account for acquisitions utilizing the purchase method as prescribed by SFAS No. 141, Business Combinations. Pursuant to purchase method accounting, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on appraisals, discounted cash flows, quoted market prices and estimates by management. In addition, when appropriate, we review comparable purchases and sales of oil and gas properties within the same regions, and use that data as a basis for fair market value; for example, the amount a willing buyer and seller would enter into an exchange for such properties.

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In estimating the fair values of assets acquired and liabilities assumed we made various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped and unproved oil and gas properties. To estimate the fair values of these properties, we prepared estimates of oil and gas reserves. We estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable and possible reserves were reduced by additional risk-weighting factors.

Deferred taxes must be recorded for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Recent Accounting Standards

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

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

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and restricted cash and the interest we pay on borrowings under our bank credit facility. Our 12% senior notes are fixed rate and, therefore, do not expose us to the cash flow loss due to changes in market interest rate. However, changes in interest rates do affect the fair value of our senior notes.

Our interest-bearing cash and cash equivalents include our money market accounts, short-term certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of December 31, 2008, was $78.8 million with an average annual interest rate of 1.8%.

Based on a sensitivity analysis of the credit facility borrowings as of December 31, 2008, it was estimated that if market interest rates were to average 1% higher (lower) in 2009 than in 2008, our interest expense, net of tax, would increase (decrease) by approximately $1.3 million.

Commodity Price Risk

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, Critical Accounting Policies and Estimates-Accounting for Derivatives Contracts at Fair Value, for further discussion of the accounting for derivative contracts.

We are exposed to the effect of market fluctuations in the prices of oil and natural gas as they relate to our oil and natural gas sales and marketing activities. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivatives. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe these valuation methods are appropriate and consistent with those used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Economic Hedging Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative contracts. As of December 31, 2008, our oil and natural gas derivative instruments consisted of (i) NYMEX-based natural gas contracts for Appalachian and Michigan production, (ii) PEPL-based contracts for NECO production, (iii) CIG-based contracts for other Colorado production and (iv) NYMEX-based crude oil contracts for our Colorado oil production.

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- For swap instruments, we receive a fixed price for the derivative contract and pay a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price is between the call and the put strike price, no payments are due from either party.

With regard to our natural gas marketing activities, we enter into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market. We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

The following table presents monthly average NYMEX and CIG closing prices for oil and natural gas in 2008 and 2007, as well as average sales prices we realized for the respective commodity.

	Year Ended December 31,	
	2008	2007
Average Index Closing Price		
Natural Gas (per MMbtu)		
CIG	$ 6.22	$ 3.97
NYMEX	9.04	6.89
Oil (per Barrel)		
NYMEX	104.42	69.79
Average Sales Price		
Natural Gas	6.98	5.33
Oil	89.77	60.65

Based on a sensitivity analysis as of December 31, 2008, it was estimated that a 10% increase in oil and natural gas prices, inclusive of basis, over the entire period for which we have derivatives currently in place would have resulted in an increase in fair value of $13.7 million and a 10% decrease in oil and natural gas prices would have resulted in an increase in fair value of $49.4 million.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Results of Operations, Oil and Gas Price Risk Management, Net and Natural Gas Marketing Activities, for a detailed discussion of the our open derivative positions related to our oil and gas sales activities and our natural gas marketing activities. See Note 3, Derivative Financial Instruments, to our accompanying consolidated financial statements included in this report for a summary of our open derivative positions as of December 31, 2008.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We have had no counterparty default losses.

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Our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries related to our gas marketing group. We monitor their creditworthiness through credit reports and rating agency reports.

Our commodity-based derivative contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. These contracts consist of fixed price swaps, basis swaps and collars. We primarily use two investment grade financial institutions as our counterparties to our derivative contracts who are also major lenders in our credit facility arrangement. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2008, no valuation allowance was recorded.

The recent disruption in the credit market has had a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance in these uncertain times.

Disclosure of Limitations

Because the information above included only those exposures that exist at December 31, 2008, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our hedging strategies at the time, and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Index to financial statements.

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

As reported on Form 8-K filed with the SEC on May 31, 2007, and incorporated herein by reference, the Audit Committee of our Board of Directors recommended, and the Board of Directors ratified, the dismissal of KPMG LLP as our principal accountants on May 24, 2007.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2008, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2008, to ensure that the information required to be disclosed by the Company in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC rules and forms, and that the information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2008, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

See Remediation of Material Weaknesses in Internal Control below for a discussion of changes in our internal control over financial reporting that occurred throughout 2008.

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Remediation of Material Weaknesses in Internal Control

We, with oversight from the Audit Committee of our Board of Directors, have been addressing the material weaknesses disclosed in our 2007 Form 10-K and Item 4 of our subsequently filed Form 10-Q for each of the quarterly periods in the nine-month period ended September 30, 2008. We have concluded, based on our assessment, that, through the implementation of the changes in internal controls over financial reporting described below, we have remediated these previously reported material weaknesses as of December 31, 2008. Management's annual report on internal control over financial reporting and the audit report on our internal control over financial reporting of our independent registered public accounting firm are included in response to Item 8 of this report on pages F-2 and F-3 included herein.

The remediation initiatives that were undertaken during 2008 include:

- In the first quarter of 2008, we implemented the general ledger, accounts receivable, and joint interest billing modules as part of a new broader financial reporting system. We have taken the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps included providing training related to business process changes and the financial reporting system software to individuals using the financial reporting system to carry out their job responsibilities as well as those who rely on the financial information. The implementation of the financial reporting system strengthened the overall internal controls due to enhanced automation and integration of related processes. The design and documentation of internal control process and procedures relating to the new system has been modified to supplement and complement existing internal controls over financial reporting.

- In the third quarter of 2008, we implemented controls over key financial statement spreadsheets that support all significant balance sheet and income statement accounts. Specifically, we enhanced the spreadsheet policy to provide additional clarification and guidance with regard to risk assessment and enforced controls over: 1) the security and integrity of the data used in the various spreadsheets, 2) access to the spreadsheets, 3) changes to spreadsheet functionality and the related approval process and documentation and 4) increased managements review of the spreadsheets.

- In the third quarter of 2008, key personnel attended an accredited derivative training course and a desktop procedure was implemented to ensure the completeness and accuracy over derivative activities, which supplemented the key controls that previously existed in the process.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information called for by Item 10 is incorporated by reference from information under the captions entitled Corporate Governance, Section 16(a) Beneficial Ownership Reporting Compliance, Election of Directors and Executive Compensation and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by Item 11 is incorporated by reference from information under the caption entitled Executive Compensation and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

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

The information called for by Item 12 is incorporated by reference from information under the caption entitled Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information called for by Item 13 is incorporated by reference from information under the captions entitled Certain Relationships and Related Transactions and Director Independence in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information called for by Item 14 is incorporated by reference from information under caption entitled Principal Accountant Fees and Services and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements:
See Index to Financial Statements and Schedules on page F-1.
(2) Financial Statement Schedules:
See Index to Financial Statements and Schedules on page F-1.
Schedules and Financial Statements Omitted
All other financial statement schedules are omitted because they are not required, inapplicable, or the information is included in the Financial Statements or Notes thereto.
(3) Exhibits:
See Exhibits Index on page 56.

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SIGNATURES

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

PETROLEUM DEVELOPMENT CORPORATION

By /s/ Richard W. McCullough
Richard W. McCullough,
Chairman, Chief Executive Officer, and President

By /s/ Gysle R. Shellum
Gysle R. Shellum,
Chief Financial Officer

February 26, 2009

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

Signature	Title	Date
/s/ Richard W. McCullough Richard W. McCullough	Chairman, Chief Executive Officer, and President (principal executive officer)	February 26, 2009
/s/ Gysle R. Shellum Gysle R. Shellum	Chief Financial Officer (principal financial officer)	February 26, 2009
/s/ Darwin L. Stump Darwin L. Stump	Chief Accounting Officer (principal accounting officer)	February 26, 2009
/s/ Daniel W. Amidon Daniel W. Amidon	General Counsel, Corporate Secretary	February 26, 2009
/s/ Steven R. Williams Steven R. Williams	Director	February 26, 2009
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	February 26, 2009
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	February 26, 2009
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	February 26, 2009
/s/ David C. Parke	Director	February 26, 2009

David C. Parke

/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	February 26, 2009
/s/ Joseph E. Casabona Joseph E. Casabona	Director	February 26, 2009
/s/ Larry F. Mazza Larry F. Mazza	Director	February 26, 2009

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

Bcf - One billion cubic feet.

Bcfe - One billion cubic feet of natural gas equivalent.

CIG - Colorado Interstate Gas.

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

DD&A - Refers to depreciation, depletion and amortization of our property and equipment.

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

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

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

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

Gross acres or wells - Refers to the total acres or wells in which we have a working interest.

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

MBbls - One thousand barrels.

Mcf - One thousand cubic feet.

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

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

MMcf - One million cubic feet.

MMcfe - One million cubic feet of natural gas equivalent.

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

Net production - Oil and gas production that we own, less royalties and production due others.

NYMEX - New York Mercantile Exchange.

Oil - Crude oil or condensate.

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

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PEPL - Panhandle Eastern Pipeline.

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

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

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

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

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

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

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

Refrac, or refracture – A refrac is when we stimulate the present producing zone of a well to increase production, using hydraulic, acid, gravel, etc. fracture techniques.

Reserve replacement - Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values used for reserve additions are derived directly from the proved reserves table located in Note 18, Supplemental Oil and Gas information, to our consolidated financial statements included in this report. We use the reserve replacement ratio as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

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

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

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

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

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

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Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1	Second Amended and Restated Certificate of Incorporation of Petroleum Development Corporation.	8-K	000-07246	3.1	07/23/2008	
3.2	Bylaws of Petroleum Development Corporation, amended and restated, effective October 11, 2007.	8-K	000-07246	3.2	10/17/2007	
4.1	Rights Agreement by and between Petroleum Development Corporation and Transfer Online, Inc., as Rights Agent, dated as of September 11, 2007, including the forms of Rights Certificates and Summary of Stockholder Rights Plan attached thereto as Exhibits A and B.	8-K	000-07246	4.1	09/14/2007	
4.2	Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and The Bank of New York.	8-K	000-07246	4.1	02/12/2008	
4.3	First Supplemental Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and the Bank of New York.	8-K	000-07246	4.2	02/12/2008	
4.4	Form of 12% Senior Note due 2018.	8-K	000-07246	4.3	02/12/2008	
10.1	Purchase Agreement dated as of February 1, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	02/07/2008	
10.2	Registration Rights Agreement dated as of February 8, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	02/12/2008	
10.3	Amended and Restated Credit Agreement dated as of November 4, 2005, Petroleum Development Corporation, as borrower and JPMorgan Chase Bank, N.A and BNP Paribas, as lenders.	8-K	000-07246	10.1	11/04/2005	

10.4	First Amendment to Amended and Restated Credit Agreement, dated as of August 9, 2007, by an among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., BNP Paribas and Wachovia Bank, N.A.	8-K	000-07246	10.1	08/15/2007
10.5	Second Amendment to Amended and Restated Credit Agreement, dated as of October 16, 2007, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., BNP Paribas, Wachovia Bank, N.A., Guaranty Bank, FSB, Bank of Oklahoma and Morgan Stanley Bank.	8-K	000-07246	10.1	10/22/2007
10.6	Third Amendment to Amended and Restated Credit Agreement dated as of July 15, 2008, by and among Petroleum Development Corporation, certain of its subsidiaries, JP Morgan Chase Bank, N.A., BNP Paribas and various other banks.	8-K	000-07246	10.1	07/21/2008
10.7	Fourth Amendment to Amended and Restated Credit Agreement dated as of July 18, 2008, by and among the Company, certain of its subsidiaries, JP Morgan Chase Bank, N.A., BNP Paribas and various other banks.	8-K	000-07246	10.2	07/21/2008
10.8	Fifth Amendment to Amended and Restated Credit Agreement dated as of November 12, 2008, by and among the Company, certain of its subsidiaries, JP Morgan Chase Bank, N.A., various other banks.	8-K	000-07246	10.1	11/19/2008

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.9*	Employment Agreement with Richard W. McCullough, Chief Executive Officer, dated as of December 31, 2008.					X
10.10*	Employment Agreement with Eric R. Stearns, Executive Vice President, dated as of December 31, 2008.					X
10.11*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of December 31, 2008.					X
10.12*	Employment Agreement with Barton R. Brookman, Jr., Senior Vice President of Exploration and Production, dated as of December 31, 2008.					X
10.13*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of December 31, 2008.					X
10.14*	Employment Agreement with Darwin L. Stump, Chief Accounting Officer, dated as of December 31, 2008.					X
10.15*	2008 Short-Term Incentive Compensation Terms for Executive Officers.	8-K	000-07246		03/28/2008	
10.16*	2008 Long-Term Incentive Program (as amended for 2008) for Executive Officers.	8-K	000-07246	10.1	03/13/2008	
10.17*	Non-Employee Director Compensation for the 2008-2009 Term.	8-K	000-07246		03/13/2008	
10.18*	2008 Base Salary and Short-Term Incentive Cash Bonus Program for Executive Officers.	8-K	000-07246		02/22/2008	
10.19*	2007 Long-Term Incentive Program for Executive Officers.	8-K	000-07246	10.1	04/13/2007	
10.20*	2006 Long-Term Equity Compensation Grants to Executive Officers.	8-K	000-07246		04/10/2007	
10.21*	Agreement with Steven R. Williams, Director.	10-Q	000-07246	10.3	11/06/2008	

10.22*	Separation Agreement with Thomas E. Riley, former President.					X
10.23*	Indemnification Agreement with Directors and Officers.	10-Q	000-07246	10.1	08/09/2007	
10.24*	The Petroleum Development Corporation 401(k) & Profit Sharing Plan.	S-8	333-137836	4.1	10/05/2006	
10.25*	2005 Non-Employee Director Restricted Stock Plan amended and restated as of March 8, 2008.	10-Q	000-07246	10.6	11/06/2008	
10.26*	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008.					X
10.27*	Non-Employee Director Deferred Compensation Plan.	S-8	333-118222	99.1	08/13/2004	
10.28*	1999 Incentive Stock Option and Non-Qualified Stock Plan.	S-8	333-111825	99.1	01/09/2004	
14.1	Code of Business Conduct and Ethics.					X
21.1	Subsidiaries.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of KPMG LLP.					X
23.3	Consent of Wright & Company, Inc., Petroleum Consultants.					X
23.4	Consent of Ryder Scott Company, L.P., Petroleum Consultants.					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					X

*Management contract or compensatory plan or arrangement.

