PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 09, 2007

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

**FORM 10-Q**

S Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
**For the quarterly period ended September 30, 2007**

**OR**

£ Transition Report Pursuant to Section 13 of 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**

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 S No £

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

Large accelerated filer £ Accelerated filer S Non-accelerated filer £

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes £ No S

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: –
14,902,762 shares of the Company's Common Stock ($.01 par value) were outstanding as of October 31, 2007.

PETROLEUM DEVELOPMENT CORPORATION

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**PART I - FINANCIAL INFORMATION**
**Item 1. Financial Statements *(unaudited)***

**PETROLEUM DEVELOPMENT CORPORATION**
Condensed Consolidated Balance Sheets
*(in thousands, except share data)*

| | September 30, 2007 | December 31, 2006* |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 28,612 | $ 194,326 |
| Restricted cash - current | 14,810 | 519 |
| Accounts receivable, net | 45,199 | 42,600 |
| Accounts receivable - affiliates | 10,288 | 9,235 |
| Inventories | 5,794 | 3,345 |
| Fair value of derivatives | 16,403 | 15,012 |
| Other current assets | 20,440 | 5,977 |
| Total current assets | 141,546 | 271,014 |
| Properties and equipment, net | 782,667 | 394,217 |
| Restricted cash - long term | 1,272 | 192,451 |
| Other assets | 8,266 | 26,605 |
| Total assets | $ 933,751 | $ 884,287 |
| | | |
| Liabilities and shareholders' equity | | |
| Current liabilities: | | |
| Accounts payable | $ 99,663 | $ 67,675 |
| Short term debt | - | 20,000 |
| Production tax liability | 12,224 | 11,497 |
| Other accrued expenses | 7,725 | 9,685 |
| Accounts payable - affiliates | 28,035 | 7,595 |
| Deferred gain on sale of leaseholds | - | 8,000 |
| Federal and state income taxes payable | 2,512 | 28,698 |
| Fair value of derivatives | 2,773 | 2,545 |
| Advances for future drilling contracts | 2,199 | 54,772 |
| Funds held for future distribution | 43,955 | 31,367 |
| Total current liabilities | 199,086 | 241,834 |
| Long-term debt | 172,000 | 117,000 |
| Deferred gain on sale of leaseholds | - | 17,600 |
| Other liabilities | 21,222 | 19,400 |
| Deferred income taxes | 135,680 | 116,393 |
| Asset retirement obligation | 18,148 | 11,916 |
| Total liabilities | 546,136 | 524,143 |
| | | |
| Commitments and contingencies | | |
| Minority interest in consolidated limited liability company | 776 | - |
| | | |
| Shareholders' equity: | | |
| Common stock, shares issued: 14,908,656 in 2007 and 14,834,871 in 2006 | 149 | 148 |

| | | |
|---|---|---|
| Additional paid-in capital | 2,052 | 64 |
| Retained earnings | 384,847 | 360,102 |
| Treasury shares, at cost: 5,531 in 2007 and 4,706 in 2006 | (209) | (170) |
| Total shareholders' equity | 386,839 | 360,144 |
| Total liabilities and shareholders' equity | $ 933,751 | $ 884,287 |

**Derived from audited 2006 balance sheet.*

*See accompanying notes to condensed consolidated financial statements.*

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

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 *Revised** | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 *Revised** |
|---|---|---|---|---|
| Revenues: | | | | |
| Oil and gas sales | $ 44,437 | $ 30,577 | $ 117,699 | $ 86,901 |
| Sales from natural gas marketing activities | 19,934 | 30,374 | 71,845 | 101,445 |
| Oil and gas well drilling operations | 1,573 | 2,659 | 7,342 | 11,682 |
| Well operations and pipeline income | 2,092 | 2,536 | 6,682 | 7,312 |
| Oil and gas price risk management, net | 6,345 | 2,707 | 4,442 | 9,002 |
| Other | 1,894 | 1,964 | 2,122 | 1,988 |
| Total revenues | 76,275 | 70,817 | 210,132 | 218,330 |
| | | | | |
| Costs and expenses: | | | | |
| Oil and gas production and well operations cost | 12,645 | 8,584 | 33,308 | 22,363 |
| Cost of natural gas marketing activities | 19,810 | 29,988 | 70,102 | 100,239 |
| Cost of oil and gas well drilling operations | 749 | 3,838 | 1,559 | 11,328 |
| Exploration expense | 5,337 | 2,180 | 14,795 | 5,286 |
| General and administrative expense | 7,513 | 5,357 | 21,823 | 14,178 |
| Depreciation, depletion and amortization | 20,354 | 8,300 | 50,857 | 22,492 |
| Total costs and expenses | 66,408 | 58,247 | 192,444 | 175,886 |
| | | | | |
| Gain on sale of leaseholds | - | 328,000 | 25,600 | 328,000 |
| | | | | |
| Income from operations | 9,867 | 340,570 | 43,288 | 370,444 |
| Interest income | 462 | 3,475 | 2,059 | 4,216 |
| Interest expense | (2,544) | (366) | (4,825) | (1,154) |
| | | | | |
| Income before income taxes | 7,785 | 343,679 | 40,522 | 373,506 |
| Income taxes | 3,326 | 132,795 | 15,511 | 143,697 |
| Net income | $ 4,459 | $ 210,884 | $ 25,011 | $ 229,809 |
| | | | | |
| Earnings per common share: | | | | |
| Basic | $ 0.30 | $ 13.39 | $ 1.70 | $ 14.39 |
| Diluted | $ 0.30 | $ 13.33 | $ 1.68 | $ 14.32 |
| Weighted average common shares outstanding: | | | | |
| Basic | 14,757 | 15,750 | 14,739 | 15,973 |
| Diluted | 14,827 | 15,824 | 14,845 | 16,048 |

**See Note 1.*

*See accompanying notes to condensed consolidated financial statements.*

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**PETROLEUM DEVELOPMENT CORPORATION**
Condensed Consolidated Statements of Cash Flows
*(unaudited, in thousands)*

| | Nine Months Ended September 30, 2007 | 2006 *Revised** |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income | $ 25,011 | $ 229,809 |
| Adjustments to net income to reconcile to cash used in operating activities | | |
| Deferred income taxes | 14,833 | 112,407 |
| Depreciation, depletion and amortization | 50,857 | 22,491 |
| Amortization of debt issuance costs | 280 | 89 |
| Accretion of asset retirement obligation | 712 | 380 |
| Exploratory dry hole costs | 969 | 2,486 |
| Gain from sale of assets | (1) | (328,000) |
| Gain from sale of leaseholds | (25,600) | (64) |
| Expired and abandoned leases | 1,246 | 24 |
| Stock-based compensation | 1,652 | 1,101 |
| Unrealized gain on derivative transactions | (1,256) | (7,592) |
| Excess tax benefits from stock-based compensation | (500) | - |
| Changes in assets and liabilities related to operations: | | |
| Increase in current assets | (34,879) | (2,906) |
| Decrease (increase) in other assets | 220 | (179) |
| Decrease in current liabilities | (68,302) | (44,970) |
| Increase in other liabilities | 1,958 | 3,613 |
| Net cash used in operating activities | (32,800) | (11,311) |
| Cash flows from investing activities: | | |
| Capital expenditures | (158,727) | (133,612) |
| Acquisitions | (201,594) | - |
| Decrease (increase) in restricted cash for property acquisition | 191,178 | (300,000) |
| Proceeds from sale of assets | 2 | 353,617 |
| Proceeds from sale of leases to partnerships | 682 | 1,184 |
| Net cash used in investing activities | (168,459) | (78,811) |
| Cash flows from financing activities: | | |
| Proceeds from debt | 238,000 | 232,000 |
| Repayment of debt | (203,000) | (171,000) |
| Payment of debt issuance costs | (591) | (160) |
| Proceeds from exercise of stock options | 182 | 31 |
| Excess tax benefits from stock-based compensation | 500 | - |
| Minority interest investment | 800 | - |
| Purchase of treasury stock | (346) | (52,639) |
| Net cash provided by financing activities | 35,545 | 8,232 |

| | | | | |
|---|---|---|---|---|
| Net decrease in cash and cash equivalents | | (165,714) | | (81,890) |
| Cash and cash equivalents, beginning of period | | 194,326 | | 90,110 |
| Cash and cash equivalents, end of period | $ | 28,612 | $ | 8,220 |

**See Note 1.*

*See accompanying notes to condensed consolidated financial statements.*

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**Petroleum Development Corporation**
Notes to Condensed Consolidated Financial Statements
September 30, 2007
*(unaudited)*

## 1. GENERAL

Petroleum Development Corporation ("PDC"), together with our consolidated entities (the "Company"), is an independent energy company engaged primarily 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 primarily through exploration and development activities, the acquisition of producing oil and natural gas wells and the expansion of our natural gas marketing activities.

The accompanying interim condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest (see Note 6). All material intercompany accounts and transactions have been eliminated in consolidation. Minority interest in earnings and ownership has been recorded for the percentage of the LLC we do not own for each of the applicable periods. We account for our investment in interests in oil and natural gas limited partnerships under the proportionate consolidation method. Accordingly, our condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships is eliminated.

The accompanying interim condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission ("SEC"). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. In our opinion, the accompanying interim condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly our financial position, results of operations and cash flows for the periods presented. The interim results of operations for the nine months ended September 30, 2007, and the interim cash flows for the same interim period, are not necessarily indicative of the results to be expected for the full year or any other future period.

The accompanying interim condensed consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on May 23, 2007 ("2006 Form 10-K").

### Items Affecting Comparability

Reclassifications have been made to the income statement data presented for the three and nine months ended September 30, 2006, both to conform to the current year presentation and to correct the prior period presentation. These reclassifications had no impact on reported net earnings, earnings per share, shareholders' equity or total net cash flows for the related periods. Oil and gas price risk management gains of $2.7 million and $9 million for the three and nine months ended September 30, 2006, respectively, have been reclassified from non-operating gains to a component of revenues. These reclassifications and all other reclassifications are reflected in the revised amounts for the three and nine months ended September 30, 2006.

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As described in Note 1 to the Consolidated Financial Statements included in our 2006 Form 10-K, during the fourth quarter of 2006, we adopted SEC Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. In accordance with SAB No. 108, we adjusted our opening financial position for 2006 by the cumulative effect of immaterial prior period misstatements. In connection with the adoption of SAB No. 108, we determined that certain similar immaterial errors were included in the results of operations for each of the first three quarters of 2006, and as a result, the data presented in Note 19, Quarterly Financial Data, to the Consolidated Financial Statements of the 2006 Form 10-K and included herein, reflect the correction of those immaterial misstatements.