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PETROLEUM DEVELOPMENT CORPORATION

Index to Consolidated Financial Statements and Financial Statement Schedule

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PETROLEUM DEVELOPMENT CORPORATION

Management's Report on Internal Control Over Financial Reporting

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

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008, based upon the criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2008.

The effectiveness of Petroleum Development Corporation's internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

PETROLEUM DEVELOPMENT CORPORATION

/s/ Richard W. McCullough
Richard W. McCullough
Chairman and Chief Executive Officer

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer

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PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders
of Petroleum Development Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Petroleum Development Corporation and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the 2008 and 2007 information in the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the 2008 and 2007 information in the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 5 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions in 2007.

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

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

/s/ PricewaterhouseCoopers LLP
Pittsburgh, Pennsylvania
February 26, 2009

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PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Petroleum Development Corporation:

We have audited the accompanying consolidated statements of operations, shareholders' equity, and cash flows of Petroleum Development Corporation and subsidiaries for the year ended December 31, 2006. In connection with our audit of these consolidated financial statements, we also have audited the related financial statement schedule. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

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

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

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

KPMG LLP

Pittsburgh, Pennsylvania
May 22, 2007

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PETROLEUM DEVELOPMENT CORPORATION
Consolidated Balance Sheets
(in thousands, except share and per share data)

December 31,	2008	2007
Assets		
Current assets:		
Cash and cash equivalents	$ 50,950	$ 84,751
Restricted cash - current	19,030	14,773
Accounts receivable, net	69,688	60,024
Accounts receivable - affiliates	16,742	11,537
Fair value of derivatives - current	116,881	4,817
Prepaid expenses and other current assets	19,146	15,891
Total current assets	292,437	191,793
Properties and equipment, net	1,033,078	845,864
Other assets	77,189	12,822
Total Assets	$ 1,402,704	$ 1,050,479
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 90,532	$ 88,502
Accounts payable - affiliates	40,540	3,828
Production tax liability	18,226	21,330
Federal and state income taxes payable	1,591	901
Fair value of derivatives	4,766	6,291
Advances for future drilling contracts	1,675	68,417
Funds held for distribution	50,361	39,823
Net deferred income taxes - current	28,355	-
Other accrued expenses	25,125	12,913
Total current liabilities	261,171	242,005
Long-term debt	394,867	235,000
Net deferred income taxes - non current	162,593	136,490
Other liabilities	71,798	40,699
Total liabilities	890,429	654,194
Commitments and contingent liabilities		
Minority interest in consolidated limited liability company	694	759
Shareholders' equity:		
Preferred shares, par value $.01 per share; authorized 50,000,000 shares; issued: none	-	-
Common shares, par value $.01 per share; authorized 100,000,000 shares; issued: 14,871,870 in 2008 and 14,907,679 in 2007	149	149
Additional paid-in capital	5,818	2,559
Retained earnings	505,906	393,044
Treasury shares, at cost: 7,066 shares in 2008 and 5,894 in 2007	(292)	(226)
Total shareholders' equity	511,581	395,526
Total Liabilities and Shareholders' Equity	$ 1,402,704	$ 1,050,479

See accompanying Notes to Consolidated Financial Statements.

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

Year Ended December 31,	2008	2007	2006
Revenues:			
Oil and gas sales	$ 321,877	$ 175,187	$ 115,189
Sales from natural gas marketing activities	140,263	103,624	131,325
Oil and gas well drilling	7,615	12,154	17,917
Well operations and pipeline income	11,474	9,342	10,704
Oil and gas price risk management gain, net	127,838	2,756	9,147
Other	293	2,172	2,221
Total revenues	609,360	305,235	286,503
Costs and expenses:			
Oil and gas production and well operations cost	78,209	49,264	29,021
Cost of natural gas marketing activities	139,234	100,584	130,150
Cost of oil and gas well drilling	2,213	2,508	12,617
Exploration expense	45,105	23,551	8,131
General and administrative expense	37,715	30,968	19,047
Depreciation, depletion, and amortization	104,575	70,844	33,735
Total costs and expenses	407,051	277,719	232,701
Gain on sale of leaseholds	-	33,291	328,000
Income from operations	202,309	60,807	381,802
Interest income	591	2,662	8,050
Interest expense	(28,132)	(9,279)	(2,443)
Income before income taxes	174,768	54,190	387,409
Provision for income taxes	61,459	20,981	149,637
Net income	$ 113,309	$ 33,209	$ 237,772
Earnings per common share:			
Basic	$ 7.69	$ 2.25	$ 15.18
Diluted	$ 7.63	$ 2.24	$ 15.11
Weighted average common and common equivalent shares outstanding:			
Basic	14,736	14,744	15,660
Diluted	14,848	14,841	15,741

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION
Consolidated Statements of Shareholders' Equity
(in thousands, except share and per share data)

Year Ended December 31,	2008	2007	2006
Common stock, par value $.01 per share - shares issued:			
Shares at beginning of year	14,907,679	14,834,871	16,281,923
Adjust prior conversion of predecessor shares	100	-	59,546
Exercise of stock options	25,699	38,000	8,000
Issuance of stock awards, net of forfeitures	21,863	46,828	112,902
Retirement of treasury shares	(83,471)	(12,020)	(1,627,500)
Shares at end of year	14,871,870	14,907,679	14,834,871
Treasury stock:			
Shares at beginning of year	(5,894)	(4,706)	-
Purchase of treasury shares	(83,471)	(12,020)	(1,627,500)
Retirement of treasury shares	83,471	12,020	1,627,500
Non-employee directors' deferred compensation plan	(1,172)	(1,188)	(4,706)
Shares at end of year	(7,066)	(5,894)	(4,706)
Common shares outstanding	14,864,804	14,901,785	14,830,165
Common stock, $.01 par:			
Balance at beginning of year	$ 149	$ 148	$ 163
Exercise of stock options	-	-	-
Issuance of stock awards, net of forfeitures	-	1	1
Retirement of treasury shares	-	-	(16)
Balance at end of year	149	149	148
Additional paid-in capital:			
Balance at beginning of year	2,559	64	30,423
Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)	-	-	(825)
Exercise of stock options	627	183	31
Issuance of stock awards, net of forfeitures	-	(1)	(1)
Stock based compensation expense	6,702	2,286	1,516
Retirement of treasury shares	(5,101)	(646)	(31,150)
Excess tax benefit of stock based compensation	1,031	673	70
Balance at end of year	5,818	2,559	64
Retained earnings:			
Balance at beginning of year	393,044	360,102	158,504
Cumulative effect adjustment for the adoption of SAB 108, net of tax	-	-	(1,021)
FIN 48 adoption	-	(267)	-
Retirement of treasury shares	(447)	-	(35,153)
Net income	113,309	33,209	237,772
Balance at end of year	505,906	393,044	360,102
Unamortized stock award			
Balance at beginning of year	-	-	(825)
Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)	-	-	825
Balance at end of year	-	-	-
Treasury stock, at cost:			

Balance at beginning of year		(226)		(170)		-
Purchase of treasury shares		(5,549)		(646)		(66,319)
Retirement of treasury shares		5,549		646		66,319
Non-employee directors' deferred compensation plan		(66)		(56)		(170)
Balance at end of year		(292)		(226)		(170)
Total shareholders' equity	$	511,581	$	395,526	$	360,144

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION
Consolidated Statements of Cash Flows
(in thousands)

Year Ended December 31,	2008	2007	2006
Cash flows from operating activities:			
Net income	$ 113,309	$ 33,209	$ 237,772
Adjustments to net income to reconcile to net cash provided by operating activities:			
Deferred income taxes	59,079	12,201	86,431
Depreciation, depletion and amortization	104,575	70,844	33,735
Allowance for doubtful accounts	180	50	7
Amortization of debt issuance costs	1,344	394	-
Impairment of oil and gas properties	22,091	1,485	1,519
Accretion of asset retirement obligation	1,230	999	515
Exploratory dry hole costs	6,504	1,775	1,790
Loss (gain) from sale of leaseholds/assets	19	(33,322)	(327,991)
Expired and abandoned leases	3,633	1,786	2,169
Stock based compensation	6,702	2,286	1,516
Unrealized (gains) losses on derivative transactions	(117,536)	4,642	(7,620)
Excess tax benefits from stock-based compensation	(1,031)	(673)	(70)
Changes in current assets and liabilities:			
(Increase) decrease in restricted cash	(4,257)	(14,254)	982
Increase in accounts receivable	(9,844)	(16,506)	(9,942)
Increase in accounts receivable - affiliates	(7,631)	(2,302)	(194)
(Increase) decrease in inventories	(2,062)	1,285	1,987
(Increase) decrease in other current assets	(5,793)	4,839	(2,106)
Increase (decrease) in production tax liability	9,857	10,802	(261)
Increase (decrease) in accounts payable and accrued expenses	2,790	(10,869)	13,010
Increase (decrease) in accounts payable - affiliates	10,282	(3,099)	6,116
(Decrease) increase in advances for future drilling contracts	(66,742)	13,645	4,773
Increase (decrease) in federal and state income taxes payable	1,721	(27,124)	19,950
Increase in funds held for future distribution	10,538	7,488	(575)
Other	143	723	3,877
Net cash provided by operating activities	139,101	60,304	67,390
Cash flows from investing activities:			
Capital expenditures	(323,153)	(238,988)	(146,945)
Acquisition of oil and gas properties, net of cash acquired	-	(255,661)	(18,512)
Investment in drilling partnerships	-	-	(7,151)
(Increase) decrease in restricted/designated cash	(874)	191,156	(192,416)
Proceeds from sale of leases to partnerships	448	1,371	1,798
Proceeds from sale of leaseholds/assets	538	34,701	353,600
Net cash used in investing activities	(323,041)	(267,421)	(9,626)
Cash flows from financing activities:			
Proceeds from credit facility	419,000	352,000	302,000
Proceeds from senior notes	200,101	-	-
Proceeds from short-term debt	-	-	20,000
Payment of credit facility	(459,500)	(254,000)	(209,000)
Payment of debt issuance costs	(5,571)	(1,468)	(160)

Proceeds from exercise of stock options	627	183	31
Excess tax benefits from stock-based compensation	1,031	673	70
Minority interest investment	-	800	-
Purchase of treasury stock	(5,549)	(646)	(66,489)
Net cash provided by financing activities	150,139	97,542	46,452
Net (decrease) increase in cash and cash equivalents	(33,801)	(109,575)	104,216
Cash and cash equivalents, beginning of year	84,751	194,326	90,110
Cash and cash equivalents, end of year	$ 50,950	$ 84,751	$ 194,326
Supplemental cash flow information:			
Cash payments for:			
Interest, net of capitalized interest	$ 19,200	$ 9,535	$ 1,376
Income taxes, net of refunds	(530)	43,785	46,735
Non-cash investing activities:			
Change in deferred tax liability resulting from reallocation of acquisition purchase price	-	4,188	-
Change in accounts payable - affiliates related to acquisition of partnerships	-	668	-
Change in accounts payable related to purchases of properties and equipment	8,197	32,820	1,800
Change in accounts payable - affiliates related to investment in drilling partnership	-	18,712	(7,151)
Change in asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	1,153	7,850	3,164

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Petroleum Development Corporation ("PDC," "we," "us" or "the Company") is an independent energy company engaged primarily in the drilling and development, production and marketing of natural gas and oil. Since we began oil and gas operations in 1969, we have grown primarily through drilling and development activities, the acquisition of producing natural gas and oil wells and the expansion of our natural gas marketing activities. As of December 31, 2008, we operate approximately 4,712 wells located in the Appalachian Basin, Michigan Basin, and the Rocky Mountain Region. Our oil and natural gas wells are located in West Virginia, Tennessee, Pennsylvania, Michigan, North Dakota, Colorado, Kansas, Texas and Wyoming. We separate our operations into four business segments: oil and gas sales, natural gas marketing activities, well operations and pipeline income and oil and gas well drilling operations. See Note 16, Business Segments.

Principles of Consolidation

The consolidated financial statements of PDC include the accounts of our wholly-owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. We account for our investment in interests in oil and gas limited partnerships under the proportionate consolidation method. Under this method, our consolidated financial statements include our investments in the partnerships recorded by our working interest in each well thereby accumulating our pro rata share of assets, liabilities and revenues and expenses respectively of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships is eliminated.

Use of Estimates

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

Cash Equivalents

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

Restricted Cash

Included in our restricted cash – current as of December 31, 2007, along with interest earned of $0.4 million, is an escrow account funded in June 2007 in the amount of $14.1 million, representing amounts due to the limited partners of our sponsored drilling partnerships as a result of our over withholding estimated production taxes in years prior to 2007. In October 2008, as part of a pre-filing agreement, we paid the Internal Revenue Service on behalf of the limited partners an estimated tax payment of $4.2 million. As of December 31, 2008, we had reflected in restricted cash - current $10.6 million, including additional interest of $0.3 million earned in 2008.

Pursuant to a preliminary court approved litigation settlement agreement reached in October 2008, we funded an escrow account in November 2008 in the amount of $8.2 million, of which $5.8 million represented the Company's share of the settlement and the remainder being that of the affiliated partnerships for which the Company serves as the managing general partner. As of December 31, 2008, restricted cash – current includes $8.2 million related to this escrow account. Further, our balance sheet includes a related accounts receivable from our affiliated partnerships of $2.4 million.

We are required by a counterparty to maintain a margin deposit for outstanding derivative contracts. As of December 31, 2007, cash in the amount of $0.3 million was on deposit and reflected in our consolidated balance sheets as restricted cash - current. As of December 31, 2008, the margin deposit requirement was insignificant.

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We are required by various government agencies or joint venture agreements to maintain a bond or cash account for the plugging and abandonment of wells. As of December 31, 2008 and 2007, we had bonds in the form of certificates of deposit for plugging and abandonment of wells totaling $2.2 million and $1.3 million, respectively, which are reflected in other assets.

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil and natural gas and third parties and affiliated partnerships for well pipeline operating services. Inherent to our industry is the concentration of oil and natural gas sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions.

We provide an allowance for doubtful accounts equal to the estimated uncollectible amounts. In making our estimate, we consider our historical write-offs, relationships and overall creditworthiness of our customers, additional consideration is given to well production data for receivables related to well operations. It is reasonably possible that our estimate of uncollectible amounts will change periodically. Accounts receivable are presented on our consolidated balance sheets net of allowance for doubtful accounts of $0.5 million and $0.4 million at December 31, 2008 and 2007, respectively.

Inventories

Materials, supplies and commodity inventories are stated at the lower of average cost or market and removed at carrying value. Inventory of $4.3 million and $2.2 million as of December 31, 2008 and 2007, respectively, is included in prepaid expenses and other current assets on our consolidated balance sheets.

Derivative Financial Instruments

We account for derivative financial instruments in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, as amended.

During 2008, 2007 and 2006, none of our derivative instruments qualified for use of hedge accounting under the terms of SFAS No. 133. Accordingly, we recognize all derivative instruments as either assets or liabilities on our consolidated balance sheets at fair value, and changes in the derivatives' fair values are recorded on a net basis in our consolidated statements of operations. Changes in the fair value of derivative instruments related to our oil and gas sales activities are recorded in oil and gas price risk management, net and changes in fair value of derivatives related to our natural gas marketing activities are recorded in sales from and cost of natural gas marketing activities.

We record on our consolidated balance sheets the fair value of derivative instruments entered into by us and allocated to our affiliated partnerships, recording an offsetting receivable from or payable to those partnerships.

See Note 2, Fair Value of Financial Instruments, and Note 3, Derivative Financial Instruments, for a discussion of our derivative fair value measurements and a summary fair value table of our open positions as of December 31, 2008 and 2007, respectively.

Properties and Equipment

Oil and Gas Properties.

We account for our oil and gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and development dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing oil and natural gas reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved oil and gas reserves.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Our estimates of proved reserves are based on quantities of oil and natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. Annually, we engage independent petroleum engineers to prepare a reserve and economic evaluation of all our properties on a well-by-well basis as of December 31. Additionally, we adjust our oil and gas reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. Because estimates of reserves significantly affect our depreciation, depletion and amortization (“DD&A”) expense, a change in our estimated reserves could have an effect on our net income.

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify our completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are expensed to exploration costs. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are classified as “suspended well costs” until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the same well is removed from the suspended well status and the proper accounting treatment is recorded. At December 31, 2008, suspended well costs included in oil and gas properties on our consolidated balance sheet were $1.2 million. See Note 4, Properties and Equipment.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved oil and gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to exploratory expense. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms. Impairment costs are recorded in the statements of operations as a component of exploration expense and were as follows for each of the periods indicated:

	2008	2007	2006
		(in thousands)	
Individually significant unproved properties (1)	$ 9,165	$ 1,484	$ 473
	3,633	1,786	157

Insignificant unproved properties						
Total	$	12,798	$	3,270	$	630

(1) 2007 includes liquidated damages of $1.1 million related to the abandonment of an exploration agreement with an unaffiliated party.

The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we assess our oil and gas properties for possible impairment quarterly 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 we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of oil and natural gas. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future net cash flows and an impairment of our oil and gas properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows. We recognized impairment losses on proved oil and gas properties of $12.8 million in 2008, consisting of $7.5 million related to our properties in the Fort Worth Basin, $3 million in our Bakken Field in North Dakota and $2.3 million in our Nesson Field also in North Dakota. In 2006, we recorded an impairment loss of $1.5 million in our Nesson Field. Impairment charges related to our oil and gas properties are included in our statements of operations as a component of exploration expense. No impairments related to proved oil and natural gas properties were recorded in 2007.

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

Other Property and Equipment.

The following table sets forth the estimated useful lives of our other property and equipment.

Pipelines and related facilities	10 - 17 years
Transportation and other equipment	3 - 20 years
Buildings	30 - 40 years

Pipelines, Transportation Equipment and Other Equipment. Pipelines, transportation equipment and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over the assets estimated useful lives. In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, long-lived assets, such as property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds our estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset. No impairments were recorded in 2008, 2007or 2006.

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

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

Total depreciation expense related to other property and equipment was $7.6 million, $4.3 million and $2 million in 2008, 2007 and 2006, respectively.

Capitalized Interest

Interest costs are capitalized as part of the historical cost of acquiring assets. Oil and gas investments in unproved properties and major development projects, on which DD&A expense is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready for service. Capitalized interest is calculated by multiplying our weighted-average interest rate on our debt outstanding by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is moved to the DD&A pool, the related capitalized interest is also transferred and is amortized over the useful life of the asset. Interest costs of $2.6 million, $3 million and $1.6 million were capitalized in 2008, 2007 and 2006, respectively.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Production Tax Liability

Production tax liability represents estimated taxes, primarily severance and property, to be paid to the states and counties in which we produce oil and gas. Our share of these taxes is expensed to oil and gas production and well operations cost.

Advances for Future Drilling Contracts

Advances for future drilling contracts represent funds received from our sponsored drilling partnerships for drilling activities which have not been completed, a portion of which will be recognized as revenue in accordance with our revenue recognition policies. The amount advanced and outstanding as of December 31, 2008, are primarily related to the drilling partnership sponsored in August 2007 and represents the remaining costs to finish the wells, primarily reclamation. No partnership was sponsored in 2008.

Income Taxes

We account for income taxes under the asset and liability method. We recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred tax assets will not be realized, we record a valuation allowance thereby reducing the deferred tax assets to what we consider realizable. No valuation allowance was recorded at December 31, 2008 or 2007.

Asset Retirement Obligations

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

Minority Interest in Consolidated Limited Liability Company

In May 2007, we contributed $0.8 million for a 50% interest in WWWV, LLC (“LLC”), a limited liability company for which we serve as the managing member. One-sixth of the entity is owned by a member of our Board of Directors, who paid the same unit price for his interest as was paid by us and unrelated third parties for such interests in the LLC. The LLC's only asset is an aircraft and the LLC was formed for the purpose of owning and operating the aircraft.

The minority interest portion of pre-tax expense incurred by and belonging to the minority interest holders of the consolidated limited liability company is not material and is included in our consolidated statement of operations as an offset to DD&A expense.

Retirement of Treasury Shares

We have historically retired all treasury share purchases, with the exception of shares purchased in accordance with our non-employee deferred compensation plan for non-employee directors, see Note 9, Common Stock. As treasury shares are retired, we charge any excess of cost over the par value entirely to additional paid-in-capital, to the extent we have amounts in paid-in-capital, with any remaining excess cost being charged to retained earnings.

Revenue Recognition

Oil and natural gas sales. Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered to a purchaser, collection of revenue from the sale is reasonably assured and the sales price is determinable. 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 short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

We currently use the "net-back" method of accounting for transportation arrangements of our natural gas sales. We sell gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by the customers and reflected in the wellhead price.

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

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

The first cost-plus drilling service arrangement was entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Due to the fixed-fee-percentage nature of our revenues from these services, we have determined that, in substance, we are acting as an agent, without risk of loss during the performance of the drilling activities. Accordingly, our services provided under the cost-plus drilling agreements are reported on a net basis. We entered into our second and third cost-plus drilling arrangements in September 2006 and August 2007 and commenced drilling immediately.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are generally completed within nine to twelve months after the commencement of drilling. We provide geological, engineering, and drilling supervision on the drilling and completion process and use subcontractors to perform drilling and completion services and accordingly we have the risk of loss in performing services under these arrangements. Accordingly, we report revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that the estimated total costs exceed the estimated total contract revenue. At December 31, 2007, included as a component of other current liabilities on the consolidated balance sheets, we had recorded a loss contract reserve of $0.2 million. No loss contract reserve was recorded as of December 31, 2008.

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment ("SFAS No. 123R"), to account for stock-based compensation. SFAS No. 123R eliminated the use of Accounting Principles Board Opinion ("APB") No. 25, Accounting for Stock Issued to Employees, and the intrinsic value method of accounting for equity compensation and requires us to recognize the cost of employee services received in exchange for awards of equity instruments based on fair value at the date of grant in our financial statements. We elected to use the modified prospective method for adoption, and accordingly, prior period financial statements have not been restated. For all unvested options and other equity based awards outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in the financial statements over the remaining requisite service period for each separately vesting portion. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in the financial statements on a straight-line basis over the vesting period for the entire award. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, such amounts are capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the appropriate cost and expense line item in the statement of operations. No amounts for stock-based compensation were capitalized in 2008, 2007 and 2006.

Earnings Per Share

Basic earnings per common share ("EPS") is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly computed except that the denominator includes the effect, using the treasury stock method, of our outstanding stock options, unamortized portion of restricted stock and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following is a reconciliation of the basic and diluted weighted-average shares outstanding for the years ended December 31:

	2008	2007	2006
	(in thousands, except per share data)		
Weighted average common shares outstanding - basic	14,736	14,744	15,660
Dilutive effect of share-based compensation: (1)			
Unamortized portion of restricted stock	71	44	22
Stock options	35	48	55
Non employee director deferred compensation	6	5	4
Weighted average common and common share equivalents outstanding - diluted	14,848	14,841	15,741
(1) Weighted average common share equivalents excluded from diluted earnings per share due to			

their anti-dilutive affect:

Unamortized portion of restricted stock	73	18	-
Stock options	-	-	24
Total anti-dilutive common share equivalents	73	18	24

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Recent Accounting Standards

Recently Adopted Accounting Standards

We adopted the provisions of Statement of SFAS No. 157, Fair Value Measurements, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and nonfinancial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances. In February 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FAS No. 157-2, Effective Date of FASB Statement No. 157, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Nonfinancial assets and liabilities for which we have not applied the provisions of SFAS No. 157 include those initially measured at fair value, including our asset retirement obligations. As of the adoption date, we have applied the provisions of SFAS No. 157 to our recurring measurements and the impact was not material to our underlying fair values and no amounts were recorded relative to the cumulative effect of a change in accounting. We are currently evaluating the potential effect that the nonfinancial assets and liabilities provisions of SFAS No. 157 will have on our financial statements when adopted in 2009. See Note 2, Fair Value of Financial Instruments.

In October 2008, the FASB issued FSP No. FAS 157-3, Determining the Fair Value of a Financial Asset in a Market That Is Not Active, which applies to financial assets within the scope of accounting pronouncements that require or permit fair value measurements in accordance with SFAS No. 157. This FSP clarifies the application of SFAS No. 157 in a market that is not active and defines additional key criteria in determining the fair value of a financial asset when the market for that financial asset is not active. FSP No. FAS 157-3 was effective upon issuance and did not have a material impact on our financial statements.

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

In April 2007, the FASB issued FSP No. FIN 39-1, Amendment of FASB Interpretation No. 39 ("FIN 39-1"), to amend certain portions of Interpretation 39. FIN 39-1 replaces the terms "conditional contracts" and "exchange contracts" in Interpretation 39 with the term "derivative instruments" as defined in Statement 133. FIN 39-1 also amends Interpretation 39 to allow for the offsetting of fair value amounts for the right to reclaim cash collateral or receivable, or the obligation to return cash collateral or payable, arising from the same master netting arrangement as the derivative instruments. FIN 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. The January 1, 2008, adoption of FSP FIN 39-1 had no impact on our financial statements.

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

In July 2006, the FASB issued FIN No. 48, Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109, which prescribes a comprehensive model for accounting for uncertainty in tax positions. FIN No. 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service (“IRS”), based on the technical merits of the position. We adopted the provisions of FIN No. 48 effective January 1, 2007. The cumulative effect of applying the provisions of FIN No. 48 has been accounted for as an adjustment to retained earnings in the first quarter of 2007. The adoption of FIN No. 48 resulted in a $0.3 million cumulative effect adjustment (see Note 5, Income Taxes, for further discussion).

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In May 2007, the FASB issued FASB Staff Position FIN No. 48-1, Definition of Settlement in FASB Interpretation No. 48 ("FIN No. 48-1"). FIN No. 48-1 amends FIN No. 48 to provide guidance on how an entity should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The term "effectively settled" replaces the term "ultimately settled" when used to describe recognition, and the terms "settlement" or "settled" replace the terms "ultimate settlement" or "ultimately settled" when used to describe measurement o a tax position under FIN No. 48. FIN No. 48-1 clarifies that a tax position can be effectively settled upon the completion of an examination by a taxing authority without being legally extinguished. For tax positions considered effectively settled, an entity would recognize the full amount of tax benefit, even if the tax position is not considered more likely than not to be sustained based solely on the basis of its technical merits and the statute of limitations remains open. The adoption of FIN No. 48-1, effective January 1, 2007, did not have an incremental effect on our consolidated financial statements.

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin ("SAB") No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 provides guidance on how the effects of prior year misstatements should be considered in quantifying misstatements in the current year financial statements. SAB No. 108 requires registrants to quantify misstatements using both the income statement ("rollover") and balance sheet ("iron curtain") approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. Historically, we evaluated uncorrected misstatements using the "rollover" method which resulted in an accumulation of quantitatively and qualitatively immaterial misstatements to our consolidated financial statements. SAB No. 108 provides for a one time transitional adjustment to retained earnings for errors which were not deemed material to prior year financial statements, but which is material under guidance of SAB No. 108. We adopted SAB No. 108 during the fourth quarter of 2006 and recorded a one-time adjustment to reduce retained earnings by $1.0 million.

In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment. In March 2005, the SEC issued Staff Accounting Bulletin ("SAB") No. 107, Share-Based Payment, regarding the interaction between SFAS No. 123(R) and certain SEC rules and regulations. Effective January 1, 2006, we adopted SFAS No. 123(R). We elected to use the modified prospective method for adoption, which requires compensation expense to be recognized in the statement of operations for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB No. 25 (as amended) to account for employee stock-based compensation. The adoption of SFAS No. 123(R) required the unamortized stock award recorded under APB No. 25 related to stock-based compensation awards as of January 1, 2006, in the amount of $0.8 million to be eliminated against additional paid-in-capital. See Stock-Based Compensation policy above and Note 9, Common Stock, for further discussion of the Company's accounting for share-based compensation awards.