The following table presents our unaudited income statements for the three month and nine month periods ended September 30, 2006, as previously presented in our Form 10-Q for the related period, adjusted to reflect reclassifications to conform to current presentation and to correct previous presentation, and as revised to reflect the correction of immaterial prior period misstatements.

| | Three Months Ended September 30, 2006 | | | Nine Months Ended September 30, 2006 | | |
|---|---|---|---|---|---|---|
| | Originally Reported | Reclassified (1) | Revised (2) | Originally Reported | Reclassified (1) | Revised (2) |
| | *(in thousands, except per share data)* | | | | | |
| Revenues: | | | | | | |
| Oil and gas sales | $ 29,663 | $ 29,663 | $ 30,577 | $ 86,139 | $ 86,138 | $ 86,901 |
| Sales from natural gas marketing activities | 30,374 | 30,374 | 30,374 | 101,445 | 101,445 | 101,445 |
| Oil and gas well drilling operations | 2,659 | 2,659 | 2,659 | 11,682 | 11,682 | 11,682 |
| Well operations and pipeline income | 2,530 | 2,530 | 2,536 | 7,306 | 7,306 | 7,312 |
| Oil and gas price risk management, net | - | 2,912 | 2,707 | - | 8,714 | 9,002 |
| Other | 1,964 | 1,964 | 1,964 | 1,986 | 1,988 | 1,988 |
| Total revenues | 67,190 | 70,102 | 70,817 | 208,558 | 217,273 | 218,330 |
| | | | | | | |
| Costs and expenses: | | | | | | |
| Oil and gas production and well operations cost | 9,961 | 8,762 | 8,584 | 23,627 | 22,793 | 22,363 |
| Cost of natural gas marketing activities | 29,883 | 29,883 | 29,988 | 100,121 | 100,120 | 100,239 |
| Cost of oil and gas well drilling operations | 4,257 | 4,311 | 3,838 | 11,888 | 11,551 | 11,328 |
| Exploration expense | 940 | 1,749 | 2,180 | 3,735 | 4,569 | 5,286 |
| General and administrative expense | 4,423 | 4,759 | 5,357 | 13,070 | 13,407 | 14,178 |
| Depreciation, depletion and amortization | 8,322 | 8,322 | 8,300 | 22,554 | 22,555 | 22,492 |
| | 57,786 | 57,786 | 58,247 | 174,995 | 174,995 | 175,886 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total costs and expenses | | | | | | |
| Gain on sale of leaseholds | 328,000 | 328,000 | 328,000 | 328,000 | 328,000 | 328,000 |
| Income from operations | 337,404 | 340,316 | 340,570 | 361,563 | 370,278 | 370,444 |
| Interest income | 3,427 | 3,427 | 3,475 | 4,159 | 4,158 | 4,216 |
| Interest expense | (34) | (34) | (366) | (232) | (232) | (1,154) |
| Oil and gas price risk management, net | 2,912 | - | - | 8,714 | - | - |
| Income before income taxes | 343,709 | 343,709 | 343,679 | 374,204 | 374,204 | 373,506 |
| Income taxes | 132,795 | 132,795 | 132,795 | 143,943 | 143,943 | 143,697 |
| Net income | $ 210,914 | $ 210,914 | $ 210,884 | $ 230,261 | $ 230,261 | $ 229,809 |
| Basic earnings per common share | $ 13.44 | $ 13.44 | $ 13.39 | $ 14.47 | $ 14.47 | $ 14.39 |
| Diluted earnings per share | $ 13.38 | $ 13.38 | $ 13.33 | $ 14.40 | $ 14.40 | $ 14.32 |

(1) *As previously reported in the corresponding Form 10-Q, reclassified to conform to current year presentation and to correct previous presentation.*

(2) *Reflects the impact of certain immaterial errors on the results originally reported in 2006.*

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The reclassifications and revisions discussed above have no impact on the condensed consolidated balance sheets presented herein, nor do they result in changes to the net decrease in cash and cash equivalents previously presented in the Form 10-Q for the nine months ended September 30, 2006. However, certain line items within cash flows from operating activities and one line item within cash flow from investing activities for the nine months ended September 30, 2006, have been adjusted herein to reflect the impact of the income statement revisions. Revised line items are as follows:

| | Nine Months Ended September 30, 2006 | |
|---|---|---|
| | Originally Reported | Revised (1) |
| Certain statement of cash flow line items: | *(in thousands)* | |
| Net income | $ 230,261 | $ 229,809 |
| Deferred income taxes | 112,486 | 112,407 |
| Depreciation, depletion and amortization | 22,554 | 22,491 |
| Exploratory dry hole cost | 1,769 | 2,486 |
| Unrealized gain on derivative transactions | (7,305) | (7,592) |
| Increase in current assets | (3,038) | (2,906) |
| Decrease in other current liabilities | (43,396) | (44,970) |
| Increase in other liabilities | 3,412 | 3,613 |
| Net cash used in operating activities | (9,906) | (11,311) |
| Capital expenditures | (135,017) | (133,612) |
| Net cash used in investing activities | (80,216) | (78,811) |
| Net decrease in cash and cash equivalents | (81,890) | (81,890) |

(1) *Reflects the impact of certain immaterial errors on the results originally reported in 2006.*

## 2. RECENT ACCOUNTING STANDARDS

### Recently Adopted Accounting Standards

In June 2006, the Financial Accounting Standards Board ("FASB") issued Emerging Issues Task Force ("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 Accounting Principles Board ("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 impact on the accompanying condensed 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 FASB Interpretation ("FIN") No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109*, which prescribes a comprehensive model for accounting for uncertainty in tax positions.  FIN No. 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service ("IRS"), based on the technical merits of the position.  The provisions of FIN No. 48 became effective for us on 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 for further discussion).

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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 of 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 impact on the accompanying condensed consolidated financial statements.

**Recently Issued Accounting Standards**

In September 2006, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 157, *Accounting for Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value within generally accepted accounting principles and expands required disclosure about fair value measurements. SFAS No. 157 does not expand the use of fair value in any new circumstances. The provisions of SFAS No. 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are evaluating the impact that this new standard will have, if any, on our consolidated financial statements when adopted in 2008.

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 are evaluating the impact that SFAS No. 159 will have, if any, in our consolidated financial statements when it is adopted in 2008.

In April 2007, the FASB issued FSP FIN No. 39-1, *Amendment of FASB Interpretation No. 39* ("FIN No. 39-1"), to amend certain portions of Interpretation 39. FIN No. 39-1 replaces the terms "conditional contracts" and "exchange contracts" in Interpretation 39 with the term "derivative instruments" as defined in Statement 133. FIN No. 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 No. 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. We are evaluating the impact that FIN No. 39-1 will have, if any, on our consolidated financial statements when adopted in 2008.

## 3. 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 like-kind exchange ("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.

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*EXCO Properties.* On January 5, 2007, we completed the purchase of producing properties and undeveloped drilling locations and acreage in the Wattenberg Field area 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. 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 are currently operated by us. The wells are located primarily in the Appalachian Basin and Michigan.

The following table presents the adjusted purchase price for each of the acquisitions described above as of September 30, 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 |

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

| | EXCO | Partnerships |
|---|---|---|
| | *(in thousands)* | |
| Current assets acquired | $ 91 | $ - |
| Proved oil and gas properties | 117,425 | 46,870 |
| Unproved oil and gas properties | 14,960 | 13,273 |
| Asset retirement obligation | (748) | (3,495) |
| Other liabilities assumed | (1,513) | - |
| Preliminary 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. The purchase price allocations are preliminary, subject to fair value appraisals and evaluations of the assets acquired. These amounts are subject to change prior to the completion of the final purchase price allocation as additional information becomes available and is assessed by us.

*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***

*Unioil*. 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 our wholly owned subsidiary, 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. We paid $18.6 million, including $0.4 million of direct acquisition costs, for 100% of Unioil's outstanding common stock.

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The assessment of the fair values of oil and gas properties acquired was based primarily on projections of expected future net cash flows, discounted to present value. The preliminary allocation of acquisition cost included $6.8 million in goodwill, which was re-allocated to properties and equipment in the first quarter of 2007 as part of our ongoing process of finalizing the preliminary allocation of the purchase price. As a result of this reclassification, the deferred tax liabilities increased and property and equipment increased. This increase was approximately $4.2 million. The purchase price allocation is preliminary, subject to completing the evaluation of proved and unproved oil and gas properties. These amounts are subject to change prior to the completion of the final purchase price allocation as additional information becomes available and is assessed by us.

*Other.* 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. The purchase price allocation is preliminary, subject to completing the evaluation of proved and unproved oil and gas properties. These amounts are subject to change prior to the completion of the final purchase price allocation as additional information becomes available and is assessed by us.

***Pro Forma Financial Information***

The results of operations for all of the above acquisitions have been included in the condensed consolidated financial statements from the dates of acquisition. The pro forma effect of the inclusion of the results of operations for all of the above acquisitions, individually and in the aggregate, in our condensed consolidated statement of income for the nine months ended September 30, 2007, was not material.

The following unaudited pro forma financial information presents a summary of our consolidated results of operations for the three and nine months ended September 30, 2006, assuming the acquisitions of the EXCO properties and our sponsored partnerships 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.

| | September 30, 2006 | |
|---|---|---|
| | Three Months Ended | Nine Months Ended |
| | *(in thousands, except per share data)* | |
| Total revenues | $ 77,130 | $ 238,750 |
| Net income | 211,691 | 234,058 |
| Earnings per common share: | | |
| Basic | $ 13.44 | $ 14.65 |
| Diluted | $ 13.38 | $ 14.58 |

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

**4. RESTRICTED CASH**

In July 2006, we established a trust in the amount of $300 million with a qualified intermediary in conjunction with the sale of undeveloped leaseholds and corresponding LKE agreement. As of December 31, 2006, $300 million remained in the trust, with $109 million reflected in cash and cash equivalents as a current asset in the condensed consolidated balance sheet and the remaining $191.5 million reflected as restricted cash - long term. In January 2007, $188.9 million of the $191.5 million was utilized in the acquisition of oil and gas properties qualifying for LKE treatment, which are included in oil and gas properties at September 30, 2007, with the unused amount being used in general operating activities.

In June 2007, we funded an escrow account in the amount of $14.1 million for amounts due to the limited partners of our sponsored drilling partnerships as a result of us over withholding estimated production taxes in years prior to 2007, which is included, along with interest earned of $0.2 million, in restricted cash, current, in the condensed consolidated balance sheet as of September 30, 2007.

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## 5. INCOME TAXES

Effective January 1, 2007, we adopted FIN No. 48, which clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements in accordance with FASB Statement 109, *Accounting for Income Taxes*, by prescribing the minimum recognition threshold and measurement attribute a tax position taken or expected to be taken on a tax return is required to meet before being recognized in the financial statements. We recorded a $0.3 million reduction in retained earnings at January 1, 2007, to recognize the cumulative effect of the adoption of FIN No. 48. This amount represents the total amount of interest on unrecognized tax benefits as of the date of adoption. As of January 1, 2007, unrecognized tax benefits amounted to $1 million and are included in federal and state income taxes payable in the condensed consolidated balance sheet. None of the unrecognized tax benefits relate to a position that, if recognized, will impact our effective tax rate. While the income or expense to which the uncertain tax position relates is variable in nature, as of September 30, 2007, we do not expect the unrecognized tax position to significantly increase or decrease in the next twelve months.

As a matter of accounting policy, we recognize interest and penalties related to unrecognized tax benefits, if applicable, in income tax expense in the condensed consolidated statements of income. During the three and nine months ended September 30, 2007, there was no material change to the amount of interest recorded on unrecognized tax benefits. Accruals for interest on unrecognized tax benefits totaled $0.3 million at September 30, 2007, which are included in federal and state income taxes payable in the condensed consolidated balance sheet. There were no accruals for penalties on unrecognized tax benefits at January 1, 2007, or during the three and nine months ended September 30, 2007.

At September 30, 2007, our federal income tax returns were closed through the 2002 tax year and there are no outstanding tax controversies with any taxing authorities regarding these prior tax years. Subsequently, during the third quarter of 2007, we reached a final settlement with the IRS regarding the examination of our 2003 and 2004 tax years. The examination was officially concluded and the revenue agent's report was signed on July 31, 2007, resulting in no material impact to the current year financial statements or to any of our uncertain tax positions.

State and other income tax returns are generally subject to examination for a period of three to five years after the filing of the respective returns. The state impact of any amended federal returns, whether or not pursuant to IRS examination changes or pursuant to our voluntary changes, remains subject to examination by various states for a period of up to one year after formal notification of such amendments to the states. We currently have no state income tax returns in the process of examination or administrative appeal. We are currently preparing amended 2003 and 2004 state income tax returns to reflect the IRS examination changes.

We filed our 2004 state income tax returns in June 2007 and our 2005 federal and state income tax returns in September 2007. These filing dates begin the applicable statute of limitations for examination and adjustment. Our 2006 federal and state income tax returns were filed timely, by the extended due dates, in September 2007 and October 2007, respectively.

## 6. 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 the Chief Executive Officer of the Company, 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 included in the accompanying condensed consolidated statement of income as an offset to depreciation, depletion and amortization expense.

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**7. EARNINGS PER SHARE**

A reconciliation of basic and diluted earnings per common share is as follows:

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| | *(in thousands, except per share data)* | | | |
| Weighted average common shares outstanding | 14,757 | 15,750 | 14,739 | 15,973 |
| Dilutive effect of share-based compensation: (1) | | | | |
| Unamortized portion of restricted stock | 35 | 20 | 41 | 16 |
| Stock options | 30 | 54 | 60 | 59 |
| Non employee director deferred compensation | 5 | - | 5 | - |
| Weighted average common and common equivalent shares outstanding | 14,827 | 15,824 | 14,845 | 16,048 |
| | | | | |
| Net income | $ 4,459 | $ 210,884 | $ 25,011 | $ 229,809 |
| Basic earnings per common share | $ 0.30 | $ 13.39 | $ 1.70 | $ 14.39 |
| Diluted earnings per common share | $ 0.30 | $ 13.33 | $ 1.68 | $ 14.32 |

(1) *Excludes the effect of average anti-dilutive common share equivalents related to out-of-the-money options and unvested restricted shares of 48,500 and 9,673 for the three and nine months ended September 30, 2007, respectively, and 22,180 and 12,003 for the three and nine months ended September 30, 2006.*

**8. STOCK-BASED COMPENSATION**

We maintain long-term equity compensation plans for our directors, officers and certain key employees. In accordance with the plans, awards have been granted in the form of stock options, restricted stock and market based shares.