Recently Issued Accounting Standards

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations ("SFAS No. 141R"). SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS No. 141R will become effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R will become effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109, Accounting for Income Taxes, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, Accounting for Uncertainty in Income Taxes, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. Upon our adoption of SFAS No. 141R effective January 1, 2009, we will recognize expense of $1.4 million in deferred acquisition related costs.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements—An Amendment of ARB No. 51. SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. Additionally, SFAS No. 160 establishes reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS No. 160 is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. We are evaluating the impact that SFAS No. 160 will have, if any, on our consolidated financial statements and related disclosures when it is adopted in 2009.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—An Amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. As SFAS No. 161 is disclosure related, we do not expect its adoption to have a material impact on our financial statements.

In January 2009, the SEC published its final rule, Modernization of Oil and Gas Reporting, which modifies the SEC's reporting and disclosure rules for oil and natural gas reserves. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and natural gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for our Form 10-K for the year ended December 31, 2009. Early adoption is not permitted. We are evaluating the impact that adoption of this final rule will have on our consolidated financial statements, related disclosure and management's discussion and analysis.

NOTE 2 – FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Financial Instruments.

Determination of fair value. We measure fair value based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to our nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use two investment grade financial institutions as our counterparties to our derivative contracts. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2008, no valuation allowance was recorded. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Valuation hierarchy. SFAS No. 157 establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Instruments included in Level 1 consist of our commodity derivatives for New York Mercantile Exchange ("NYMEX")-based natural gas swaps.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments included in Level 3 consist of our commodity derivatives for Colorado Interstate Gas ("CIG") and Panhandle Eastern Pipeline ("PEPL")-based natural gas swaps, oil swaps, natural gas basis protection swaps, oil and natural gas options, and physical sales and purchases.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents, for each hierarchy level, our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of December 31, 2008:

	Level 1	Level 3	Total
		(in thousands)	
Assets:			
Commodity based derivatives	$ 19,359	$ 144,677	$ 164,036
Liabilities:			
Commodity based derivatives	(658)	(9,828)	(10,486)
Net fair value of commodity based derivatives	$ 18,701	$ 134,849	$ 153,550

The following table sets forth a reconciliation of our Level 3 fair value measurements:

	Year Ended December 31, 2008 (in thousands)
Fair value, net asset (liability), beginning of period	$ (2,368)
Unrealized gains (losses) included in statement of operations line item:	
Cost of natural gas marketing activities	(1,079)
Unrealized gains (losses) included in balance sheet line item:	
Accounts receivable - affiliates	821
Accounts payable - affiliates	35,338
Purchases	
Oil and gas sales activities	105,214
Sales from natural gas marketing activities	438
Cost of natural gas marketing activities	(4,590)
Settlements	
Oil and gas sales activities	549
Sales from natural gas marketing activities	(129)
Cost of natural gas marketing activities	655
Fair value, net asset (liability), end of period	$ 134,849
Change in unrealized gains (losses) relating to assets (liabilities) still held as of December 31, 2008, included in statement of operations line item:	
Oil and gas price risk management, net	$ 105,214
Sales from natural gas marketing activities	438
Cost of natural gas marketing activities	(5,669)
	$ 99,983

See Note 3, Derivative Financial Instruments, for additional disclosure related to our derivative financial instruments.

Non-Derivative Financial Assets and Liabilities.

The carrying values of the financial instruments comprising cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The portion of our long-term debt related to our credit facility, approximates fair value due to the variable nature of its related interest rate. We estimate the fair value of the portion of our long-term debt related to our senior notes to be approximately $127 million or approximately 62.5% of par value as of December 31, 2008. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders participating in the trading of the securities.

NOTE 3 – DERIVATIVE FINANCIAL INSTRUMENTS

We are exposed to the effect of market fluctuations in the prices of oil and natural gas as they relate to our oil and natural gas sales and natural gas marketing segments. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivatives. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

Concentration of Credit Risk. A significant portion of our liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. These contracts consist of fixed price swaps, basis swaps and collars. We primarily use two investment grade financial institutions as our counterparties to our derivative contracts who are also major lenders in our credit facility arrangement. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2008, no valuation allowance was recorded.

As of December 31, 2008, the following counterparties expose us to credit risk.

	Fair Value of Derivatives As of December 31, 2008		
Counterparty Name	Assets	Liabilities (in thousands)	Net
JPMorgan Chase Bank, N.A. (1)	$ 83,291	$ (322)	$ 82,969
BNP Paribas (1)	79,316	-	79,316
Various (2)	1,429	(10,164)	(8,735)
Total	$ 164,036	$ (10,486)	$ 153,550

(1) Major lender in our credit facility, see Note 6.
(2) Represents a total of 48 counterparties, includes two lenders in our credit faciity.

Economic Hedging Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative contracts. As of December 31, 2008, our oil and natural gas derivative instruments were comprised of futures, swaps, basis protection swaps and collars. These instruments generally consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production, PEPL-based contracts for NECO production and CIG-based contracts for other Colorado production and NYMEX-based crude oil swaps for our Colorado oil production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the fixed put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

We purchase puts and set collars and swaps for our own and affiliated partnerships' production to protect against price declines in future periods while retaining much of the benefits of price increases. RNG enters into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market. We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. At December 31, 2008 and 2007, we had the following open commodity based derivative instruments designed as an economic hedge for a portion of our oil and natural gas production for periods after December 2008:

	Year Ended December 31, 2008	2007
	(in thousands)	
Derivative net assets (liabilities)		
Oil and gas sales activities:		
Fixed-price natural gas swaps	$ 55,747	$ -
Natural gas collars	50,752	2,969
Natural gas basis protection swaps	(4,292)	-
Natural gas floors	-	105
Fixed-price oil swaps	51,508	(5,097)
	153,715	(2,023)
Natural gas marketing activities:		
Fixed-price natural gas swaps	(159)	649
Natural gas basis protection swaps	(13)	-
Natural gas collars	7	-
	(165)	649
Estimated net fair value of derivative instruments	$ 153,550	$ (1,374)

In addition to including the gross assets and liabilities related to our share of oil and gas production, the above table and our consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into and those that we allocate to our affiliated partnerships as the managing general partner. See Note 11, Transactions with Affiliates, for a discussion of our allocation methodology. For those derivative contracts which we have allocated to the affiliated partnerships, we have on our consolidated balance sheets a corresponding payable to and receivable from the partnerships of $37.5 million and $1.6 million, respectively, as of December 31, 2008, and $1 million and $2.4 million as of December 31, 2007, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table identifies the fair value of commodity based derivatives as classified in our consolidated balance sheets.

	December 31, 2008	December 31, 2007
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	$ 116,881	$ 4,817
Other assets - long-term asset	47,155	193
	164,036	5,010
Fair value of derivatives - current liability	4,766	6,291
Other liabilities - long-term liability	5,720	93
	10,486	6,384
Net fair value of commodity based derivatives - asset (liability)	$ 153,550	$ (1,374)

The following changes in the fair value of commodity based derivatives are reflected in our consolidated statements of operations.

	Year Ended December 31,					
	2008		2007		2006	
Statement of operations line item	Realized	Unrealized	Realized	Unrealized	Realized	Unrealized
	(in thousands, gain/(loss))					
Oil and gas price risk management gain (loss), net (1)	$ 9,487	$ 118,351	$ 7,173	$ (4,417)	$ 1,895	$ 7,252
Sales from natural gas marketing activities (2)	(1,882)	4,614	3,870	(1,736)	2,592	12,291
Cost of natural gas marketing activities (2)	32	(5,429)	(482)	1,511	(1,908)	(11,923)

(1) Includes realized and unrealized gains and losses on commodity based derivative instruments related to PDC.
(2) Includes realized and unrealized gains and losses on commodity based derivatives instruments related to RNG only.

NOTE 4 – PROPERTIES AND EQUIPMENT

	December 31, 2008	2007
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	$ 1,245,316	$ 953,904
Unproved	32,768	41,023
Total oil and gas properties	1,278,084	994,927
Pipelines and related facilities	34,067	22,408
Transportation and other equipment	31,693	23,669
Land and buildings	14,570	11,303
Construction in progress (1)	275	2,929
	1,358,689	1,055,236
Accumulated DD&A	(325,611)	(209,372)
	$ 1,033,078	$ 845,864

(1) At December 31, 2007 includes costs primarily related to a new integrated oil and gas financial software system.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Suspended Well Costs

The following table identifies the capitalized exploratory well costs that are pending the determination of proved reserves and included in oil and gas properties on the consolidated balance sheets.

	2008	2007	2006
	(in thousands, except for number of wells)		
Beginning balance at January 1	$ 2,300	$ 765	$ 1,918
Additions to capitalized exploratory well costs pending the determination of proved reserves	15,644	3,953	12,016
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(10,259)	(878)	(13,169)
Capitalized exploratory well costs charged to expense	(6,505)	(1,540)	-
Ending balance at December 31	$ 1,180	$ 2,300	$ 765
Number of wells pending determination at December 31	6	3	1

As of December 31, 2008, none of the wells awaiting the determination of proved reserves have been capitalized for more than one year after the completion of drilling.

NOTE 5 - INCOME TAXES

For each of the years in the three-year period ended December 31, 2008, we utilized our tax election to currently expense approximately $30 million, $44 million and $55 million, respectively, of intangible drilling costs (“IDC”). This election substantially reduced our current tax expense but resulted in a correspondingly higher deferred tax expense as shown below. Additionally, in 2006, we had a substantial taxable gain from the sale of undeveloped oil and gas properties, see Note 13, Sale of Oil and Gas Properties. We have chosen to use the favorable deferral aspects of the Internal Revenue Code (“IRC”) Section 1031 like-kind exchange (“LKE”) rules to defer the tax liability on a portion of the gain realized by purchasing replacement properties, see Note 14, Acquisitions. Accordingly, our current and deferred provision for income taxes increased proportionately in 2006 due to the current and deferred tax associated with this large taxable gain. The components of our tax expense consisted of the following:

	2008	2007	2006
		(in thousands)	
Current:			
Federal	$ 6,198	$ 7,579	$ 54,467
State	(3,818)	1,201	8,739
Total current income taxes	2,380	8,780	63,206
Deferred:			

Federal	55,500	11,074	74,003
State	3,579	1,127	12,428
Total deferred income taxes	59,079	12,201	86,431
Total income taxes	$ 61,459	$ 20,981	$ 149,637

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

	2008	2007 (in thousands)	2006
Computed "expected" tax	$ 61,169	$ 18,966	$ 135,594
State income tax, net	5,265	1,907	13,744
Percentage depletion	(1,150)	(624)	(545)
Domestic production activities deduction	(249)	(374)	-
Other	(3,576)	1,106	844
	$ 61,459	$ 20,981	$ 149,637

In order to reduce current income taxes payable, we elected to expense, for income tax purposes, a large amount of IDC in each of the three years presented above. This expensing election reduces our domestic production activities deduction, which in 2008 and 2007 was statutorily equal to six percent of our qualified production activity income ("QPAI"), to $0.7 million and $1.1 million, respectively. In 2006, due to our decision to expense $55 million of IDC, our domestic production deduction, which in 2006 was statutorily equal to three percent of QPAI, was zero. In addition, the amount in "Other" for 2008 was primarily for discrete tax benefit realized upon the implementation of state tax strategies during the second and third quarters. The amount in "Other" for 2007 was primarily nondeductible tax penalties.

The federal examination of our 2005 and 2006 tax returns is currently ongoing with no significant adjustments noted as of December 31, 2008.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2008 and 2007, are presented below.

	2008	2007
	(in thousands)	
Deferred tax assets:		
Allowance for doubtful accounts	$ 205	$ 138
Drilling notes	27	31
Allowance for lease impairment	4,910	912
Litigation allowance	-	578
Deferred revenue related to cash withheld for future plugging cost	1,043	1,011
Deferred compensation	2,846	2,058
Asset retirement obligations	8,519	7,782
Unrealized loss - derivatives	-	703
Employee benefits	547	456
State tax credit - carryforward	309	-
Other	57	16
Total gross deferred tax assets	18,463	13,685
Less valuation allowance	-	-

Deferred tax assets		18,463		13,685
Deferred tax liabilities:				
Properties and equipment		(165,212)		(145,499)
Unrealized gains - derivatives		(44,199)		(55)
Total gross deferred tax liabilities		(209,411)		(145,554)
Net deferred tax liability	$	(190,948)	$	(131,869)
Classification in the Consolidated Balance Sheets:				
Net current deferred tax (liabilities) assets*	$	(28,355)	$	4,621
Net non-current deferred tax liability		(162,593)		(136,490)
Net deferred tax liability	$	(190,948)	$	(131,869)

* Included in other current assets on the consolidated balance sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

As noted above, deferred tax liabilities for properties and equipment increased in 2008 and 2007, primarily as a result of our election to expense $30 million and $44 million of IDC for income tax purposes.

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

We adopted the provisions of FIN No. 48 effective January 1, 2007. As a result of adoption, retained earnings decreased by $0.3 million, deferred income taxes payable decreased by $0.9 million, current income taxes payable increased by $0.2 million and the liability for unrecognized tax benefit increased by $1 million.

The following table sets forth a reconciliation of the total amounts of unrecognized tax benefits for 2008:

	(in thousands)
Balance, December 31, 2007	$ 888
Gross increases for tax positions of prior years	216
Gross increases for tax positions of current year	167
Balance, December 31, 2008	$ 1,271

Interest and penalties related to uncertain tax positions are recognized in income tax expense. As of January 1, 2008, and December 31, 2008, we have approximately $0.1 and $0.3 million of accrued interest related to uncertain tax positions, respectively. In addition, at December 31, 2008, $0.3 million of income tax penalties were accrued compared to $0.2 million accrued at January 1, 2008. The total amount of unrecognized tax benefits that would affect the effective tax rate, if recognized, is $0.9 million as of December 31, 2008 and $0.5 million as of January 1, 2008. We expect the unrecognized tax benefit at December 31, 2008, to decrease in the next twelve months because of the ongoing IRS examination of our 2005 and 2006 tax years that will be finalized in 2009. It is currently estimated that the decrease in our unrecognized tax benefits during the next year will be approximately $0.8 million.

The statute of limitations for tax years 2004-2007 remains open for both federal and state taxing jurisdictions. However, due to the July 31, 2007, completion date of the federal examination of our 2003 and 2004 tax years, we believe that certain tax positions related to these tax years have been “effectively settled” for federal tax purposes. Additionally, for the majority of our state tax jurisdictions, the statute of limitations for the 2003 tax year remains open at December 31, 2008.

Our subsidiary, Unioil Inc., which was acquired on December 6, 2006, filed separate tax returns for years prior to the acquisition date. Unioil's 2003-2006 tax returns remain open to examination at December 31, 2008. Any unrecognized tax benefit associated with Unioil's tax returns is included in the above table amount.

NOTE 6 - LONG-TERM DEBT

	December 31, 2008	December 31, 2007
	(in thousands)	
Credit facility	$ 194,500	$ 235,000
12% Senior notes due 2018, net of discount of $2.6 million	200,367	-
Total long-term debt	$ 394,867	$ 235,000

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Credit facility

We have a credit facility co-arranged by JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended last on November 12, 2008, dated as of November 4, 2005, with an available commitment of $375 million as of December 31, 2008. The credit facility, through a series of amendments, includes commitments from: Wachovia Bank N.A.; Bank of America, N.A.; Bank of Oklahoma; Allied Irish Banks p.l.c.; Guaranty Bank, FSB; Royal Bank of Canada; The Royal Bank of Scotland, plc; Calyon New York Branch; Compass Bank; The Bank of Nova Scotia; and BMO Capital Markets Financing, Inc. The maximum allowable commitment under the current credit facility is $400 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. Our credit facility borrowing base is subject to size redeterminations each April and October based upon a quantification of our reserves at December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment, as agreed upon by us and our lenders, is utilized to quantify our reserve reports and determine the underlying borrowing base.

We are required to pay a commitment fee of .5% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus .5%. ABR borrowings are assessed an additional margin spread up to 1.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.625% to 2.375% based upon the outstanding balance as a percentage of the available balance. The credit agreement requires, among other things, the maintenance of certain working capital and tangible net worth ratios. No principal payments are required until the credit agreement expires on November 4, 2010.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, (g) enter into transactions with our affiliates, (h) change the character of our business, (i) engage in hedging activities unless certain requirements are satisfied, (j) issue certain types of stock, and (k) make certain amendments to our organizational documents. The credit facility also requires us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. In addition, we are required to comply with certain financial tests and maintain certain financial ratios. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, or working capital ratio, and (b) not to exceed a maximum leverage ratio.

As of December 31, 2008, we had drawn $194.5 million from our credit facility compared to $235 million as of December 31, 2007. The borrowing rate on the outstanding balance was 4.6% as of December 31, 2008 compared to 7.1% as of December 31, 2007. Amounts outstanding under our credit facility are secured by substantially all of our properties. We were in compliance with all covenants at December 31, 2008, and expect to remain in compliance throughout 2009.

12% Senior Notes Due 2018

Our outstanding 12% senior notes were issued on February 8, 2008. The principal amount of the senior notes is $203 million, which is payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15. The senior notes were issued at a price of 98.572% of the principal amount. In addition, $5.4 million in costs associated with the issuance of the debt has been capitalized as a deferred loan cost. The original discount and the deferred loan costs are being amortized to interest expense over the term of the debt using the effective interest method. As a result of recent negative global financial market conditions, we estimate that the fair value of the senior notes was approximately $127 million or approximately 62.5% of par. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders participating in the trading of the securities.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. Additionally, we are subject to two incurrence covenants: 1) earnings before interest, taxes, depreciation, amortization and capital expenditures ("EBITDAX") of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. As of December 31, 2008, our EBITDAX was 8.3 times interest expense and total debt was 1.8 time EBITDAX. We were in compliance with all covenants as of December 31, 2008, and expect to remain in compliance throughout 2009.

The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if:

- a subsidiary is a guarantor under our senior credit facility; and
- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture. As of December 31, 2008, none of our subsidiaries were obligated as guarantors of our senior notes.

The indenture provides that at any time, which may be more than once, before February 15, 2011, we may redeem up to 35% of the outstanding notes with proceeds from one or more equity offerings at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest, as long as:

- at least 65% of the aggregate principal amount of the notes issued on February 8, 2008, remains outstanding after each such redemption; and
- the redemption occurs within 180 days after the closing of the equity offering.

The notes also provide that we may, at our option, redeem all or part of the notes, at any time prior to February 15, 2013, at the make-whole price set forth in the indenture, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption. Further, the indenture provides that upon a change of control, we must give holders of the notes the opportunity to put their notes to us for repurchase at a repurchase price of 101% of the principal amount, plus accrued and unpaid interest.

In connection with the issuance of the notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC related to an offer to exchange the notes for other freely tradable notes and to use commercially reasonable efforts to cause the registration statement to become effective on or prior to February 7, 2009. On April 24, 2008, we filed the related registration statement on Form S-4. The registration statement was declared effective May 23, 2008.

NOTE 7 - ASSET RETIREMENT OBLIGATIONS

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

	2008	2007
	(in thousands)	
Balance at beginning of year	$ 20,781	$ 11,966
Obligations assumed with development activities and acquisitions	1,189	7,909
	(114)	(93)

Obligations discharged with disposed properties and asset retirements		
Accretion expense	1,230	999
Balance at end of year	$ 23,086	$ 20,781

If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Approximately $0.1 million of the asset retirement obligations were classified as short-term and included in other accrued expenses as of December 31, 2008 and 2007.

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NOTE 8 - COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. We are a party to a pipeline expansion agreement with an unrelated third party, which is also currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to invest a minimum of $65 million to develop specified acreage in the Wattenberg Field, during a three-year period ending December 31, 2009. Such capital spending will include costs to drill new wells and the cost to recomplete existing wells in this area. Should we not meet the minimum commitment by December 31, 2009, we will be required to pay liquidated damages of $2 million, prorated based on our actual capital investment made to date. As of December 31, 2008, our total capital expenditures pursuant to the agreement were $61.3 million, resulting in a maximum potential liquidating damages charge of $0.1 million.

In connection with the acquisition of oil and gas properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells in the Appalachian Basin by January 2016. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of $25,000 per undrilled well for a total contingent obligation of $2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of December 31, 2008, we have drilled 28 wells pursuant to this agreement.

We have entered into contracts that provide firm transportation, sales and processing charges on pipeline systems which we transport or sale our natural gas and the natural gas of other companies, working interest owners and our affiliated partnerships. The remaining terms of the contracts range from two to 14 years and require us to pay these transportation and processing charges regardless if the required volumes are delivered or not. The table below represents our gross future minimum firm transportation, sales and processing charges as of December 31, 2008, for the periods indicated. We will record in our financial statements only our share based upon our working and net revenue interest in the wells.

Year	(in thousands)
2009	$ 8,391
2010	19,047
2011	18,443
2012	25,071
2013	25,262
Thereafter	121,281
	$ 217,495

In September 2008, we entered into a pipeline and processing plants expansion agreement with an unrelated party, which is currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to make a capital investment of $60 million, for our own benefit, over a three-year period commencing on January 1, 2009, to develop or facilitate production in our Wattenberg Field dedicated to this purchaser. If the purchaser fails to complete the pipeline and processing plants in accordance with the agreement, then the agreement effectively terminates. The agreement also provides for certain volume commitments to be obtained by December 31, 2012. Qualifying capital expenditures include the cost to drill new wells and the cost to recomplete existing wells in this area. Failure to meet our drilling commitment would result in a maximum payment to the counterparty of $15 million in 2012; failure to meet our volume delivery commitment by December 31, 2012, would result in a maximum payment to the counterparty of $10 million in 2013.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to our financial ability to do so. The maximum annual repurchase obligation as of December 31, 2008, was approximately $15.9 million. We have adequate liquidity to meet this obligation. During 2008 and 2007, we paid $1.8 million and $1.6 million, respectively, under this provision for the repurchase of partnership units. As of December 31, 2008, outstanding repurchase offers to investing partners totaled $0.7 million, of which $0.2 million were consummated in 2009 prior to expiration.

Performance Supplements. Our drilling programs formed from 1996 through the second quarter of 2005 contain a performance supplement that provides for changes in the distribution of partnership profits if certain levels of performance are not met. The terms of this provision in the partnership agreements are not a guarantee of a rate of return on an investment in the partnership. Under those specific conditions, such changes can result in our share of an affected partnership’s profits being reduced by up to one half of the amount to which we otherwise would be entitled in the affected period. In no event would we be obligated to assume a disproportionate share of losses in such partnerships; should the partnerships that contain this provision in the partnership agreements incur a loss, our share of such losses would be unaffected by the terms of this provision. In accordance with these provisions, our share of partnership profits was reduced by an aggregate of $1 million, $0.6 million, and $1 million during 2008, 2007and 2006, respectively. As of December 31, 2008 and 2007, based on production through December 31 of the corresponding year, we had accrued $0.3 million and $0.2 million, respectively.

Partnership Casualty Losses. As Managing General Partner of 33 partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

Drilling Rig Contracts. In order to secure the services for drilling rigs, we made commitments to the drilling contractors, which call for a minimum commitment of $12,500 daily for a specified amount of time if we cease to use the drilling rigs and a maximum commitment of $40,680 daily for a specified amount of time for daily use of the drilling rigs. As of December 31, 2008, commitments for these two separate contracts expire in August 2009 and July 2010. As of December 31, 2008, we have an outstanding minimum commitment for $4.2 million and an outstanding maximum commitment for $15.9 million, which includes $5.1 million related to a rig sublet to a third party and remains our obligation should the third party default on terms of the sublet agreement.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Litigation.

Colorado royalty. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells operated by us in parts of the State of Colorado (the "Droegemueller Action"). The plaintiff sought declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007. On October 10, 2008, the court preliminarily approved a settlement agreement between the plaintiffs and the Company, on behalf of itself and the partnerships for which the Company is the managing general partner. Based on the settlement terms, the settlement amount payable by the Company is $5.8 million. Such moneys, in addition to moneys related to the settlement on behalf of the partnerships for which the Company is the managing general partner, were deposited in an escrow account on November 3, 2008. We have accrued as of December 31, 2008, and included in other accrued expenses in our consolidated balance sheets, a related $5.8 million litigation reserve. We believe that the amount accrued is adequate to satisfy this obligation. Notice of the settlement was mailed to members of the class action suit in the fourth quarter of 2008. The final settlement approval hearing is expected on April 7, 2009.

See Note 17, Subsequent Events, regarding two West Virginia royalty lawsuits filed in January 2009.

Colorado Stormwater Permit. On December 8, 2008, we received a Notice of Violation /Cease and Desist Order (the "Notice") from the Colorado Department of Public Health, related to the stormwater permit for the Garden Gulch Road. The Company manages this private road for Garden Gulch LLC. The Company is one of four equal owners of Garden Gulch LLC, all of which are oil and gas companies operating in the Piceance region of Colorado. The Notice alleges a deficient and/or incomplete stormwater management plan, failure to implement best management practices and failure to conduct required permit inspections. The Notice requires corrective action and states that the recipient shall cease and desist such alleged violations. The Notice states that a violation could result in civil penalties up to $10,000 per day. The Company's initial response was submitted on February 6, 2009. No civil penalties have been imposed or requested at this time. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, the Company is unable to predict the ultimate outcome of this suit at this time.

We are involved in various other legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position or results of operations.

Employment Agreements with Executive Officers. We have employment agreements with our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and other executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation, and other various benefits, including retirement and termination benefits.

In the event of termination without cause or if an executive officer terminates employment for good reason, which includes a change in control, the executive officer is entitled to receive a payment in the amount up to three times the sum of his highest base salary during the previous two years of employment immediately preceding the termination date and his highest bonus received during the same two year period. The executive officer is also entitled to (i) vesting of any unvested equity compensation, (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of any earned and unpaid bonus amounts. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated.

In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and to provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

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

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

Derivative Contracts. We would be exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2008, 2007 or 2006.

NOTE 9 - COMMON STOCK

Stock-Based Compensation Plans

As approved by the shareholders in June 2004, we maintain a long-term equity compensation plan for our officers and certain key employees (the "2004 Plan"). In accordance with the plan, awards may be issued in the form of stock options, stock appreciation rights, restricted stock or performance shares. A total of 750,000 new shares of common stock have been reserved for issuance. Awards pursuant to the plan vest over periods set at the discretion of the Compensation Committee of our Board of Directors ("Board") and have a maximum exercisable period of ten years. As of December 31, 2008, 312,418 common shares remain available for future awards.

As approved by the shareholders, we also maintain a restricted stock plan for non-employee directors. A total of 100,000 new shares of common stock have been reserved for issuance under the plan. During 2008, 2007 and 2006, 14,000, 12,710 and 6,551 common shares, respectively, were awarded in accordance with the plan. Compensation expense for each of the years ended December 31, 2008, 2007 and 2006, related to these restricted shares was $1 million, $0.2 million and $0.1 million, respectively. As of December 31, 2008, 59,844 common shares remain available for future awards.

In August 1999, the shareholders approved the 1999 Incentive Stock Option and Non-Qualified Stock Option Plan. A total of 500,000 shares of our common stock were reserved for issuance upon the exercise of stock options. All shares authorized to be awarded pursuant to this plan were awarded in years prior to 2002. As of December 31, 2007, options for 11,000 common shares remained outstanding and exercisable; in 2008, these outstanding options were exercised.

The following table provides a summary of the effect of our stock based compensation plans on the results of operations for the periods presented.

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
	$ 6,702	$ 2,286	$ 1,516

Total stock-based compensation expense (1)			
Income tax benefit	(2,557)	(882)	(585)
Net income impact	$ 4,145	$ 1,404	$ 931

(1) 2008 includes $1.1 million related to a separation agreement with our former president and $1.5 million related to a retirement agreement with our former chief executive officer.