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

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| | *(in thousands)* | | | |
| Total share-based compensation expense | $ 628 | $ 435 | $ 1,652 | $ 1,101 |
| Income tax benefit | (242) | (168) | (637) | (424) |
| | | | | |
| Net income impact | $ 386 | $ 267 | $ 1,015 | $ 677 |

**Stock Option Awards.** We granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. We did not grant any stock option awards for the nine months ended September 30, 2007. The weighted average fair value per share of the options granted during the nine months ended September 30, 2006, as computed using the Black-Scholes pricing model, was $19.65. The weighted average assumptions used to estimate these fair values were as follows:

| | Nine Months Ended September 30, 2006 |
|---|---|
| Expected Volatility | 39.5% |
| Expected term (in years) | 5.9 |
| Risk-free interest rate | 4.3% |

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 declare or pay cash dividends in the foreseeable future.

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The following table provides a summary of our stock option award activity for the nine months ended September 30, 2007:

| | Number of Shares Underlying Options | Weighted Average Exercise Price Per Share | Weighted Average Remaining Contractual Term *(in years)* | Aggregate Intrinsic Value *(in millions)* |
|---|---|---|---|---|
| Outstanding at December 31, 2006 | 89,567 | $ 21.36 | 5.6 | $ 2.0 |
| Exercised | (38,000) | 4.81 | | 1.7 |
| Outstanding at September 30, 2007 | 51,567 | 33.55 | 6.6 | 0.6 |
| Vested and expected to vest at September 30, 2007 | 47,808 | 32.65 | 6.5 | 0.6 |
| Exercisable at September 30, 2007 | 24,529 | 23.85 | 4.9 | 0.5 |

Total unrecognized stock-based compensation cost related to stock options, net of estimated forfeitures, was $0.3 million as of September 30, 2007. This cost is expected to be recognized over a weighted average period of 2.1 years.

**Restricted and Market Based Awards.** During the nine months ended September 30, 2007, we awarded 61,609 restricted shares with a weighted average grant date fair value of $47.69 per share and 31,972 market based shares of restricted stock with a weighted average grant date fair value of $36.07 per share. The fair value of the restricted awards and market based shares is amortized ratably over the requisite service period, primarily over four years for restricted awards and 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. The weighted average grant date fair value of each market based share was computed using the Monte Carlo pricing model and the following weighted average assumptions:

| | |
|---|---|
| Expected term of award | 3 years |
| Risk-free interest rate | 4.7% |
| Volatility | 44.0% |

The following table provides a summary of our restricted and market based share awards activity for the nine months ended September 30, 2007:

| | Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested at December 31, 2006 | 131,730 | $ 39.87 |
| Granted | 93,581 | 43.72 |
| Vested | (28,934) | 38.10 |
| Forfeited | (2,139) | 40.07 |
| Non-vested at September 30, 2007 | 194,238 | 41.98 |

The total compensation cost related to non-vested and expected to vest restricted awards not yet recognized as of September 30, 2007, for both restricted and market based awards was $5.6 million.  The cost is expected to be recognized over a weighted-average period of 2.8 years.

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## 9. PROPERTIES AND EQUIPMENT

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| | *(in thousands)* | |
| Properties and equipment, net: | | |
| Oil and gas properties (successful efforts method of accounting) | | |
| Proved | $ 869,700 | $ 473,451 |
| Unproved | 53,200 | 27,055 |
| Total oil and gas properties | 922,900 | 500,506 |
| Pipelines and related facilities [(1)] | 20,605 | 12,673 |
| Transportation and other equipment [(2)] | 18,928 | 7,870 |
| Land and buildings | 11,915 | 11,620 |
| Construction in progress [(3)] | 2,449 | 4,801 |
| | 976,797 | 537,470 |
| Accumulated depreciation, depletion and amortization ("DD&A") | (194,130) | (143,253) |
| | $ 782,667 | $ 394,217 |

*(1) At September 30, 2007, includes $3.2 million related to additional compressors and upgraded pipeline facilities in the Piceance Basin production operations, which was placed in service in second and third quarter of 2007.*

*(2) At September 30, 2007, includes $5.1 million related to the Garden Gulch road, which was placed in service in May 2007. At December 31, 2006, construction in progress included $3.6 million related to the Garden Gulch road.*

*(3) At September 30, 2007, includes costs primarily related to a new integrated oil and gas financial software system.*

**Suspended Well Costs**

As of December 31, 2006, we had capitalized one exploratory well awaiting the determination of proved reserves with costs of $0.8 million. During the quarter ended June 30, 2007, the well was determined to be dry and expensed in the same quarter. As of September 30, 2007, there were no exploratory wells awaiting the determination of proved reserves.

## 10. ASSET RETIREMENT OBLIGATION

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

| | Amount *(in thousands)* |
|---|---|
| Beginning balance at December 31, 2006 | $ 11,966 |
| Obligations assumed with development activities and acquisitions | 5,541 |
| Accretion expense | 712 |
| Obligations discharged with disposed properties and asset retirements | (21) |
| Ending balance at September 30, 2007 | $ 18,198 |

Approximately $0.1 million of our asset retirement obligation is classified as short term and included in other accrued expenses as of September 30, 2007, and December 31, 2006.

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**11. LONG-TERM DEBT**

We entered into a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas with a maximum commitment of $200 million, dated as of November 4, 2005, subject to and secured by required levels of natural gas and oil reserves. We are required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at 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 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. 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.

Effective August 9, 2007, we entered into the first amendment to our credit facility adding a new bank, Wachovia Bank, N.A., and increasing our aggregate commitments from $150 million to $200 million, all of which is fully activated. The amendment also waived our working capital covenant until the earlier of (i) a debt or equity transaction resulting in net proceeds to us of at least $200 million or (ii) July 1, 2008. Under the amended agreement the ABR rate was increased by 0.375% as long as the waiver of the working capital covenant is in effect.

As of September 30, 2007, the outstanding balance under the credit facility was $172 million compared to $117 million, excluding the overline note discussed below, as of December 31, 2006. Any amounts outstanding under the credit facility are secured by substantially all of our properties. The outstanding balance at September 30, 2007, was subject to an adjusted LIBOR of 7.5625%. We were in compliance with all covenants as of September 30, 2007.

See Note 18 regarding a second amendment to our credit facility and the subsequent addition of two new banks.

On December 19, 2006, we executed, pursuant to our credit facility, an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.8% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January 2007.

**12. SUPPLEMENTAL CASH FLOW DISCLOSURE**

| | Nine Months Ended September 30, 2007 | 2006 |
|---|---|---|
| | *(in thousands)* | |
| Cash paid for: | | |
| Interest | $ 6,991 | $ 1,398 |
| Income taxes | 43,615 | 46,478 |
| Non-cash investing activities: | | |
| Change in deferred tax liability resulting from reallocation of acquisition purchase price | 4,188 | - |
| Changes in accounts payable - affiliates related to acquisition of partnerships | 668 | - |
| Changes in accounts payable related to purchases of properties and equipment | 34,150 | 2,412 |
| Changes in accounts payable-affiliates related to investment in drilling partnership | 18,712 | - |

**13. COMMITMENTS AND CONTINGENCIES**

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, for our own benefit, to develop specified acreage in the Wattenberg Field area 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 September 30, 2007, our total capital expenditures pursuant to the agreement were $26.1 million, resulting in a maximum potential obligation of $1.2 million.

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In August 2007, we completed the 2007 drilling partnership offering, *Rockies Region 2007 Limited Partnership*, and received subscriptions of approximately $90 million. At closing, we, as managing general partner, were obligated to make a cash capital contribution to the program of $38.7 million for our general partner interest, representing approximately 43% of the aggregate subscriptions received for the program. We funded $20 million of the total $38.7 million commitment at closing and recorded the remaining $18.7 million liability as a component of accounts payable - affiliates, a current liability, on the accompanying condensed consolidated balance sheet as of September 30, 2007. We subsequently paid the $18.7 million capital contribution to the partnership on October 31, 2007. Drilling for the new program commenced during the third quarter of 2007, with drilling and completion operations scheduled to continue through the first and second quarters of 2008. No assurance can be made that we will continue to receive this level of funding from any future programs.

In order to secure the services for two drilling rigs, we made commitments to the drilling contractor, which call for a minimum commitment of $12,500 per day for a specified amount of time if we do not use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $40,680 per day for a specified amount of time for daily use of the drilling rigs. Commitments for these two separate contracts expire in July 2009 and May 2010. As of September 30, 2007, we had an outstanding minimum commitment for $6.7 million and an outstanding maximum commitment for $26.4 million.

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 natural gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2006 or through the third quarter of 2007.

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 potential repurchase obligation as of September 30, 2007, was approximately $6.6 million. During the first nine months of 2007, we paid $0.9 million for the repurchase of partnership units.

As managing general partner of 33 partnerships, we are liable for any potential casualty losses in excess of the partnership assets and insurance. Our management believes that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

In connection with the sale of undeveloped leaseholds in July 2006, we, pursuant to the purchase and sale agreement, 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 undrilled well for a total contingent obligation of $25.6 million, which was reflected as a deferred gain on sale of leaseholds in the accompanying condensed consolidated balance sheet at December 31, 2006. On May 31, 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 quarter ended June 30, 2007.

Pursuant to the above letter agreement, we are obligated to drill six wells on specifically identified acreage. These wells will be drilled on the unaffiliated party's leasehold for its benefit and at its cost. In addition, the unaffiliated party will return 160 acres of leasehold property acquired from us pursuant to the purchase and sale agreement. As of the date of this report, we have drilled four of the six wells; we anticipate drilling the remaining two wells during the fourth quarter of 2007.

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We were party to an exploration agreement with an unaffiliated party. The agreement required us to drill a minimum of 25 exploratory wells through June 30, 2007. For each well we failed to drill prior to June 30, 2007, we were required to pay liquidated damages equal to $125,000 per undrilled well. After drilling three exploratory wells, we determined, based on drilling results, not to drill the remaining 22 exploratory wells. During the quarter ended June 30, 2007, we recorded charges to exploration expense for the liquidated damages of $2.7 million related to the 22 undrilled wells and $1.1 million related to the write-off of the carrying value of the acreage resulting from the abandonment of the project. The accrued liquidated damages were paid in full in September 2007.

**14. SHAREHOLDERS' RIGHTS AGREEMENT**

On September 11, 2007, we entered into a Rights Agreement (the “Rights Agreement”), with Transfer Online, Inc., as rights agent. The Rights Agreement is designed to improve the ability of our Board of Directors ("Board") to protect the interest of our shareholders in the event of an unsolicited takeover attempt. Our Board declared a dividend of one right ("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 of the Company) 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.

**15. LEGAL PROCEEDINGS**

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

*Royalty Payments.* On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against us in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells we operated in the State of Colorado (the "Droegemueller Action"). The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for the alleged underpayment of royalties we made to the plaintiff pursuant to leases. We moved the case to Federal Court on June 28, 2007, and on July 10, 2007, we filed our answer and affirmative defenses. A scheduling order has not been issued at this time and no discovery has taken place. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, we are unable to predict the ultimate outcome of this suit at this time.

**16. BUSINESS SEGMENTS**

Our operating activities are divided into four major segments: oil and gas sales, natural gas marketing, drilling and development, and well operations and pipeline income. We own an interest in approximately 3,500 wells from which we sell the oil and natural gas production from our working interests in the wells. Included in the oil and gas sales segment are the operating results of the acquisitions described in Note 3. A wholly-owned subsidiary, Riley Natural Gas ("RNG"), engages in the marketing of natural gas to commercial and industrial end-users. We drill natural gas wells for our sponsored drilling partnerships and retain an interest in each well. We charge our sponsored partnerships and other third parties competitive industry rates for well operations and natural gas gathering. All material inter-company accounts and transactions between segments have been eliminated.