Stock Option Awards. As of December 31, 2008, all outstanding stock options were issued pursuant to our 2004 Plan. Outstanding options expire ten years from the date of grant and become vested and exercisable ratably over a four year period. We have not granted any new stock option awards since 2006. In 2008, pursuant to a separation agreement with our former president and an agreement with our former chief executive officer, we modified options to purchase 9,905 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial. The fair value of options modified in 2008 and granted in 2006, were estimated at the date of modification or grant using a Black-Scholes option-pricing model assuming no dividends and the following weighted average assumptions, with the exception of 4,678 shares in 2008, which were estimated to approximate fair value on the date of modification due to the short-term nature of the award:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Year Ended December 31, 2008	2006
Expected volatility	43.0%	40.4%
Expected term (in years)	-	6.0
Risk-free interest rate	1.6%	4.2%
Weighted-average grant date fair value per share	$ 18.03	$ 20.30

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

The following table provides a summary of our stock option award activity for the year ended December 31, 2008:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (years)
Outstanding at December 31, 2007	51,567	$ 33.55	6.4
Modified	9,905	43.03	
Exercised	(25,699)	24.41	
Forfeited	(17,422)	43.86	
Outstanding at December 31, 2008	18,351	41.68	6.8
Vested and expected to vest at December 31, 2008	18,351	41.68	6.8
Exercisable at December 31, 2008	12,736	40.41	6.6

	Year Ended December 31, 2008	2007	2006
	(in thousands, except market price)		
Total intrinsic value of options exercised	$ 659	$ 1,691	$ 281
Total intrinsic value of options outstanding	-	1,319	1,984
Total intrinsic value of options exercisable	-	971	1,934
Market price per common share as of December 31	24.07	59.13	43.05

The intrinsic value of options exercised represents the amount by which the market value of our stock at date of exercise exceeds the exercise price of the option. The intrinsic values of the options outstanding and exercisable represent the amount by which the closing market price of our common stock at the last trading day of the year exceeds the exercise price of the options. Total compensation cost related to stock options granted under the 2004 Plan not yet recognized as of December 31, 2008, was $0.1 million. This cost is expected to be recognized over a weighted average period of 1.5 years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Restricted Stock Awards

We have issued restricted stock awards with vesting conditions that are either time-based or market-based.

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, primarily over four years. Time-based awards for non-employee directors vest on July 1 of the year following the date of grant. Total intrinsic value is based upon the closing market price of our common stock on the last trading date of the year. In 2008, pursuant to a separation agreement with our former president and an agreement with our former chief executive officer, we modified time-based awards to vest 25,027 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award, resulting in an increase in the original fair value of $0.4 million.

The following table sets forth the changes in non-vested time-based awards for the year ended December 31, 2008:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2007	201,845	$ 37.97
Granted/modified	161,982	57.64
Vested	(110,562)	34.59
Forfeited	(35,205)	45.53
Non-vested at December 31, 2008	218,060	$ 52.59

	Year Ended December 31,		
	2008	2007	2006
	(in thousands, except market price)		
Total intrinsic value of time-based awards vested	$ 6,710	$ 2,208	$ 844
Total intrinsic value of time-based awards non-vested	5,249	10,161	5,671
Market price per common share as of December 31	24.07	59.13	43.05

Total intrinsic value of time-based awards vested is based on the closing market price of our common stock on the date of vest. Total intrinsic value of time-based awards not yet vested is based on the closing market price of our common stock on the last trading day of the year. The total compensation cost related to non-vested time-based awards not yet recognized as of December 31, 2008, was $8.8 million. This cost is expected to be recognized over a weighted-average period of 2.9 years.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years for market-based awards. The market-based shares vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. All compensation cost related to the market based-awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. In 2008, pursuant to a separation agreement with our former president, we modified market-based awards to vest 1,539 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award; pursuant to an agreement with our former chief executive officer, we modified market-based awards to vest 37,440 shares by accelerating the vesting schedule, none of which would have vested, nor was expected to vest, pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

The weighted average grant date fair value per market-based share, including shares modified pursuant to an agreement with our former chief executive officer, was computed using the Monte Carlo pricing model using the following weighted average assumptions:

	Year Ended December 31,	
	2008	2007
Expected term of award	3 years	3 years
Risk-free interest rate	2.7%	4.7%
Volatility	45.6%	44.0%
Weighted average grant date fair value per share	$ 43.61	$ 36.07

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table sets forth the changes in non-vested market-based awards for the year ended December 31, 2008:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2007	31,972	$ 36.07
Granted/modified	87,384	43.61
Vested	(3,078)	52.00
Forfeited	(43,595)	40.81
Non-vested at December 31, 2008	72,683	$ 41.62

The intrinsic value of market-based awards not yet vested at December 31, 2008 and 2007, was $1.7 million and $1.9 million, respectively, based upon the closing market price of our common stock on the last trading date of the year. The total compensation cost related to non-vested market-based awards not yet recognized as of December 31, 2008, is $1.4 million. This cost is expected to be recognized over a weighted-average period of 1.1 years.

Treasury Share Purchases

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

On October 16, 2006, our board of directors of approved a second 2006 purchase program authorizing us to purchase up to 10% (1,477,109 shares) of our then outstanding common stock through April 2008. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that we deem appropriate. There were 1,465,089 shares that were authorized but not yet purchased as of December 31, 2007. Total shares purchased in 2008 pursuant to the program were 64,263 common shares at a cost of $4.4 million ($67.97 average price paid per share), including 63,756 shares from our executive officers at a cost of $4.3 million ($67.98 price paid per share). Shares purchased in 2008 from employees, excluding executive officers, were generally purchased at fair market value based on the closing price on the date of purchase and were primarily purchased to satisfy the statutory minimum tax withholding requirement for restricted stock that vested in 2008. Shares purchased from executive officers in 2008 were primarily pursuant to a separation agreement with our former president and to satisfy the statutory minimum tax withholding requirements for shares vested in 2008. Shares purchased in prior years were generally purchased at fair market value based on the closing price on the date of purchase and were primarily purchased to satisfy the statutory minimum tax withholding requirement for shares vesting in prior years. The authorization to purchase the remaining 1,400,826 shares effectively expired on April 30, 2008. All shares purchased in accordance with the program have been subsequently retired.

Pursuant to our senior notes indenture entered on February 8, 2008, any future purchases are limited, see Note 6, Long-Term Debt.

Shareholders' Rights Agreement

On September 11, 2007, we entered into a rights agreement, with Transfer Online, Inc., as rights agent. The rights agreement is designed to improve the ability of our board of directors to protect the interest of our shareholders in the event of an unsolicited takeover attempt. Our Board declared a dividend of one right for each outstanding share of our common stock. The right dividend was paid to shareholders of record on September 14, 2007. A "distribution date," as defined in the rights agreement, can occur after any individual shareholder exceeds 15% ownership of our outstanding common stock. After the occurrence of a "distribution date," the right entitles each registered holder (other than the acquiring shareholder who triggered the "distribution date"), to purchase shares of our common stock (or, in certain circumstances, cash, property or other securities) having a then-current value equal to two times the exercise price of the right (i.e., for the $240 exercise price, the rights holder receives $480 worth of common stock). The exercise price is subject to adjustment for various corporate actions which affect all shareholders, such as a stock split. The rights agreement and all rights will expire on September 11, 2017.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Common and Preferred stock

Effective July 17, 2008, pursuant to shareholder approval, we amended and restated our Articles of Incorporation to: (1) increase the number of the Company's authorized shares of common stock, par value $0.01, from 50,000,000 shares to 100,000,000 shares, and (2) authorize 50,000,000 shares of Company preferred stock, par value $0.01, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by our Board of Directors from time to time. As of December 31, 2008, no preferred stock had been issued.

NOTE 10 - EMPLOYEE BENEFIT PLANS

We sponsor a qualified retirement plan covering substantially all of our employees. The plan consists of a 401(k) component and a profit sharing component. The 401(k) component enables eligible employees to contribute a portion of their compensation through pre-tax payroll deductions in accordance with specific guidelines. We provide a discretionary matching contribution based on a percentage of the employees' contributions up to certain limits. Our contribution to the profit sharing component is discretionary. Our total combined expense for both 401(k) and profit sharing in 2008, 2007 and 2006, was $1.9 million, $1.4 million and $3.1 million, respectively.

We provide a supplemental retirement benefit of deferred compensation under terms of the various employment agreements with certain executive officers. During 2008, 2007 and 2006, we charged $0.2 million, $0.4 million and $0.3 million related to this plan to general and administrative expenses, respectively, and we have recorded a related liability in the amount $2.4 million and $2.2 million as of December 31, 2008 and 2007, respectively.

In addition to the supplemental retirement benefit of deferred compensation, we offer a supplemental healthcare benefit covering certain executive officers and their spouses in accordance with each officer's employment agreement. Expense incurred during 2008 and 2007 related to this plan was immaterial. As of December 31, 2008 and 2007, we had a recorded liability of $0.6 million.

We maintain a non-qualified deferred compensation plan for our non-employee directors. The amount of compensation deferred by each participant is based on participant elections. The amounts deferred pursuant to the plan are invested in our common stock, maintained in a rabbi trust and are classified in the balance sheet as treasury shares as a component of shareholders' equity. The plan may be settled in either cash or shares as requested by the participant. As of December 31, 2008 and 2007, we had recorded a long-term liability of $0.2 million and $0.3 million, respectively, which is included in other liabilities in our consolidated balance sheets.

NOTE 11 - TRANSACTIONS WITH AFFILIATES

Funds held for future distribution on our consolidated balance sheets represent amounts owed to affiliated partnerships and others for production proceeds received by us on their behalf and undistributed as of December 31, 2008 and 2007.

Amounts due from/to the affiliated partnership are primarily related to derivative positions, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services.

We enter into derivative instruments for our own production as well as for our 33 affiliated partnerships' production. We enter into these derivative instruments for us and, as the managing general partner, for the affiliated partnerships jointly by area of operation. Prior to September 30, 2008, as volumes produced changed, the allocation between us and the affiliated partnerships changed. As of September 30, 2008, we fixed the allocation of the derivative positions between us and each affiliated partnership. Fixed quantities of each of the then existing positions were allocated to us and the affiliated partnerships based upon current estimated future production. For positions entered into subsequent to September 30, 2008, specific designations of the quantities between us and the affiliated partnerships are made at the time the positions are entered into based on estimated future production. As of December 31, 2008, we have recorded a payable to affiliates of $37.5 million representing their allocated portion of the fair value of our gross derivative assets and a due from affiliates of $1.6 million representing their allocated portion of the fair value of our gross derivative liabilities.

Our natural gas marketing segment manages the marketing of oil and natural gas for our affiliated partnerships in the Appalachian Basin. Our sales from natural gas marketing activities include $12.4 million, $9.3 million and $17.6 million in 2008, 2007 and 2006, respectively, related to the marketing of oil and natural gas on behalf of our affiliated partnerships. Included in our cost of natural gas marketing activities is $12.1 million, $9.1 million and $17.3 million for 2008, 2007 and 2006, respectively, related to these sales.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

We provided oil and gas well drilling services to our affiliated partnerships. Pursuant to our cost-plus drilling arrangements and our corresponding net presentation, we performed drilling services for our affiliated partnerships totaling $68 million, $68.4 million and $87 million in 2008, 2007 and 2006, for which we recognized $7.6 million, $11.4 million and $12.4 million in oil and gas well drilling operations revenue, respectively. As part of the oil and gas well drilling services we provide to our affiliated partnerships, we sell to them at cost the oil and gas leases upon which the wells are drilled. For the years ended December 31, 2008, 2007 and 2006, we sold to our affiliated partnerships leases in the amounts of $0.5 million, $1.4 million and $1.8 million, respectively. Further, we provide well operations and pipeline services to our affiliated partnerships. Substantially all of our revenue and expenses related to oil and gas well drilling operations and revenues from well operations and pipeline income are associated with services provided to our affiliated partnerships.

Revenues from oil and gas well drilling operations and costs of oil and gas well drilling operations each include $0.1 million during 2006 related to investments made by executive officers for working interests in wells drilled during in 2006. Amounts invested by the executive officers during 2007 were immaterial. No amounts were invested by the executive officers during 2008.

Management fees collected from the affiliated partnerships were $1.3 million in each of the years 2007 and 2006. Management fees are included in other income on our consolidated statements of operations. In 2008, we did not offer a drilling partnership; therefore, no management fee was collected from an affiliated partnership in 2008.

Through our wholly-owned subsidiary, PDC Securities Incorporated, we act as Dealer-Manager of the drilling partnerships. PDC Securities receives the applicable commissions and marketing allowances from the Escrow Agent of the drilling program and distributes them to the soliciting broker/dealers who sell the programs. The commissions and marketing allowances received by PDC Securities are included in other income net of the commissions distributed to the soliciting broker/dealer. The commissions and marketing allowances retained by PDC Securities were $0.5 million and $0.6 million and those distributed to the soliciting broker/dealers amounted to $8.3 million and $8.8 million for the years ended December 31, 2007 and 2006, respectively. In 2008, we did not offer a drilling partnership; therefore, no commissions and marketing allowances were received, distributed or retained by PDC Securities.

NOTE 12 - LEASE OBLIGATIONS

We have entered into operating leases principally for the leasing of natural gas compressors, office space in Denver and Bridgeport, and general office equipment. The future minimum lease payments under these non-cancelable operating leases as of December 31, 2008, are as follows:

Year	(in thousands)
2009	$ 2,687
2010	1,645
2011	1,081
2012	309
2013	74
Thereafter	44
	$ 5,840

Operating lease expense for the years ended December 31, 2008, 2007 and 2006, was $2.5 million, $1.5 million and $0.4 million, respectively.

NOTE 13 - SALE OF OIL AND GAS PROPERTIES

Grand Valley Field Properties

In July 2006, we sold to an unaffiliated company a portion of our undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. The sale encompassed 100% of the working interest in approximately 8,700 acres, including approximately 6,400 acres of the Chevron leasehold and 2,300 acres of the Puckett Land Company leasehold. We retained approximately 475 undeveloped locations on 10 acre spacing on the Grand Valley Field leasehold in addition to all of our producing properties in the field. The proceeds from the sale were $353.6 million. We recorded a gain on sale of leaseholds of $328 million and a deferred gain on sale of leaseholds of $25.6 million.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Pursuant to the purchase and sale agreement, we were obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per un-drilled well for a total contingent obligation of $25.6 million, which was reflected as a deferred gain on sale of leaseholds on the balance sheet as of December 31, 2006. In May 2007, we entered into a letter agreement amending the original purchase and sale agreement. The letter agreement relieved us of the obligation, in its entirety, to either drill 16 wells or pay liquidated damages, resulting in the recognition of the remaining $25.6 million deferred gain on sale of leaseholds in the second quarter of 2007. Pursuant to the letter agreement, we were obligated to drill six wells on specifically identified acreage. As of December 31, 2007, we had drilled all six wells, which were drilled on the unaffiliated party's leasehold for its benefit and at its cost.