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Segment information for the three and nine months ended September 30, 2007 and 2006, is presented below.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 *Revised | 2007 | 2006 *Revised |
| | (in thousands) | | | |
| Revenues: | | | | |
| Oil and gas sales [1] | $ 50,782 | $ 33,284 | $ 122,141 | $ 95,903 |
| Natural gas marketing | 19,934 | 30,374 | 71,845 | 101,445 |
| Drilling and development | 1,573 | 2,659 | 7,342 | 11,682 |
| Well operations and pipeline income | 2,092 | 2,536 | 6,682 | 7,312 |
| Unallocated amounts | 1,894 | 1,964 | 2,122 | 1,988 |
| Total | $ 76,275 | $ 70,817 | $ 210,132 | $ 218,330 |
| | | | | |
| Segment income (loss) before income taxes: | | | | |
| Oil and gas sales [2] | $ 14,367 | $ 15,878 | $ 28,727 | $ 51,352 |
| Natural gas marketing | 333 | 558 | 2,357 | 1,682 |
| Drilling and development | 824 | (1,179) | 5,783 | 355 |
| Well operations and pipeline income [3] | 486 | 776 | 1,900 | 1,807 |
| Unallocated amounts [4] | (8,225) | 327,646 | 1,755 | 318,310 |
| Total | $ 7,785 | $ 343,679 | $ 40,522 | $ 373,506 |

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| | (in thousands) | |
| Segment assets: | | |
| Oil and gas sales | $ 728,101 | $ 394,952 |
| Natural gas marketing | 31,705 | 39,899 |
| Drilling and development [5] | 53,499 | 87,746 |
| Well operations and pipeline income | 36,954 | 28,895 |
| Unallocated amounts [6] | 83,492 | 332,795 |
| Total | $ 933,751 | $ 884,287 |

** See Note 1.*

*(1) Includes oil and gas price risk management, net.*

*(2) Includes exploration expense; DD&A expense of $19.3 million and $48.2 million for the three and nine months ended September 30, 2007, and $7.7 million and $20.8 million for the three and nine months ended September 30, 2006, respectively.*

*(3) Includes DD&A expense of $0.7 million and $1.9 million for the three and nine months ended September 30, 2007 and $0.5 and $1.4 million as of September 30, 2006, respectively.*

*(4)*

*Includes general and administrative expense; interest income; interest expense; DD&A expense of $0.3 million and $0.8 million for the three and nine months ended September 30, 2007, and $0.1 million and $0.3 million for the three and nine months ended September 30, 2006, respectively; the nine months ended September 30, 2007, and the three and nine months ended September 30, 2006, include gains on sale of leasehold of $25.6 million and $328 million, respectively.*

(5) *The December 31, 2006, amount includes cash of $50.7 million for partnership drilling activities, which was substantially utilized by September 30, 2007.*

(6) *The December 31, 2006, amount includes designated cash of $191.5 million, which was utilized in LKE property transactions during the first quarter of 2007 and included in the oil and gas sales segment as of September 30, 2007.*

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**17. DERIVATIVE FINANCIAL INSTRUMENTS**

We utilize commodity based derivative instruments to manage a portion of our exposure to price risk from oil and natural gas sales and marketing activities. Our policy prohibits the use of oil and natural gas future and option contracts for speculative purposes. These instruments consist of New York Mercantile Exchange ("NYMEX") traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for Northeast Colorado ("NECO") production and Colorado Interstate Gas Index ("CIG") based contracts for other Colorado production. We purchase puts and participating collars for our production and affiliate partnerships' production to protect against possible price instability in future periods while retaining much of the benefit 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. As a result, 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.

The following tables summarize the open derivative option and purchase and sales contracts for PDC and RNG as of September 30, 2007.

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

| Commodity | Type | Quantity Gas-MMbtu Oil-Barrels | Weighted Average Price | Total Contract Amount | Fair Value |
|---|---|---|---|---|---|
| Total Positions as of September 30, 2007 | | | | | |
| Natural Gas | Cash Settled Option Sales | 16,300,000 | $ 10.70 | $ 174,373 | $ (2,287) |
| Natural Gas | Cash Settled Option Purchases | 21,160,000 | 5.69 | 120,497 | 16,005 |
| Oil | Cash Settled Option Purchases | 30,000 | 50.00 | 1,500 | (32) |
| | | | | | $ 13,686 |
| Positions maturing in 12 months following September 30, 2007 | | | | | |
| Natural Gas | Cash Settled Option Sales | 14,580,000 | $ 10.70 | $ 156,008 | $ (1,728) |
| Natural Gas | Cash Settled Option Purchases | 19,440,000 | 5.69 | 110,567 | 14,652 |
| Oil | Cash Settled Option Purchases | 30,000 | 50.00 | 1,500 | (32) |
| | | | | | $ 12,892 |

The maximum term for the derivative contracts listed above is 13 months.

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**Riley Natural Gas**
Open Derivative Positions
*(dollars in thousands, except average price data)*

| Commodity | Type | Quantity Gas-MMbtu | Weighted Average Price | Total Contract Amount | Fair Value |
|---|---|---|---|---|---|
| Total Positions as of September 30, 2007 | | | | | |
| Natural Gas | Cash Settled Futures/Swaps Purchases | 243,525 | $ 7.36 | $ 1,793 | $ (97) |
| Natural Gas | Cash Settled Futures/Swaps Sales | 1,567,000 | 8.71 | 13,642 | 1,699 |
| Natural Gas | Cash Settled Option Purchases | 60,000 | 5.50 | 330 | 1 |
| Natural Gas | Cash Settled Option Sales | 30,000 | 10.10 | 303 | (1) |
| Natural Gas | Physical Purchases | 1,567,000 | 8.58 | 13,437 | (966) |
| Natural Gas | Physical Sales | 123,583 | 9.36 | 1,157 | 151 |
| | | | | | $ 787 |
| Positions maturing in 12 months following September 30, 2007 | | | | | |
| Natural Gas | Cash Settled Futures/Swaps Purchases | 240,825 | $ 7.36 | $ 1,772 | $ (97) |
| Natural Gas | Cash Settled Futures/Swaps Sales | 1,344,000 | 8.70 | 11,691 | 1,631 |
| Natural Gas | Cash Settled Option Purchases | 60,000 | 5.50 | 330 | 1 |
| Natural Gas | Cash Settled Option Sales | 30,000 | 10.10 | 303 | (1) |
| Natural Gas | Physical Purchases | 1,344,000 | 8.52 | 11,452 | (945) |
| Natural Gas | Physical Sales | 120,883 | 9.38 | 1,133 | 150 |
| | | | | | $ 739 |

The maximum term for the derivative contracts listed above is 26 months.

In addition to including the gross assets and liabilities related to our share of oil and natural gas production, the above tables and the accompanying condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into on behalf of the affiliate partnerships as the managing general partner. The accompanying condensed consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of $5.8 million as of September 30, 2007, and $7.5 million as of December 31, 2006.

We are required to maintain margin deposits with brokers for outstanding futures contracts. Restricted cash, current, of $0.5 million was on deposit as of September 30, 2007, and December 31, 2006.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, we are exposed to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates repayment risk. We minimize the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults in 2006 or during the nine months ended September 30, 2007.

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

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| | *(in thousands)* | |
| Classification in the Condensed Consolidated Balance Sheets: | | |
| Fair value of derivatives - current asset | $ 16,403 | $ 15,012 |
| Other assets - long-term asset | 1,424 | 1,146 |
| | 17,827 | 16,158 |
| | | |
| Fair value of derivatives - current liability | 2,773 | 2,545 |
| Other liabilities - long-term liability | 581 | - |
| | 3,354 | 2,545 |
| Net fair value of commodity based derivatives | $ 14,473 | $ 13,613 |

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The following tables identify the changes in the fair value of commodity based derivatives as reflected in the condensed consolidated statements of income.

| | Three Months Ended September 30, | | | | |
|---|---|---|---|---|---|
| | 2007 | | 2006 | | |
| Statement of income line item | Realized | Unrealized | Realized | Unrealized | |
| | *(in thousands, gains/(losses))* | | | | |
| Oil and gas price risk management, net | $ 2,491 | $ 3,854 | $ 52 | $ 2,655 | (1) |
| Sales from natural gas marketing activities | 1,477 | 12 | 909 | 1,826 | |
| Cost of natural gas marketing activities | (108) | (87) | (376) | (1,477) | |

| | Nine Months Ended September 30, | | | | |
|---|---|---|---|---|---|
| | 2007 | | 2006 | | |
| Statement of income line item | Realized | Unrealized | Realized | Unrealized | |
| | *(in thousands, gains/(losses))* | | | | |
| Oil and gas price risk management, net | $ 3,098 | $ 1,344 | $ 1,503 | $ 7,499 | (1) |
| Sales from natural gas marketing activities | 2,805 | (1,256) | 1,694 | 12,439 | |
| Cost of natural gas marketing activities | (331) | 1,168 | (1,422) | (12,346) | |

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*(1)* *Revised, see Note 1.*

**18. SUBSEQUENT EVENTS**

*Second Amendment to Amended and Restated Credit Agreement*. As of October 16, 2007, we entered into a second amendment to our credit facility with JPMorgan, BNP Paribas and Wachovia Bank, N.A. (see Note 11). The amendment (1) increases the aggregate commitments from $200 million to $275 million and allows, with further bank commitment, for a maximum possible credit facility of $400 million; (2) includes three additional lenders: Bank of Oklahoma, Morgan Stanley Bank and Guaranty Bank, FSB (collectively with JP Morgan, BNP Paribas and Wachovia Bank, N.A., ("the banks")); (3) modifies the waiver of our non-compliance with the working capital covenant received pursuant to the first amendment to extend it to October 1, 2008; and (4) modifies the security to require an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties.

As of November 6, 2007, the Company and the banks, through execution of assignment and assumption agreements and related promissory note agreements, added two additional banks, Royal Bank of Canada and The Royal Bank of Scotland, plc to the credit facility.

*Purchase of Natural Gas Wells*. On October 30, 2007, with an effective date of October 1, 2007, we purchased from an unrelated party a majority working interest in 762 natural gas wells located in southwestern Pennsylvania for approximately $53 million. The acquisition includes our estimate of approximately 47 Bcfe net proved reserves and associated pipelines, equipment, real estate and undeveloped acreage.

*Oil Derivative Transaction*. On October 30, 2007, we entered into NYMEX-based crude swaps for the calendar year 2008 at $84.20/bbl for 29,000 bbls per month. This represents approximately 44% of our current Wattenberg oil production per month.

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## Item 2. 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-Q, should be read in conjunction with the condensed consolidated financial statements and related notes to condensed consolidated financial statements included elsewhere in this report.

### Disclosure Regarding Forward Looking Statements

This Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are our estimates of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in successfully drilling productive wells and in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, our ability to sell our produced natural gas and oil and the prices we receive for production, our ability to comply with changes in federal, state, local, and other laws and regulations, including environmental policies, and the operating hazards attendant to the oil and gas business. In particular, careful consideration should be given to cautionary statements made in this Form 10-Q, our Annual Report on Form 10-K for the year ended December 31, 2006, and our other SEC filings and public disclosures. We undertake no duty to update or revise these forward-looking statements.

### Non-GAAP Financial Measure

The following management's discussion and analysis refers to "adjusted cash flow from operations," a non-GAAP financial measure. Adjusted cash flow from operations is the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flow from operations separately, as we believe it can often be a better way to present, discuss and analyze changes in operating trends in our business caused by changes in production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during that year. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations caused primarily by significant changes in commodity prices. Adjusted cash flow from operations is not a measure of financial performance under GAAP and it should be considered in addition to, not as a substitute for, cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP.

### Management Overview

### Net Income

The following table presents net income and diluted earnings per share for the three and nine months ended September 30, 2007 and 2006.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | *(dollars in thousands, except per share data)* | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Net income | $ | 4,459 | $ | 210,884 | $ | 25,011 | $ | 229,809 |
| Diluted earnings per share | $ | 0.30 | $ | 13.33 | $ | 1.68 | $ | 14.32 |

Net income for the three and nine months ended September 30, 2007, declined significantly due to last year's $328 million pretax gain associated with the July 2006 sale of a leasehold to an unrelated party (see Gain on Sale of Leaseholds below).