In conjunction with the purchase and sale agreement described above, we entered into a LKE agreement, in accordance with Section 1031 of the Internal Revenue Code, with a “qualified intermediary.” Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. We had until mid-January 2007 to close any acquisition of suitable like-kind property, allowing us to take advantage of the income tax deferral benefits of a LKE transaction.

In December 2007, we sold to the same unaffiliated party above a portion of our North Dakota properties for approximately $34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and approximately 72,000 net undeveloped acres. The reduction in our production and proved reserves as a result of this transaction is not material. We recorded a gain on sale of leaseholds of $7.7 million in the fourth quarter of 2007. Following the sale, we retain ownership in three producing wells in Dunn County, ten producing wells in Burke County and approximately 60,000 acres of undeveloped leasehold in Burke County.

NOTE 14 – ACQUISITIONS

2007 Acquisitions

Acquisition of Internal Revenue Code Section 1031 – Like-Kind Exchange Properties

During the first quarter of 2007, we completed the acquisition of suitable like-kind properties in accordance with the LKE agreement we entered into in connection with our sale of undeveloped leaseholds located in Grand Valley Field, Garfield County, Colorado in July 2006. We acquired, for cash, qualifying oil and gas properties totaling $188.9 million, including costs of acquisition, as described below.

EXCO Properties. On January 5, 2007, we completed the purchase of producing properties and undeveloped drilling locations and acreage in the Wattenberg Field of the DJ Basin, Colorado from EXCO Resources Inc., an unaffiliated party. The acquisition included substantially all of EXCO’s assets in the area and encompassed 144 oil and natural gas wells (approximating 25.5 Bcfe proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold interests. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. We operate the assets and hold a majority working interest in the properties.

Company Sponsored Partnerships. On January 10, 2007, we completed the purchase of the remaining working interests in 44 of our sponsored partnerships. The transaction resulted in an increase in our ownership in 718 gross

(423 net) wells that we currently operate. The wells are located primarily in the Appalachian Basin and Michigan.

The following table presents the adjusted purchase price for the like-kind exchange property acquisitions described above as of December 31, 2007.

	EXCO	Partnerships
	(in thousands)	
Cash consideration paid	$ 128,672	$ 57,776
Plus: direct costs of acquisition	1,662	1,664
Less: acquisition cost adjustments	(119)	(2,792)
Total acquisition cost	$ 130,215	$ 56,648

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents, as of the respective date of acquisition, the final allocations of the purchase prices based on estimates of fair value.

	EXCO	Partnerships
	(in thousands)	
Current assets acquired	$ 91	$ -
Proved oil and gas properties	117,099	59,081
Unproved oil and gas properties	14,960	-
Asset retirement obligation	(422)	(2,433)
Other liabilities assumed	(1,513)	-
Total acquisition cost	$ 130,215	$ 56,648

The assessment of fair value of proved oil and gas properties acquired was based primarily on projections of expected discounted future cash flows of acquired oil and natural gas reserves. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable reserves were reduced by additional risk-weighting factors in that valuation.

Other. In January 2007, we acquired from unaffiliated parties other like-kind undeveloped leaseholds in Erath County, Texas for $2.1 million, including costs of acquisition. Acreage in this area is prospective for development of oil and natural gas reserves in the Barnett Shale.

Other Acquisitions

On February 22, 2007, we acquired, from an unaffiliated party, 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $12 million, which was allocated to oil and gas properties.

On October 30, 2007, with an effective date of October 1, 2007, we purchased from unrelated parties, Castle Gas Company, et.al., a majority working interest in 762 natural gas wells located in southwestern Pennsylvania for approximately $54 million. We estimated that the acquisition included approximately 47 Bcfe of reserves, or 31 Bcfe of proved reserves and 16 Bcfe of unproved reserves. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage.

The following table presents the adjusted purchase price for the Castle acquisition described above as of December 31, 2007.

	(in thousands)
Cash consideration paid	$ 53,041
Plus: direct costs of acquisition	443
Plus: acquisition cost adjustments	583

Total acquisition cost	$	54,067

The following table presents, as of the respective date of acquisition, the final allocation of the purchase price based on estimates of fair value.

		(in thousands)
Current assets acquired	$	185
Proved oil and gas properties		55,778
Unproved oil and gas properties		217
Real estate and equipment, and other assets		2,115
Non current assets		783
Asset retirement obligation		(4,043)
Other liabilities assumed		(968)
Total acquisition cost	$	54,067

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The assessment of fair value of proved oil and gas properties acquired was based primarily on projections of expected discounted future cash flows of acquired oil and natural gas reserves. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable reserves were reduced by additional risk-weighting factors in that valuation.

Pro Forma Financial Information

The results of operations for all of the above acquisitions have been included in our consolidated financial statements from the dates of acquisition. The pro forma effect of the inclusion in our consolidated statement of operations for the year ended December 31, 2007, of the results of operations for the January and February 2007 acquisitions described above, individually and in the aggregate, was not material.

The following unaudited pro forma financial information presents a summary of our consolidated results of operations for the years ended December 31, 2007 and 2006, assuming the acquisitions of the EXCO properties, our sponsored partnerships and the Castle properties had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase price to the acquired net assets. The pro forma effect of the inclusion of the results of operations for all of the other acquisitions described above, individually and in the aggregate, was not material.

	Year Ended December 31, (in thousands, except per share data)	
	2007	2006
Total revenues	$ 310,351	$ 315,492
Net income	$ 34,571	$ 243,105
Earnings per common share:		
Basic	$ 2.34	$ 15.52
Diluted	$ 2.33	$ 15.44

The pro forma results of operations are not necessarily indicative of what our results of operations would have been had the EXCO properties, our sponsored partnerships and the Castle properties been acquired at the beginning of the periods indicated, nor does it purport to represent our results of operations for any future periods.

2006 Acquisitions

On December 6, 2006, we completed a cash tender offer and purchased approximately 95.5% or 9,112,750 shares of the outstanding common stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The acquisition of more than 90% of the outstanding shares of common stock allowed us to effect a short-form merger of Unioil and one of our wholly-owned subsidiaries, resulting in the acquisition of the remaining 428,719 shares of Unioil. Each share of Unioil common stock not tendered through the offer was converted into the right to receive $1.91 in cash, the same consideration paid for shares in the tender offer. The total price paid for 100% of Unioil’s outstanding common stock was $18.6 million, including $0.4 million in direct costs of the acquisition. The final acquisition cost allocation as reflected on our consolidated balance sheets as of December 31, 2007, included $25.8 million in properties and equipment, current assets of $0.7 million, a deferred tax liability of $6.8 million and other liabilities assumed of $1 million. The pro forma effect of the inclusion of Unioil in our 2006 results of operations was not material.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 15 – MAJOR CUSTOMERS

The following table identifies sales to individual customers constituting 10% or more of oil and natural gas sales, including natural gas sales by our natural gas marketing activities segment, and total revenues.

	Oil and Gas Sales Year Ended December 31,			Total Revenues Year Ended December 31,		
	2008	2007	2006	2008	2007	2006
Customer						
Williams Production RMT Company	16.3%	14.1%	8.7%	12.4%	12.9%	7.5%
Tepco Crude Oil, LLC	14.3%	14.8%	14.9%	10.8%	13.5%	12.9%
DCP Midstream, LP	8.8%	7.8%	10.6%	6.6%	7.1%	9.1%
Sempra Energy Trading	5.4%	6.0%	10.3%	4.1%	5.5%	8.9%

NOTE 16 - BUSINESS SEGMENTS

We separate our operating activities into four segments: oil and gas sales, natural gas marketing, well operations and pipeline income and oil and gas well drilling operations. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Sales. Our oil and gas sales segment represents revenues and expenses from the production and sale of oil and natural gas. Segment revenue includes oil and gas price risk management, net. Segment profit consists of oil and gas sales revenues less its proportionate share of oil and gas production and well operations cost, exploration expense, direct general and administrative expense and DD&A expense. Segment DD&A expense was $100.2 million, $68.1 million and $31.3 million in 2008, 2007 and 2006, respectively.

Natural Gas Marketing Activities. Our natural gas marketing segment is composed of our wholly owned subsidiary, RNG, through which we purchase, aggregate and resell natural gas produced by us and others. Segment profit primarily represents sales from natural gas marketing activities and direct interest income less costs of natural gas marketing activities, direct general and administrative expense.

Well Operations and Pipeline Income. We charge our affiliated partnerships and other third parties competitive industry rates for well operations and natural gas gathering. Segment revenue includes monthly operating and gas gathering fees we charge for each well in which we operate that is owned by others, including our sponsored partnerships. Segment profit consists of well operations and pipeline income revenues less its proportionate share of oil and gas production and well operations cost and direct DD&A expense. Segment DD&A expense was $1.9 million, $1.2 million and $1.9 million in 2008, 2007, 2006, respectively.

Oil and Gas Well Drilling Operations. We drill natural gas wells for Company-sponsored drilling partnerships and retain an interest in each well. Our drilling and development segment reflects results of drilling and development activities conducted for affiliated and non-affiliated parties. Segment profit consists of oil and gas well drilling revenues less cost of oil and gas well drilling.

Other. This segment includes unallocated corporate general administrative expense, direct DD&A expense, direct interest income and interest expense.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Segment information for the years ended December 31, 2008, 2007 and 2006 is presented below.

Year Ended December 31,	2008	2007	2006
Revenues:		(in thousands)	
Oil and gas sales	$ 449,715	$ 177,943	$ 124,336
Natural gas marketing activities	140,263	103,624	131,326
Well operations and pipeline income	11,474	9,342	10,704
Oil and gas well drilling operations	7,615	12,154	17,917
Unallocated amounts	293	2,172	2,220
Total	$ 609,360	$ 305,235	$ 286,503
Segment Income Before Income Taxes:			
Oil and gas sales	$ 231,885	$ 42,068	$ 61,868
Natural gas marketing activities	1,329	3,822	1,816
Well operations and pipeline income	3,933	3,136	2,823
Oil and gas well drilling operations	5,402	9,646	5,300
Unallocated amounts	(67,781)	(4,482)	315,602
Total	$ 174,768	$ 54,190	$ 387,409
Expenditures for Segment Long-Lived Assets:			
Oil & gas sales	$ 309,395	$ 226,801	$ 133,401
Natural gas marketing activities	-	-	-
Well operations and pipeline income	7,564	6,715	1,419
Oil and gas well drilling operations	-	-	-
Unallocated amounts	6,194	5,472	12,125
Total	$ 323,153	$ 238,988	$ 146,945
As of December 31,			
Segment Assets:			
Oil & gas sales	$ 1,247,687	$ 862,237	$ 394,952
Natural gas marketing activities	50,117	40,269	39,899
Well operations and pipeline income	50,052	26,156	28,895
Oil and gas well drilling operations	2,028	4,959	87,746
Unallocated amounts	52,820	116,858	332,795
Total	$ 1,402,704	$ 1,050,479	$ 884,287

NOTE 17 – SUBSEQUENT EVENTS

West Virginia royalty litigation. On January 26, 2009, we received notice of a lawsuit filed in West Virginia state court in Barbour County, Beymer and Beymer v. Petroleum Development Corporation and Riley National Gas Company, CA No. 09-C-3 (“Beymer lawsuit”) , alleging a class action for failure to properly pay royalties. The allegations state that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages are requested in addition to breach of contract, tort, and fraud allegations. On February 25, 2009, we filed to remove the action to federal court.

On January 30, 2009, the Company was served with another lawsuit alleging class action related to royalty payments file in West Virginia state court in Harrison County, Gobel, Phares and Cather v. Petroleum Development Corporation, CA No. 09-40-2. West Virginia oil and gas production constitutes approximately 8% of the Company's current oil and gas sales. Given the preliminary stage of these proceedings and the inherent uncertainty in litigation, the Company is unable to predict the ultimate outcome of these suits at this time.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 18 – SUPPLEMENTAL OIL AND GAS INFORMATION – UNAUDITED

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

We incurred costs in oil and gas property acquisition, exploration and development are presented below.

	Year Ended December 31, 2008	2007	2006
	(in thousands)		
Acquisition of properties:			
Proved properties	$ 6,147	$ 257,330	$ 802
Unproved properties	6,890	13,701	11,926
Development costs	257,656	194,031	114,487
Exploration costs:			
Exploratory drilling	26,499	12,972	18,660
Geological and Geophysical	2,121	6,299	2,234
Total costs incurred	$ 299,313	$ 484,333	$ 148,109

The proved reserves attributable to the development costs in the above table were 125,198 MMcf and 2,354 MBbls for 2008, 216,383 MMcf and 3,700 MBbls for 2007 and 64,126 MMcf and 2,955 MBbls for 2006. Of the above development costs incurred for the years ended December 31, 2008, 2007 and 2006, the amounts of $66.2 million, $37.1 million, and $20.1 million, respectively, were incurred to develop proved undeveloped properties from the prior year end.

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, recompletions and to provide facilities to extract, treat, gather and store oil and gas. Exploration costs include costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves.

Capitalized Oil and Gas Costs

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

	December 31, 2008	2007
	(in thousands)	
Proved oil and gas properties	$ 1,245,316	$ 953,904
Unproved oil and gas properties	32,768	41,023

		1,278,084		994,927
Less accumulated depreciation, depletion and amortization		306,142		196,310
	$	971,942	$	798,617

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Results of Operations for Oil and Gas Producing Activities

The results of operations for oil and gas producing activities, excluding natural gas marketing activities, are presented below.