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**Revenues**

Revenues for the three and nine months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| | *(in thousands)* | | | |
| Revenues: | | | | |
| Oil and gas sales | $ 44,437 | $ 30,577 | $ 117,699 | $ 86,901 |
| Sales from natural gas marketing activities | 19,934 | 30,374 | 71,845 | 101,445 |
| Oil and gas well drilling operations | 1,573 | 2,659 | 7,342 | 11,682 |
| Well operations and pipeline income | 2,092 | 2,536 | 6,682 | 7,312 |
| Oil and gas price risk management, net | 6,345 | 2,707 | 4,442 | 9,002 |
| Other | 1,894 | 1,964 | 2,122 | 1,988 |
| Total revenues | $ 76,275 | $ 70,817 | $ 210,132 | $ 218,330 |

Total revenues for the quarter were up $5.5 million or 7.7%, despite a 24.1% decline in natural gas prices. The increase in revenue for the quarter was primarily due to a 78.9% increase in our oil and natural gas production, offset in part by a 34.4% decrease in sales from natural gas marketing activities.

While production volumes were up 60.2% for the first nine months of 2007, total revenues for the period were down $8.2 million or 3.8% from the comparable prior year period. Oil and natural gas sales increased $30.8 million as a result of the increase in production of 60.2% although commodity prices declined 15.4%. The decrease in total revenues was primarily due to decreases in natural gas sales from marketing activities of $29.6 million and oil and gas price risk management, net of $4.6 million. Our gas marketing division 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. The decreases in both sales from natural gas marketing activities and oil and gas price risk management, net are a result of a comparison to large unrealized derivative gains during the nine months ended September 30, 2006, a consequence of the decline in natural gas prices from the extremely high natural gas prices at the end of 2005 driven by the 2005 active hurricane season in the Gulf.

**Costs and Expenses**

Costs and expenses for the three and nine months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| | *(in thousands)* | | | |
| Costs and expenses: | | | | |
| Oil and gas production and well operations cost | $ 12,645 | $ 8,584 | $ 33,308 | $ 22,363 |
| Cost of natural gas marketing activities | 19,810 | 29,988 | 70,102 | 100,239 |
| Cost of oil and gas well drilling operations | 749 | 3,838 | 1,559 | 11,328 |
| Exploration expense | 5,337 | 2,180 | 14,795 | 5,286 |
| General and administrative expense | 7,513 | 5,357 | 21,823 | 14,178 |
| Depreciation, depletion and amortization | 20,354 | 8,300 | 50,857 | 22,492 |
| Total costs and expenses | $ 66,408 | $ 58,247 | $ 192,444 | $ 175,886 |

The increase in total costs and expenses for the comparable three and nine month periods was a reflection of our growth over the past year, which was funded primarily by the reinvestment of the proceeds from the 2006 sale of undeveloped leasehold of $353.6 million into productive operating properties. Due to the acquisitions and the significant number of new wells drilled for our own account and placed in service during 2007, we have substantially increased production, resulting in higher costs and expenses.

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The increases in oil and gas production costs and well operation costs and depreciation, depletion and amortization ("DD&A") expense for the comparable three and nine month periods directly reflect the growth we are currently experiencing. The increase in exploration expense for the comparable periods was due to the increased exploratory department costs, and for the nine months, liquidated damages from an exploration agreement and the subsequent lease abandonment. The decline in natural gas marketing costs corresponds to the decline in sales from natural gas marketing activities as referenced above. The costs of oil and gas well drilling decreased as a result of our change in the type of drilling contract we offer.

**Adjusted Cash Flow from Operations**

The following table presents a reconciliation of adjusted cash flow from operations for the three and nine months ended September 30, 2007 and 2006.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | *(in thousands)* | | | |
| Net cash provided by/used in operating activities | $ 43,585 | $ 2,632 | $ (32,800) | $ (11,311) |
| Changes in assets and liabilities related to operations | (11,947) | (2,497) | 101,003 | 44,442 |
| Adjusted cash flow from operations | $ 31,638 | $ 135 | $ 68,203 | $ 33,131 |

While commodity prices declined and expenses increased for the three and nine month periods in 2007, adjusted cash flow from operations increased significantly from the prior year periods. Total costs and expenses increased 14% and 9.4% for the three and nine months ended September 30, 2007, respectively, compared to the same prior year periods, in large part due to the increased production. As explained in results of operations, DD&A expense, a non-cash expense, increased $12.1 million and $28.4 million, for the three and nine months ended September 30, 2007, respectively, compared to the same prior year periods. The increases were largely due to increased production levels, substantial investment through acquisitions of proved producing and non producing mineral interests, and investment in wells and related equipment and facilities. Other significant changes in expense components are discussed hereafter.

**Results of Operations**

**Three Months Ended September 30, 2007, Compared to Three Months Ended September 30, 2006**

**Revenues**

**Oil and Gas Sales**

Revenues for oil and gas sales for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Oil and gas sales | $ 44,437 | $ 30,577 | $ 13,860 | 45.3% |

The increase in oil and gas sales for the comparable three months was primarily due to increased volumes of natural gas and oil of 78.9%, partially offset by lower average sales prices of natural gas. The increased volume of natural gas and oil contributed $19.6 million to oil and gas sales, while the decline in prices reduced oil and gas sales by $5.7 million for the net increase of $13.9 million for the third quarter of 2007 compared to the same prior year period. The increase in natural gas and oil volumes was the result of our increased investment in oil and gas properties, primarily the fourth quarter 2006 and first quarter 2007 acquisitions and the significantly increased number of wells we drilled for our own account over the past year. The oil and gas sales generated during the third quarter of 2007 from the acquisitions made in the fourth quarter 2006 and first quarter 2007 and their subsequent development were $11.5 million.

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***Oil and Natural Gas Production.*** Oil and natural gas production by area of operation along with average sales price (excluding derivative gains/losses) for the three months is presented below.

| | Three Months Ended September 30, | | | | | | Change | |
|---|---|---|---|---|---|---|---|---|
| | | 2007 | | 2006 | | Amount | | Percent |
| Natural Gas (Mcf) | | | | | | | | |
| Appalachian Basin | | 606,165 | | 327,499 | | 278,666 | | 85.1% |
| Michigan Basin | | 421,909 | | 355,624 | | 66,285 | | 18.6% |
| Rocky Mountains | | 5,284,103 | | 2,620,421 | | 2,663,682 | | 101.7% |
| Total | | 6,312,177 | | 3,303,544 | | 3,008,633 | | 91.1% |
| | | | | | | | | |
| *Average Sales Price* | *$* | *4.67* | *$* | *6.15* | *$* | *(1.48)* | | *-24.1%* |
| | | | | | | | | |
| Oil (Bbls) | | | | | | | | |
| Appalachian Basin | | 602 | | 441 | | 161 | | 36.5% |
| Michigan Basin | | 1,003 | | 1,281 | | (278) | | -21.7% |
| Rocky Mountains | | 233,130 | | 166,821 | | 66,309 | | 39.7% |
| Total | | 234,735 | | 168,543 | | 66,192 | | 39.3% |
| | | | | | | | | |
| *Average Sales Price* | *$* | *63.67* | *$* | *60.93* | *$* | *2.74* | | *4.5%* |
| | | | | | | | | |
| Natural Gas Equivalents (Mcfe)* | | | | | | | | |
| Appalachian Basin | | 609,777 | | 330,145 | | 279,632 | | 84.7% |
| Michigan Basin | | 427,927 | | 363,310 | | 64,617 | | 17.8% |
| Rocky Mountains | | 6,682,883 | | 3,621,347 | | 3,061,536 | | 84.5% |
| Total | | 7,720,587 | | 4,314,802 | | 3,405,785 | | 78.9% |
| | | | | | | | | |
| *Average Sales Price* | *$* | *5.76* | *$* | *7.09* | *$* | *(1.33)* | | *-18.8%* |

**One Bbl of oil is equal to the energy equivalent of six Mcf of natural gas.*

The production generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development was 1.8 Bcfe. This represents approximately half of the total 78.9% increase in production for the three months ended September 30, 2007, compared to the same period last year.

Late in the second quarter of 2007, we placed into service the upgraded Garden Gulch pipeline and compressor facility, which serves a majority of our wells in the Piceance Basin. This upgrade included two new natural gas compressors, with a third compressor added in the third quarter, and pipeline facility enhancements. The upgrade and enhancements have allowed us to substantially increase our production capacity from the wells feeding this facility from the time of its start-up in late June.

***Oil and Natural Gas Pricing.*** Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on our financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region as shown in the graph below. The combination of increased drilling activity and the lack of local markets can result in a local oversupply situation from time to time. These periodic oversupply situations vary in their length of time and may affect the volume of natural gas and oil that we can sell and the price at which we can sell our natural gas and oil. There are a number of different pipelines in various stages of construction by other companies which will help to maintain a balance between supply and demand. Like most other producers in the region, we rely on major interstate pipeline companies to construct these facilities causing the timing and availability of these facilities to be outside of our control (see Natural Gas Pricing and Pipeline Capacity in Liquidity and Capital Resources).

*Rocky Mountain Region Pricing*. Although our weighted average price for natural gas for the three months ended September 30, 2007, was $4.67 per Mcf, 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 may include some gas sold at the Colorado Interstate Gas Index ("CIG"). The CIG Index is currently much less than the price received for natural gas produced in the eastern regions, which is New York Mercantile Exchange ("NYMEX") based. The natural gas price in the eastern regions, where 16.3% of our total production for the quarter was produced, was $5.79 per Mcf compared to our Rocky Mountain Region price per Mcf of $4.14. The Rocky Mountain Region contributed 83.7% of our natural gas for the quarter and is where we anticipate a majority of our future production increases to occur. During the current quarter, through our derivative activities, we realized a benefit from the floors put in place on our production in the Rocky Mountain Region. We received $3.5 million in proceeds (gross, excluding the cost of floors) from our derivative instruments during the current quarter or $0.65 per Mcf, which helped to offset the lower prices we received for our Rocky Mountain Region natural gas. We report our activities from derivative transactions under the oil and gas price risk management, net line item in the accompanying condensed consolidated statements of income.

The graph below identifies the actual NYMEX and CIG natural gas prices by month from January 2006 through November 2007 and the forward curve for natural gas prices through March 2009 as of November 1, 2007. The forecasted prices in the graph have been derived from the sources indicated and represent, in our opinion, a reasonable view of the possible movement of the CIG and NYMEX natural gas prices over the next 16 months. However, because the prices given in the graph represent forecasts of future matters and are subject to future events which we cannot predict, we can give no assurance that these forecasted prices will be as they are presented in the graph. An investor should therefore not rely on these forecasted prices in making an investment decision regarding our stock.

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**Source: Derived from various sources including FutureSource, Inside FERC's Gas Market Report and ClearPort Trading.*

While the above graph shows a large differential between current NYMEX and CIG pricing, the gap as shown above is expected to close this winter and has begun to narrow since September 30, 2007. As of November 1, 2007 the price differential between NYMEX and CIG for 2008 has narrowed to $1.48 from $3.19 average for the third quarter. Although 83.7% of this quarter's production came from the Rocky Mountain Region, the Rocky Mountain natural gas and oil pricing is based upon other indices along with CIG.

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The table below identifies the basis of our natural gas and oil pricing on a sales volume basis for the quarter ended September 30, 2007. It further outlines that 42.3% of our natural gas sales are derived from the CIG index. In the third quarter of 2007, we realized considerably higher prices associated with our non CIG volumes.

Energy Market Exposure
as of September 30, 2007

| Area | Pricing Basis | Commodity | Percent of Oil and Gas Sales |
|---|---|---|---|
| Piceance/Wattenberg | Rocky Mountain (CIG, et. al.) | Gas | 42.3% |
| Colorado/North Dakota | NYMEX | Oil | 21.6% |
| NECO | Mid Continent (Panhandle Eastern) | Gas | 14.3% |
| Appalachian | NYMEX | Gas | 12.4% |
| Michigan | Mich-Con/NYMEX | Gas | 5.9% |
| Wattenberg | Colorado Liquids | Gas | 3.0% |
| Other | Other | Gas/Oil | 0.5% |
| | | | 100.0% |

***Production Curtailments.*** With the drop in October 2007 Rocky Mountain natural gas prices, we curtailed our production in the Piceance and NECO areas of operations for October 2007. Total net curtailment was approximately 350,000 Mcf for the month of October 2007. We ceased the curtailment and returned production to normal levels in November 2007 due to an increase in the November 2007 prices.

**Natural Gas Marketing Activities**

Revenues from natural gas marketing activities for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, 2007 | 2006 | Change Amount | Percent |
|---|---|---|---|---|
| | *(dollars in thousands)* | | | |
| Sales from natural gas marketing activities | $ 19,934 | $ 30,374 | $ (10,440) | -34.4% |

The decrease in sales from natural gas marketing activities for the comparable three month periods was due to lower prices and lower volumes sold and a $1.8 million decrease in unrealized gains on derivative transactions.

**Oil and Gas Well Drilling Operations**

Revenues from drilling operations for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, 2007 | 2006 | Change Amount | Percent |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| | *(dollars in thousands)* | | | |
| Oil and gas well drilling operations | $ 1,573 | $ 2,659 | $ (1,086) | -40.8% |

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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 three months ended September 30, 2006, oil and gas well drilling operations segment includes a $1.2 million loss from footage-based contracts with no material similar loss being recognized for the three months ended September 30, 2007.

**Well Operations and Pipeline Income**

Revenues from well operations and pipeline income for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Well operations and pipeline income | $ 2,092 | $ 2,536 | $ (444) | -17.5% |

In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships, which resulted in the three month period to period decrease in well operations and pipeline income. Having acquired 423 net wells pursuant to the acquisition, we no longer receive 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 drilling program partnerships as well as third parties.

**Oil and Gas Price Risk Management, Net**

Oil and gas price risk management, net for the three months ended September 30, 2007 and 2006, is presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Oil and gas price risk management, net | $ 6,345 | $ 2,707 | $ 3,638 | 134.4% |

For the three months ended September 30, 2007, we recorded realized and unrealized gains of $2.5 million and $3.8 million, respectively, compared to realized and unrealized gains of $0.1 million and $2.6 million, respectively, for the same prior year period. The unrealized gains for the third quarter of 2006 were a result of declines from June 30, 2006, to September 30, 2006, in both the CIG and NYMEX markets, which increased the value of our floors. Also, many additional positions were added in late September 2006, prior to quarter end. The significant decline in NYMEX, CIG and Panhandle pricing from June 30, 2007, to September 30, 2007, increased the value of our floors, resulting in the unrealized gains recorded in the current year quarter. The significant decline in the CIG market during the current year quarter also resulted in substantial realized gains, which offset in part the lower natural gas prices for the current year quarter. As prices decline, our derivative portfolio, which is comprised predominantly of floors, increases in value, resulting in gains.

Oil and gas price risk management, net is comprised of realized 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 marketing activities, which are included in sales from and cost of natural gas marketing activities.

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***Oil and Natural Gas Derivative Activities.*** Because of the uncertainty surrounding natural gas and oil prices, we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through December 2008, we have in place a series of floors and ceilings on a portion of the natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor, the counterparty pays us. During the three months ended September 30, 2007, our average monthly natural gas and oil volumes sold were 2.1 Bcf and 78,000 Bbls.

The positions in effect as of October 1, 2007, on our share of production by area are shown in the following table.

| | | Floors | | Ceilings | |
|---|---|---|---|---|---|
| Month Set | Contract Term | Monthly Quantity Gas-Mmbtu Oil-Barrels | Contract Price | Monthly Quantity Gas-Mmbtu Oil-Barrels | Contract Price |
| Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin) | | | | | |
| Feb-06 | Oct-07 | 44,000 | $ 5.50 | - | $ - |
| Sep-06 | Oct-07 | 194,500 | 4.50 | - | - |
| Dec-06 | Nov 2007 - Mar 2008 | 100,000 | 5.25 | - | - |
| Jan-07 | Nov 2007 - Mar 2008 | 100,000 | 5.25 | 100,000 | 9.80 |
| May-07 | Apr 2008 - Oct 2008 | 197,250 | 5.50 | 197,250 | 10.35 |
| NYMEX Based Derivatives - (Appalachian and Michigan Basins) | | | | | |
| Feb-06 | Oct-07 | 85,000 | $ 7.00 | - | $ - |
| Feb-06 | Oct-07 | 85,000 | 7.50 | 85,000 | 10.83 |
| Sep-06 | Oct-07 | 85,000 | 6.25 | - | - |
| Jan-07 | Oct-07 | 85,000 | 5.25 | - | - |
| Dec-06 | Nov 2007 - Mar 2008 | 144,500 | 7.00 | - | - |
| Jan-07 | Nov 2007 - Mar 2008 | 144,500 | 7.00 | 144,500 | 13.70 |
| Jan-07 | Apr 2008 - Oct 2008 | 144,500 | 6.50 | 144,500 | 10.80 |
| May-07 | Apr 2008 - Oct 2008 | 120,000 | 7.00 | 120,000 | 13.00 |
| Panhandle Based Derivatives (NECO) | | | | | |
| Feb-06 | Oct-07 | 60,000 | $ 6.00 | - | $ - |
| Feb-06 | Oct-07 | 60,000 | 6.50 | 60,000 | 9.80 |
| Jan-07 | Oct-07 | 90,000 | 4.50 | - | - |
| Dec-06 | Nov 2007 - Mar 2008 | 70,000 | 5.75 | - | - |
| Jan-07 | Nov 2007 - Mar 2008 | 90,000 | 6.00 | 90,000 | 11.25 |
| Jan-07 | | 90,000 | 5.50 | 90,000 | 9.85 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Apr 2008 - Oct 2008 | | | | | | |
| Jun-07 | Apr 2008 - Oct 2008 | 90,000 | | 6.00 | 90,000 | | 11.25 |
| | | | | | | | |
| Colorado Interstate Gas (CIG) Based Derivatives (DJ Basin) | | | | | | | |
| Jan-07 | Oct-07 | 221,000 | $ | 4.00 | - | $ | - |
| Jan-07 | Nov 2007 - Mar 2008 | 120,000 | | 5.25 | 120,000 | | 9.80 |
| May-07 | Apr 2008 - Oct 2008 | 306,000 | | 5.50 | 306,000 | | 10.35 |
| | | | | | | | |
| Oil - NYMEX Based (Wattenberg/ND) | | | | | | | |
| Sep-06 | Oct-07 | 12,350 | | 50.00 | - | $ | - |

On October 30, 2007, we entered into NYMEX-based crude swaps for calendar year 2008 at $84.20/bbl for 29,000 bbls per month.  This represents approximately 44% of our current Wattenberg oil production per month.

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**Costs and Expenses**

**Oil and Gas Production and Well Operations Costs**

Oil and gas production and well operations costs for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | *(dollars in thousands, except per Mcfe)* | | | |
| Oil and gas production and well operations cost | $ 12,645 | $ 8,584 | $ 4,061 | 47.3% |
| *Per Mcfe* | *1.64* | *1.99* | *(0.35)* | *-17.6%* |

The increase in oil and gas production and well operations costs for the three months was primarily attributable to the 78.9% increase in production volumes and the increased number of wells and pipeline systems we operate as a result of our fourth quarter 2006 and first quarter 2007 acquisitions.  Lifting cost per Mcfe decreased slightly from $1.34 to $1.31 per Mcfe.

In additional to increased production, the increase in costs is also attributable to increased production and engineering staff, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers associated with the fourth quarter 2006 and the first quarter 2007 acquisitions and general oil field services inflation pressures.

**Natural Gas Marketing Activities**

Cost of natural gas marketing activities for the three months ended September 30, 2007 and 2006, is presented below.

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | *(dollars in thousands)* | | | |
| Cost of natural gas marketing activities | $ 19,810 | $ 29,988 | $ (10,178) | -33.9% |

The decrease in the costs of natural gas marketing activities for the comparable three month periods was due to lower prices and lower volumes purchased and a $1.4 million decrease in unrealized losses on derivative transactions from $1.5 million for the 2006 period to $0.1 million for the 2007 period.

**Oil and Gas Well Drilling Operations**

Cost of oil and gas well drilling operations for the three months ended September 30, 2007 and 2006, is presented below.

| | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | *(dollars in thousands)* | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Cost of oil and gas well drilling operations | $ | 749 | $ | 3,838 | $ | (3,089) | -80.5% |

The decrease in cost of oil and gas well drilling operations was due to our revenue generating operational change, and the corresponding accounting treatment, from footage-based drilling arrangements to cost-plus drilling arrangements; see our revenue discussion of oil and gas well drilling operations.

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The completion of the remaining footage-based arrangements, which incurred losses during 2006, improved the profitability of the drilling segment from a loss of $1.2 million for the three months ended September 30, 2006, to a profit of $0.8 million for the three months ended September 30, 2007.

**Exploration Expense**

Exploration expense for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Exploration expense | $ 5,337 | $ 2,180 | $ 3,157 | 144.8% |

The increase in exploration expense for the current year quarter included $1.9 million related to increased exploration department costs, $0.8 million related to three exploratory wells determined to be dry and expensed during the quarter and $0.6 million related to a drilling rig commitment.

**General and Administrative Expense**

General and administrative expense for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands, except per Mcfe)* | | | |
| General and administrative expense | $ 7,513 | $ 5,357 | $ 2,156 | 40.2% |
| *Per Mcfe* | *0.97* | *1.24* | *(0.27)* | *-21.8%* |

The increase in general and administrative expense for the three months was primarily due to increased costs related to compliance with the various provisions of Sarbanes-Oxley, financial statement audits, legal expenses and accounting assistance from third party consulting services.

General and administrative expense per Mcfe decreased period to period as well as in each of the three consecutive quarterly periods in 2007, with the benefit received from increased production more than offsetting the increase in expenses.

**Depreciation, Depletion and Amortization**

DD&A for the three months ended September 30, 2007 and 2006, is presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands, except per Mcfe)* | | | |
| Depreciation, depletion and amortization | $ 20,354 | $ 8,300 | $ 12,054 | 145.2% |

| | | | | |
|---|---|---|---|---|
| *Per Mcfe* | *2.64* | *1.92* | *0.72* | *37.5%* |

Higher production levels resulted in a $6 million increase in DD&A for the quarter ended September 30, 2007, compared to the same period a year ago. The remaining period to period change is primarily related to the acquisitions of proved mineral interest and the addition of wells, related equipment and facilities, increasing DD&A by $3.1 million and $2.7 million, respectively.

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**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 ("PSA"), as filed with the Securities and Exchange Commission ("SEC") as Exhibit 10.3 to the Form 10-Q for the period ended September 30, 2006, pursuant to which we recognized a $328 million gain on sale of leasehold in the third quarter of 2006.

**Non-operating Income/Expense**

Non-operating income and expense for the three months ended September 30, 2007 and 2006, are presented below.

| | Three Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Non-operating income (expense): | | | | |
| Interest income | $ 462 | $ 3,475 | $ (3,013) | -86.7% |
| Interest expense | (2,544) | (366) | (2,178) | 595.1% |

The decrease in interest income for the quarter is a result of lower cash balances earning interest compared to the same period last year, primarily due to the $353.6 million in cash proceeds from the sale of undeveloped leaseholds in July 2006. The proceeds were reinvested in oil and gas properties by mid-January 2007. The increase in interest expense for the current year period was due to significantly higher average outstanding balances of our credit facility, offset by capitalized construction period interest of $1 million compared to $0.7 million for the three months ended September 30, 2006, respectively. We utilize our daily cash balances to reduce the line of credit, lowering the costs of interest.

**Provision for Income Taxes**

The effective income tax rate for the provision for income taxes for the three months ended September 30, 2007, was 42.7% compared to 38.6% for the same prior year period. The increase in the tax rate was primarily due to our decision in the third quarter to expense approximately $27 million of intangible drilling costs for tax purposes. This decision eliminates our ability to claim the "domestic production deduction" ("DPD") for the 2007 tax year, thereby increasing our effective income tax rate. However, this decision is projected to result in approximately a $10 million reduction to our current year income tax liability.

**Nine Months Ended September 30, 2007, Compared to Nine Months Ended September 30, 2006**

**Revenues**

**Oil and Gas Sales**

Revenues for oil and gas sales for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Oil and gas sales | $ 117,699 | $ 86,901 | $ 30,798 | 35.4% |

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The increase in oil and gas sales for the comparable nine months was primarily due to increased volumes of natural gas and oil of 60.2%, partially offset by lower average sales prices of natural gas and oil. The increased volume of natural gas and oil contributed $44.2 million to oil and gas sales, while the decline in prices reduced oil and gas sales by $13.4 million for the net increase of $30.7 million from the comparable period. The increase in natural gas and oil volumes was the result of our increased investment in oil and gas properties, primarily the fourth quarter 2006 and first quarter 2007 acquisitions and the significantly increased number of wells drilled for our own account over the past year. The oil and gas sales generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development were $25.4 million.