	Year Ended December 31, 2008	2007	2006
	(in thousands)		
Revenue:			
Oil and gas sales	$ 321,877	$ 175,187	$ 115,189
Oil and gas price risk management gain, net	127,838	2,756	9,147
	449,715	177,943	124,336
Expenses:			
Production costs	72,518	44,238	20,855
Depreciation, depletion and amortization	100,207	68,086	30,988
Exploration costs	45,105	23,551	8,131
	217,830	135,875	59,974
Results of operations for oil and gas producing activities before provision for income taxes	231,885	42,068	64,362
Provision for income taxes	86,493	16,280	24,818
Results of operations for oil and gas producing activities, excludes corporate overhead and interest costs	$ 145,392	$ 25,788	$ 39,544

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

Net Proved Oil and Gas Reserves

We utilized the services of independent petroleum engineers to estimate our oil and gas reserves. For the years ended December 31, 2008 and 2007, our reserve estimates for the Appalachian and Michigan Basins are based on reserve reports prepared by Wright & Company and for the Rocky Mountain Region, reserve estimates are based on reserve reports prepared by Ryder Scott Company, L.P. For the year ended December 31, 2006, our reserve estimates for the Appalachian and Michigan Basins and NECO Area were based on reserve reports prepared by Wright & Company and our reserve estimates for the Rocky Mountain Region, with the exception of the NECO properties, were based on reserve reports prepared by Ryder Scott. These reserve estimates have been prepared in compliance with professional standards and the reserves definitions prescribed by the SEC.

Proved reserves are the estimated quantities of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. The Company's net proved reserve estimates have been adjusted as necessary to reflect all contractual agreements, royalty obligations and interests owned by others at the time of the estimate.

Proved developed reserves are the quantities of oil and natural gas expected to be recovered through existing wells with existing equipment and operating methods. In some cases, proved undeveloped reserves may require substantial new investments in additional wells and related facilities.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the U.S., is shown below.

	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)
Proved Reserves:			
Proved reserves, January 1, 2006	4,538	247,288	274,516
Revisions of previous estimates	226	(21,721)	(20,365)
Extensions, discoveries and other additions			
Michigan Basin	-	225	225
Rocky Mountain Region	2,955	63,901	81,631
Purchases of reserves			
Appalachian Basin	-	222	222
Michigan Basin	-	35	35
Rocky Mountain Region	276	3,504	5,160
Dispositions to partnerships	(92)	(1,215)	(1,767)
Production	(631)	(13,161)	(16,947)
Proved reserves, December 31, 2006	7,272	279,078	322,710
Revisions of previous estimates	1,375	14,177	22,427
Extensions, discoveries and other additions			
Appalachian Basin	-	5,493	5,493
Michigan Basin	-	488	488
Rocky Mountain Region	3,700	210,402	232,602
Purchases of reserves			
Appalachian Basin	2	63,014	63,026
Michigan Basin	-	6,059	6,059
Rocky Mountain Region	4,490	39,239	66,179
Dispositions to partnerships	(591)	(1,874)	(5,420)
Production	(910)	(22,513)	(27,973)
Proved reserves, December 31, 2007	15,338	593,563	685,591
Revisions of previous estimates	(1,538)	(25,216)	(34,444)
Extensions, discoveries and other additions			
Appalachian Basin	-	24,875	24,875
Rocky Mountain Region	2,354	100,323	114,447
Purchases of reserves			
Appalachian Basin	-	83	83
Michigan Basin	-	46	46
Rocky Mountain Region	106	1,712	2,348
Dispositions to partnerships	(63)	(769)	(1,147)

Production	(1,160)	(31,760)	(38,720)
Proved reserves, December 31, 2008	15,037	662,857	753,079
Proved Developed Reserves(1), as of:			
January 1, 2006	2,848	146,664	163,752
December 31, 2006	3,503	144,672	165,690
December 31, 2007	5,219	286,570	317,884
December 31, 2008	5,438	297,041	329,669

(1) December 31, 2008, 2007, 2006, and January 1, 2006, reserve amounts reflect the reclassification of our Rocky Mountain Region refrac and behind pipe reserves of 75,863 MMcfe, 49,801 MMcfe, 21,062 MMcfe and 14,762 MMcfe, respectively, from proved developed to proved undeveloped.

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2008 Activity. In 2008, we recorded a downward revision of our previous estimate of proved reserves of approximately 34 Bcfe. The revision was primarily due to a decrease of approximately 50 Bcfe due to lower commodity prices, 26 Bcfe due to increased operating costs, and 15 Bcfe due to adjustments to proved undeveloped reserve values, partially offset be an increase of 55 Bcfe due to asset performance. New discoveries and extensions of 139 Bcfe in 2008 are due to drilling of 229 net wells and the addition of new proved undeveloped reserves. Approximately 25 Bcfe were added in the Appalachian Basin, and approximately 114 Bcfe were added in the Rocky Mountain Region with 26 Bcfe in the Wattenberg Field, 80 Bcfe in Grand Valley Field, and 8 Bcfe in the NECO area. We acquired approximately 2 Bcfe of proved reserves through the purchases of interest in some of our existing properties. We primarily acquired reserves in the Wattenberg Field with the remaining reserves being split between the Appalachian Basin, Michigan, Piceance, the NECO area and North Dakota. We sold proved reserves of approximately 1 Bcfe to unaffiliated third parties and to our sponsored partnerships for drilling activity.

2007 Activity. In 2007, we recorded an upward revision to our previous estimate of proved reserves of approximately 22 Bcfe. The revision was primarily due to an increase of approximately 25 Bcfe and 12 Bcfe, respectively, due to asset performance and higher commodity prices, partially offset by a decrease of approximately 15 Bcfe due primarily to increased operating costs, adjustments to proved undeveloped reserve values and change in well ownership interests. New discoveries and extensions of 239 Bcfe in 2007 are due to the drilling of 218 net wells and the addition of new proved undeveloped reserves. Approximately 233 Bcfe were added in the Rocky Mountain Region, with 43 Bcfe in the Wattenberg Field, 170 Bcfe in Grand Valley Field and 19 Bcfe in the NECO area. We acquired approximately 135 Bcfe of proved reserves through purchases of oil and natural gas properties. In the Rocky Mountain Region approximately 66 Bcfe of proved reserves were acquired in the Wattenberg Field, in the Appalachian Basin approximately 75 Bcfe were acquired and approximately 6 Bcfe in the Michigan Basin. We sold proved reserves of approximately 5 Bcfe to unaffiliated third parties and to our sponsored partnerships for drilling activity.

2006 Activity. In 2006 we recorded a downward revision to our previous estimate of proved reserves of approximately 20 Bcfe. The revision was primarily due to a decrease of 3 Bcfe due to asset performance and a decrease of 10 Bcfe due to lower commodity prices and a decrease of approximately 7 Bcfe due to changes in proved undeveloped reserve value, operating expense, and well ownership interests. New discoveries and extensions in 2006 of approximately 82 Bcfe were primarily due to the drilling of 91 net wells and adding new proved undeveloped reserves in the Rocky Mountain Region. Approximately 34 Bcfe were added in Wattenberg Field, 33 Bcfe in Grand Valley Field and 12 Bcfe in the NECO area. We acquired approximately 5 Bcfe of proved reserves through purchases of oil and natural gas properties in Wattenberg Field. We sold proved reserves of approximately 2 Bcfe to our sponsored partnerships.

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

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

	2008	2007 (in thousands)	2006
Future estimated cash flows	$ 3,867,461	$ 5,257,962	$ 1,804,796
Future estimated production costs	(1,325,362)	(1,374,027)	(571,346)
Future estimated development costs	(1,100,533)	(876,961)	(373,460)
Future estimated income tax expense	(384,676)	(1,159,489)	(334,536)
Future net cash flows	1,056,890	1,847,485	525,454
10% annual discount for estimated timing of cash flows	(700,085)	(1,094,414)	(309,792)
Standardized measure of discounted future estimated net cash flows	$ 356,805	$ 753,071	$ 215,662

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

	2008	2007	2006
		(in thousands)	
Sales of oil and gas production net of production costs	$ (261,692)	$ (137,725)	$ (94,337)
Net changes in prices and production costs	(479,894)	157,797	(301,132)
Extensions, discoveries, and improved recovery, less related costs	80,859	317,031	46,109
Sales of reserves	(2,012)	(7,846)	(3,356)
Purchase of reserves	4,280	342,792	11,003
Development costs incurred during the period	88,008	42,510	20,051
Revisions of previous quantity estimates	(79,536)	92,462	(22,090)
Changes in estimated income taxes	239,054	(335,327)	120,818
Accretion of discount	122,409	38,660	62,838
Timing and other			
Timing	(20,117)	27,055	(29,672)
Net changes in future development costs	(87,625)	-	-
Total	$ (396,266)	$ 537,409	$ (189,768)

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

The estimated present value of future cash flows relating to proved reserves is extremely sensitive to prices used at any measurement period. The average December 31 price used for each commodity at December 31, 2008, 2007 and 2006 is presented below.

	Average Price	
As of December 31,	Oil	Gas
2008	$ 37.85	$ 4.98
2007	80.67	6.77
2006	57.70	4.96

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 19 - QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly financial data for the years ended December 31, 2008 and 2007, are presented below The sum of the quarters may not equal the total of the year's net income per share due to changes in the weighted average shares outstanding throughout the year.

	2008 Quarter Ended				
	3/31/2008	6/30/2008	9/30/2008	12/31/2008	Year Ended
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 71,646	$ 94,549	$ 99,422	$ 56,260	$ 321,877
Sales from natural gas marketing activities	23,325	30,941	53,372	32,625	140,263
Oil and gas well drilling	3,083	2,887	1,232	413	7,615
Well operations and pipeline income	2,352	2,438	3,356	3,328	11,474
Oil and gas price risk management gain (loss), net	(42,310)	(101,798)	169,402	102,544	127,838
Other income	3	34	20	236	293
Total revenues	58,099	29,051	326,804	195,406	609,360
Costs and expenses:					
Oil and gas production and well operations costs	18,132	20,815	22,173	17,089	78,209
Cost of natural gas marketing activities	22,121	30,117	54,372	32,624	139,234
Cost of oil and gas well drilling	78	518	501	1,116	2,213
Exploration expense	4,283	3,467	10,212	27,143	45,105
General and administrative expense	9,823	9,231	8,106	10,555	37,715
Depreciation, depletion and amortization	21,131	22,105	28,645	32,694	104,575
Total costs and expenses	75,568	86,253	124,009	121,221	407,051
Income (loss) from operations	(17,469)	(57,202)	202,795	74,185	202,309
Interest income	271	75	151	94	591
Interest expense	(4,932)	(6,394)	(7,817)	(8,989)	(28,132)
Income (loss) before income taxes	(22,130)	(63,521)	195,129	65,290	174,768
Provision (benefit) for income taxes	(8,202)	(22,809)	68,233	24,237	61,459
Net income (loss)	$ (13,928)	$ (40,712)	$ 126,896	$ 41,053	$ 113,309
Earnings per common share:					
Basic	$ (0.95)	$ (2.76)	$ 8.59	$ 2.78	$ 7.69

Diluted	$ (0.95)	$ (2.76)	$ 8.55	$ 2.78	$ 7.63
Weighted average common and common equivalent shares outstanding:					
Basic	14,738	14,742	14,767	14,778	14,736
Diluted	14,738	14,742	14,835	14,791	14,848

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	2007 Quarter Ended				
	3/31/2007	6/30/2007	9/30/2007	12/31/2007	Year Ended
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 34,016	$ 39,246	$ 44,437	$ 57,488	$ 175,187
Sales from natural gas marketing activities	21,987	29,924	19,934	31,779	103,624
Oil and gas well drilling	4,030	1,739	1,573	4,812	12,154
Well operations and pipeline income	3,298	1,292	2,092	2,660	9,342
Oil and gas price risk management (loss) gain, net	(5,645)	3,742	6,345	(1,686)	2,756
Other income	226	2	1,894	50	2,172
Total revenues	57,912	75,945	76,275	95,103	305,235
Costs and expenses:					
Oil and gas production costs and well operations costs	9,035	11,628	12,645	15,956	49,264
Cost of natural gas marketing activities	21,512	28,780	19,810	30,482	100,584
Cost of oil and gas well drilling	564	246	749	949	2,508
Exploration expense	2,678	6,780	5,337	8,756	23,551
General and administrative expense	7,424	6,886	7,513	9,145	30,968
Depreciation, depletion and amortization	13,074	17,429	20,354	19,987	70,844
Total costs and expenses	54,287	71,749	66,408	85,275	277,719
Gain on sale of leaseholds	-	25,600	-	7,691	33,291
Income from operations	3,625	29,796	9,867	17,519	60,807
Interest income	1,143	454	462	603	2,662
Interest expense	(831)	(1,450)	(2,544)	(4,454)	(9,279)
Income before income taxes	3,937	28,800	7,785	13,668	54,190
Income taxes	1,436	10,749	3,326	5,470	20,981
Net income	$ 2,501	$ 18,051	$ 4,459	$ 8,198	$ 33,209
Earnings per common share:					
Basic	$ 0.17	$ 1.22	$ 0.30	$ 0.56	$ 2.25
Diluted	$ 0.17	$ 1.21	$ 0.30	$ 0.55	$ 2.24
Weighted average common and common equivalent shares outstanding:					

Basic	14,726	14,740	14,757	14,758	14,744
Diluted	14,854	14,860	14,827	14,859	14,841

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1	Charged to Costs and Expenses	Deductions	Ending Balance December 31
		(in thousands)		
2008:				
Allowance for doubtful accounts (a)	$ 357	$ 180	$ -	$ 537
Valuation allowance for unproved oil and gas properties (b)	$ 2,365	$ 12,798	$ 2,293	$ 12,870
2007:				
Allowance for doubtful accounts (a)	$ 415	$ 50	$ 108	$ 357
Valuation allowance for unproved oil and gas properties (b)	$ 596	$ 2,183	$ 414	$ 2,365
2006:				
Allowance for doubtful accounts (a)	$ 409	$ 7	$ 1	$ 415
Valuation allowance for unproved oil and gas properties (b)	$ 33	$ 653	$ 90	$ 596

(a) Deductions represent the write-off of accounts receivable deemed uncollectible.
(b) Deductions represent amortization of expired or abandoned unproved oil and gas properties.