***Oil and Natural Gas Production.*** Oil and natural gas production by area of operation along with average sales price for the nine months (excluding derivative gains/losses) is presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| Natural Gas (Mcf) | | | | |
| Appalachian Basin | 1,891,153 | 1,108,400 | 782,753 | 70.6% |
| Michigan Basin | 1,263,186 | 1,067,160 | 196,026 | 18.4% |
| Rocky Mountains | 12,334,849 | 7,135,371 | 5,199,478 | 72.9% |
| Total | 15,489,188 | 9,310,931 | 6,178,257 | 66.4% |
| | | | | |
| *Average Sales Price* | *$ 5.20* | *$ 6.27* | *$ (1.07)* | *-17.1%* |
| | | | | |
| Oil (Bbls) | | | | |
| Appalachian Basin | 3,816 | 1,230 | 2,586 | 210.2% |
| Michigan Basin | 2,985 | 3,274 | (289) | -8.8% |
| Rocky Mountains | 659,951 | 470,938 | 189,013 | 40.1% |
| Total | 666,752 | 475,442 | 191,310 | 40.2% |
| | | | | |
| *Average Sales Price* | *$ 55.78* | *$ 60.08* | *$ (4.30)* | *-7.2%* |
| | | | | |
| Natural Gas Equivalents (Mcfe)* | | | | |
| Appalachian Basin | 1,914,049 | 1,115,780 | 798,269 | 71.5% |
| Michigan Basin | 1,281,096 | 1,086,804 | 194,292 | 17.9% |
| Rocky Mountains | 16,294,555 | 9,960,999 | 6,333,556 | 63.6% |
| Total | 19,489,700 | 12,163,583 | 7,326,117 | 60.2% |
| | | | | |
| *Average Sales Price* | *$ 6.04* | *$ 7.14* | *$ (1.10)* | *-15.4%* |

**One Bbl of oil is equal to the energy equivalent of six Mcf of natural gas.*

The production generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development was 3.9 Bcfe. This represents 53% of the total 60.2% increase in production for the nine months ended September 30, 2007, compared to the same period last year.

Late in the second quarter of 2007, we placed into service the upgraded Garden Gulch pipeline and compressor facility, which serves a majority of our wells in the Piceance Basin. This upgrade included two new natural gas compressors, with a third compressor added in the third quarter, and pipeline facility enhancements. The upgrade and enhancements have allowed us to substantially increase our production capacity from wells feeding this facility from the time of its start-up in late June.

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***Oil and Natural Gas Pricing.*** Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on our financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets can entail a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction by other companies which will help to maintain a balance between supply and demand. However, there may be times in which there may be oversupply situations for short or longer terms, which may affect the amount of natural gas or oil that we can sell, and the price at which we sell natural gas or oil. Like most other producers in the region, we rely on major interstate pipeline companies to construct these facilities causing the timing and availability of these facilities to be outside of our control (see Natural Gas Pricing and Pipeline Capacity in Liquidity and Capital Resources).

*Rocky Mountain Region Pricing*. Although our weighted average price for natural gas for the nine months ended September 30, 2007, was $5.20 per Mcf, the price we receive for a majority of the natural gas produced in the Rocky Mountain Region is based on a market basket of prices, including the CIG index. The CIG is currently much less than the price received for natural gas produced in the eastern regions which is NYMEX based. The natural gas price in the eastern regions, where 20.4% of production for the nine months was located, was $6.48 per Mcf compared to the Rocky Mountain Region price per Mcf of $4.77. The Rocky Mountain Region produced 79.6% of the natural gas for the nine months, and is where the future production increases are scheduled to occur. We benefited during the current nine months through our derivative activities from the floors placed in the Rocky Mountain Region. We received $5.5 million in proceeds (gross, excluding the cost of floors) from our derivative instruments during the first nine months, or $0.44 per Mcf, which helps to offset the lower prices we received for the Rocky Mountain Region natural gas. We report our activities from derivative transactions under the oil and gas price risk management line item on the income statement. See three month discussion and analysis of Oil and Natural Gas Pricing above.

**Natural Gas Marketing Activities**

Revenues from natural gas marketing activities for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | *(dollars in thousands)* | | | |
| Sales from natural gas marketing activities | $ 71,845 | $ 101,445 | $ (29,600) | -29.2% |

The decrease in sales from natural gas marketing activities for the comparable nine month periods was due to lower average price of natural gas sold and lower volumes and a $13.6 million decrease in unrealized gains on derivative transactions from $12.4 million to a $1.2 million unrealized loss in the 2007 period.

**Oil and Gas Well Drilling Operations**

Revenues from drilling operations for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | *(dollars in thousands)* | | | | | | |
| Oil and gas well drilling operations | $ | 7,342 | $ | 11,682 | $ | (4,340) | -37.2% |

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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. The nine months ended September 30, 2006, included a $1.9 million loss from footage-based contracts, with no material amounts being recognized for the nine months ended September 30, 2007.

**Well Operations and Pipeline Income**

Revenues from well operations and pipeline income for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Well operations and pipeline income | $ 6,682 | $ 7,312 | $ (630) | -8.6% |

In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships, which resulted in the nine month period to period decrease in well operations and pipeline income. Having acquired 423 net wells pursuant to the acquisitions, we no longer receive well operation and pipeline 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 the drilling program partnerships as well as third parties.

**Oil and Gas Price Risk Management, Net**

Oil and gas price risk management, net for the nine months ended September 30, 2007 and 2006, is presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Oil and gas price risk management, net | $ 4,442 | $ 9,002 | $ (4,560) | -50.7% |

For the nine months ended September 30, 2007, we recorded realized and unrealized gains of $3.1 million and $1.3 million, respectively, compared to realized and unrealized gains of $1.5 million and $7.5 million, respectively, for the same prior year period. The significant decline of record pricing from December 31, 2005, to September 30, 2006, in both the CIG and NYMEX markets, increased the value of the floors and resulted in large unrealized gains during the first quarter of last year and smaller unrealized gains as the market continued to fall for the second and third quarter ends. The CIG and NYMEX pricing fluctuated from December 31, 2006, to September 30, 2007, with the market pricing increasing from December 31, 2006, to March 31, 2007. The increase resulted in large unrealized losses for the first quarter of this year offset by unrealized gains in the second and third quarters as pricing fell again resulting in the lower unrealized gain recorded in the current nine month period. The significant decline in the CIG market during the current year resulted in the increase in realized gains for the current nine month period compared to the 2006 nine month period. As prices decline, our derivative portfolio, which is comprised predominantly of floors, increases in value, resulting in both realized and unrealized gains.

Oil and gas price risk management, net is comprised of realized 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 marketing activities, which are included in sales from and cost of natural gas marketing activities.

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**Costs and Expenses**

**Oil and Gas Production and Well Operations Costs**

Oil and gas production and well operations costs for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | *(dollars in thousands, except per Mcfe)* | | | |
| Oil and gas production and well operations cost | $ 33,308 | $ 22,363 | $ 10,945 | 48.9% |
| *Per Mcfe* | *1.71* | *1.84* | *(0.13)* | *-7.1%* |

The increase in oil and gas production and well operations costs for the nine months was primarily attributable to the 60.2% increase in production volumes and the increased number of wells and pipeline systems we operate due to the fourth quarter 2006 and first quarter 2007 acquisitions. Lifting cost per Mcfe increased from $1.27 to $1.33 per Mcfe, which was primarily due to well workovers and production enhancements work performed.

In addition to increased production, the increase in cost is also due to additional production and engineering staff, increased maintenance and operating costs of the new pipeline and compressor upgrades and improvements, increased production enhancements and workover costs associated with the fourth quarter 2006 and the first quarter 2007 acquisitions and general oil field services inflation pressures.

**Natural Gas Marketing Activities**

Cost of natural gas marketing activities for the nine months ended September 30, 2007 and 2006, is presented below.

| | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | | *(dollars in thousands)* | | |
| Cost of natural gas marketing activities | $ 70,102 | $ 100,239 | $ (30,137) | -30.1% |

The decrease in costs of natural gas marketing activities for the comparable nine month periods was due to lower prices and a $13.5 million decrease in unrealized losses on derivative transactions from $12.3 million to a $1.2 million unrealized gain for the 2007 period, offset in part by higher volumes of natural gas purchased.

**Oil and Gas Well Drilling Operations**

Cost of oil and gas well drilling operations for the nine months ended September 30, 2007 and 2006, is presented below.

| | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | | *(dollars in thousands)* | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Cost of oil and gas well drilling operations | $ | 1,559 | $ | 11,328 | $ | (9,769) | -86.2% |

The decrease in cost of oil and gas well drilling operations was due to our revenue reporting for the cost-plus drilling arrangements as described above.

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**Exploration Expense**

Exploration expense for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Exploration expense | $ 14,795 | $ 5,286 | $ 9,509 | 179.9% |

Pursuant to an exploration agreement with an unaffiliated party, during the quarter ended June 30, 2007, we abandoned the project and recorded charges to exploration expense for liquidated damages of $2.7 million and $1.1 million related to the write-off of the carrying value of the related acreage. The increase is also attributable to increased payroll and payroll related and other additional exploratory department costs.

**General and Administrative Expense**

General and administrative expense for the nine months ended September 30, 2007 and 2006, are presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands, except per Mcfe)* | | | |
| General and administrative expense | $ 21,823 | $ 14,178 | $ 7,645 | 53.9% |
| *Per Mcfe* | *1.12* | *1.17* | *(0.05)* | *-4.3%* |

The increase in general and administrative expense for the nine months was due to increased costs related to financial statement audits, compliance with the various provisions of Sarbanes-Oxley, payroll and payroll related costs, legal expenses and accounting assistance from third party consulting services.

**Depreciation, Depletion and Amortization**

DD&A for the nine months ended September 30, 2007 and 2006, is presented below.

| | Nine Months Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | Percent |
| | *(dollars in thousands, except per Mcfe)* | | | |
| Depreciation, depletion and amortization | $ 50,857 | $ 22,492 | $ 28,365 | 126.1% |
| *Per Mcfe* | *2.61* | *1.85* | *0.76* | *41.1%* |

Higher production levels resulted in a $13 million increase in DD&A for the nine months ended September 30, 2007, compared to the same period a year ago. The remaining period to period change is primarily related to the acquisitions of proved mineral interests and the addition of wells and related equipment and facilities, increasing DD&A by $8.6 million and $5.9 million, respectively.

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**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 ("PSA"), as filed with the Securities and Exchange Commission ("SEC") as Exhibit 10.3 to the Form 10-Q for the period ended September 30, 2006. Total proceeds from the sale were $353.6 million, of which we recognized $328 million of the gain in the third quarter of 2006. In May 2007, we entered into a letter agreement amending the PSA, relieving us of our obligation, in its entirety, to either drill 16 wells on specifically identified acreage over the next three years, at our cost and our benefit, 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.

**Non-operating Income/Expense**

| | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 | Change Amount | Change Percent |
|---|---|---|---|---|
| | *(dollars in thousands)* | | | |
| Non-operating income (expense): | | | | |
| Interest income | $ 2,059 | $ 4,216 | $ (2,157) | -51.2% |
| Interest expense | (4,825) | (1,154) | (3,671) | 318.1% |

The decrease in interest income for the nine months ended September 30, 2007, was primarily due to higher average cash balances in the prior year period, principally as the result of the $353.6 million cash proceeds from the sale of undeveloped leaseholds during the third quarter of 2006, which were reinvested in oil and gas properties by mid-January 2007. The increase in interest expense was due to significantly higher average outstanding balances of our credit facility, offset in part by capitalized construction period interest of $2.3 million and $1.1 million for the nine months ended September 30, 2007 and 2006, respectively. We utilize daily cash balances to reduce our line of credit to lower the costs of interest.

**Provision for Income Taxes**

The effective income tax rate for the provision for income taxes for the nine months ended September 30, 2007, was 38.3%, relatively unchanged from the same prior year period of 38.5%.

**Liquidity and Capital Resources**

We are conducting and plan to continue historically high levels of exploration, development and acquisition of oil and gas properties. Our business, as with other extractive industries, is a depleting one in which each barrel or Mcf produced must be replaced or our operations, a critical source of our future liquidity, will shrink. Cash investments are continuously required to fund exploration and development projects and acquisitions which are necessary to offset the inherent declines in production and proven reserves as well as to provide for continuing growth. Future success in maintaining and growing reserves and production will be highly dependent on having adequate capital resources available, on our success in both exploration and development activities and on acquiring additional reserves.

We have utilized public and private markets, proceeds from bank borrowings and cash flow from operations for our capital resources and liquidity. To date, our primary use of capital has been for the acquisition and development of oil and gas properties. As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in replacing and growing reserve levels will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our current credit facility, if available, or obtain additional debt or equity financing. Our current credit facility imposes certain restrictions on our ability to obtain additional debt financing. Based upon our current expectations, we believe our liquidity and capital resources will be sufficient for the conduct of our business and operations.

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*Natural Gas Pricing and Pipeline Capacity*

We sell natural gas under contracts based on spot prices or price indices that reflect current market prices for the commodity. As a result, variations in market prices are reflected in the revenue we receive. The price of natural gas has varied substantially over short periods of time in the past, and it is expected that there will be a continuation of that variability in the future. During the first nine months of 2007, prices for natural gas decreased from the last part of 2006 but remained relatively strong, and future expectations as reflected in the NYMEX futures market are for continuing high price levels for the remainder of 2007 and beyond. Strong domestic and international demand for energy and inadequate short term supplies are key drivers of strong prices. High prices could encourage the development of new energy sources and reduced consumption as users find more efficient ways to use energy or substitute other energy forms. High energy prices could also slow global economic growth, further reducing demand. As a result, the energy price environment could change rapidly from current expectations. Reduced natural gas prices would reduce the profitability and cash flow from our natural gas production operations.

Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain region. The combination of increased drilling activity and the lack of local markets could result in a local market oversupply situation from time to time. Such a situation currently exists in the Rocky Mountain region, with production exceeding the local market demand and pipeline capacity to non-local markets. The result, beginning in the second quarter of 2007 and continuing into the fourth quarter of 2007, has been a decrease in the price of Rocky Mountain natural gas compared to the NYMEX price and other markets. We expect this situation to continue until cold weather returns and/or new pipeline capacity for moving gas to non-local markets is placed in service. In particular, the expansion and service resumption of the Rockies Express pipeline is expected to improve the region's pricing relative to other markets. The second of three phases is scheduled to go into service in early 2008. Once the third phase and compression work on the pipeline are complete in 2009, the pipeline capacity is expected to increase by 64% to 1.8 Bcf/per day of natural gas from the region. 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*

Oil prices are at historical record levels and have been high for most of the last few years including 2007. Our oil prices are largely determined by oil prices in the world market. Global supply and demand and geopolitical factors are the key determinants of oil prices. The rapid growth of energy use in developing countries, such as China and India, is driving a rapid increase in worldwide oil consumption. Higher prices could result in reduced consumption and/or increasing supplies that could reduce the current high price levels. Over the past several years, oil has been an increasing part of our production mix. Oil sales accounted for 31.6% of our oil and gas sales during the first nine months of 2007 compared to 32.9% for the same prior year period.

*Oil and Natural Gas Derivative Activities*

Because of the uncertainty surrounding natural gas and oil prices, we use various derivative instruments to mitigate the impact of fluctuations in prices. Through December 2008, we have in place a series of floors and/or ceilings for a portion of our natural gas and oil production. Under these derivative instruments we are guaranteed a realized price at or between the indexed floor and ceiling prices. See the section titled "Oil and Gas Derivative Activities" as discussed in our three-month results of operations for a more detailed analysis of our current derivative positions.

We use derivative investments to lock-in prices for our and our partners' share of production. Actual wellhead prices will vary based on local contract conditions, gathering dynamics and other costs and factors. We record the fair value of our partners' share of outstanding derivative obligations or benefits in accounts receivable or other liabilities as appropriate. Our derivative transactions do not currently qualify for hedge accounting under Statement of Financial Accounting Standard No. 133. Therefore, we record derivative gains and losses, both realized and unrealized, through oil and gas price risk management for our share of production. We are required to mark-to-market the derivative positions at the end of each period and record the adjustment to the consolidated statement of income. This results in profit variability from period to period.

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During the nine months ended September 30, 2007, we recognized oil and gas price risk management gains of $4.4 million compared to gains for the nine months ended September 30, 2006, of $9.0 million.

*Drilling Programs*

In August 2007, we completed the drilling partnership offering, *Rockies Region 2007 Limited Partnership*, and received subscriptions of approximately $90 million. We contributed $38.7 million, which represented 43% of the $90 million of total subscriptions received, for our general partner capital contribution. We funded $20 million of the total $38.7 million commitment at closing and recorded the remaining $18.7 million liability as a component of accounts payable - affiliates on the accompanying condensed consolidated balance sheet as of September 30, 2007. We subsequently paid the $18.7 million capital to the partnership on October 31, 2007. Drilling for the partnership commenced during the third quarter of 2007. Drilling and completion operations are scheduled to continue through the remainder of 2007 and into the first half of 2008. We expect to recognize revenue of approximately $13.2 million in our oil and gas well drilling operations related to this partnership from the inception, August 2007, through the conclusion of the drilling and completion operations. As of September 30, 2007, $1.1 million in revenues has been recognized. No assurance can be made that we will continue to receive this level of funding from any future programs.

Substantially all of our partnership drilling programs provide investors a provision requiring us to purchase a portion of their partnership units upon request. Each purchase provision becomes effective upon the third anniversary of the partnership drilling program’s first cash distribution. The provision stipulates that upon an investor’s purchase demand, subject to our financial ability to do so, we are obligated to purchase a maximum of 10% of the investor’s subscription each year (at a minimum price of four times the most recent 12 months' cash distributions) until their subscription is repaid. The maximum annual required contingent purchase requirement, if requested by the investors, would be approximately $6.6 million. We have adequate liquidity to satisfy this contingent obligation. During the first nine months of 2007, we paid $0.9 million for the requested repurchase of partnership units.

*2007 Capital Budget*

We established a $229 million exploration and development capital budget for 2007. The budget includes our equity contribution to the 2007 partnership and excludes capital for potential acquisitions. We have drilled 264 of the budgeted 375 wells as of September 30, 2007. The majority of the wells were drilled in our Colorado fields. See the table below for wells drilled during the nine months ended September 30, 2007. As of September 30, 2007, we have spent approximately $220 million of the 2007 exploration and development capital budget. With our 2007 partnership contribution already included in the $220 million spent as of September 2007, we do not expect that the continued drilling for the partnership in the fourth quarter of 2007 will have an adverse affect on our liquidity for the remainder of 2007. We continuously evaluate possible acquisitions that would meet our internally established requirements. During 2007, we have consummated announced acquisitions totaling approximately $188.9 million and contributing 195.1 Bcfe of proved reserves to our portfolio. Capital spent on these acquisitions is in addition to the $229 million budgeted for 2007.

*Drilling Activity*

During the nine months ended September 30, 2007, along with our 2006 and 2007 drilling fund partnerships, we drilled a total of 264 gross (220.4 net) wells as detailed below.

| Development Wells Drilled | | | | | |
|---|---|---|---|---|---|
| Three Months Ended September 30, 2007 | | | Nine Months Ended September 30, 2007 | | |
| Productive | Dry | Total | Productive | Dry | Total |

| | | In Process | | | | In Process | | |
|---|---|---|---|---|---|---|---|---|
| **Gross** | | | | | | | | |
| Appalachian | 2 | 2 | - | 4 | 2 | 2 | - | 4 |
| Michigan | - | - | - | - | 2 | - | - | 2 |
| Wattenberg | 10 | 31 | - | 41 | 65 | 40 | 1 | 106 |
| Piceance | 3 | 8 | - | 11 | 27 | 14 | - | 41 |
| NECO | 2 | 35 | 1 | 38 | 51 | 47 | 7 | 105 |
| | 17 | 76 | 1 | 94 | 147 | 103 | 8 | 258 |
| | | | | | | | | |
| **Net** | | | | | | | | |
| Appalachian | 2.0 | 2.0 | - | 4.0 | 2.0 | 2.0 | - | 4.0 |
| Michigan | - | - | - | - | 1.8 | - | - | 1.8 |
| Wattenberg | 8.9 | 20.5 | - | 29.4 | 48.0 | 30.0 | 0.4 | 78.4 |
| Piceance | 3.0 | 5.5 | - | 8.5 | 25.1 | 11.5 | - | 36.6 |
| NECO | 2.0 | 34.9 | 1.0 | 37.9 | 43.0 | 46.9 | 7.0 | 96.9 |
| | 15.9 | 62.9 | 1.0 | 79.8 | 119.9 | 90.4 | 7.4 | 217.7 |

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| | Exploratory Wells Drilled | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Three Months Ended September 30, 2007 | | | | Nine Months Ended September 30, 2007 | | | |
| | Productive | In Process | Dry | Total | Productive | In Process | Dry | Total |
| **Gross** | | | | | | | | |
| Wattenberg | - | - | - | - | - | - | 3 | 3 |
| NECO | - | - | 1 | 1 | - | - | 1 | 1 |
| North Dakota | - | - | - | - | 1 | - | 1 | 2 |
| | - | - | 1 | 1 | 1 | - | 5 | 6 |
| **Net** | | | | | | | | |
| Wattenberg | - | - | - | - | - | - | 1.1 | 1.1 |
| NECO | - | - | 1.0 | 1.0 | - | - | 1.0 | 1.0 |
| North Dakota | - | - | - | - | 0.2 | - | 0.4 | 0.6 |
| | - | - | 1.0 | 1.0 | 0.2 | - | 2.5 | 2.7 |

In addition to the drilling of new wells, we recompleted 44 and 100 wells in the Wattenberg Field area during the three and nine months ended September 30, 2007, respectively.

In 2006, we drilled a total of 222 development wells, of which 216 wells were designated successful. As of December 31, 2006, 82 of the 216 successful wells were awaiting natural gas pipeline connection. As of September 30, 2007, all of the wells awaiting pipeline connection at December 31, 2006, were connected and turned on line. During the nine months ended September 30, 2007, we drilled a total of 258 developmental wells, of which 250 wells were designated as successful. As of September 30, 2007, 103 of the 250 successful wells were awaiting natural gas pipeline connection.

*Garden Gulch Road – Piceance Basin*

During the second quarter of 2007, we, along with several other Piceance Basin operators, completed construction and placed into service an access road from the valley floor to the top of the Mesa (“Garden-Gulch Road”). Our share of the initial cost of the road was $5.1 million. The Garden Gulch Road is adjacent to our compressor facilities in the valley and will provide improved access to approximately 375 drill sites on top of the Mesa. The improved access to the top of the Mesa should result in drilling, completion and production cost savings. Additionally, the road should enable us to conduct drilling operations during the winter on the Mesa, which in prior years was not possible.

*Oil and Gas Properties*

The following table identifies the costs we incurred in oil and gas property acquisition, exploration and development for the nine months ended September 30, 2007.

| | Amount *(in thousands)* |
|---|---|
| Acquisition of properties: | |
| Unproved properties | $ 26,146 |
| Proved properties | 197,426 |
| Development costs | 154,671 |
| Exploration costs | 12,558 |

| | | |
|---|---|---|
| Total costs incurred | $ | 390,801 |

At September 30, 2007, we had an interest in approximately 3,500 wells (1,400 wells in the Appalachian Basin, 200 wells in the Michigan Basin and 1,900 wells in the Rocky Mountain Region). Our ownership interests in these wells range from 1% to 100% and, on average, we have an approximate 64.2% interest in the wells we operate.

At September 30, 2007, we had leases or other development rights to 16,575 undeveloped acres in the northern Appalachian Basin, 120 undeveloped acres in the Michigan Basin, 8,850 undeveloped acres in the Fort Worth Basin and 210,675 undeveloped acres in the Rocky Mountain Region.

*Common Stock Buyback Program*

On October 16, 2006, our Board of Directors approved a stock 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 may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. We may terminate or limit the stock purchase program at any time. Since the inception of the program and for the nine months ended September 30, 2007, we purchased 6,833 shares at a cost of $0.3 million ($50.63 average price per share).

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*Working Capital*

Our working capital usage for the nine months ended September 30, 2007, was $57.5 million. At September 30, 2007, we had available borrowing capacity under our credit facility of $28 million. On October 16, 2007, we increased our borrowing capacity under our credit facility by $75 million to a total of $275 million. We have historically satisfied our working capital needs through free cash flow and borrowings under our credit facility. We may need to raise additional capital in the bank, private and public markets to fund future acquisitions and increases in capital expenditure levels. We expect to continue to maintain adequate liquidity to meet our obligations on an ongoing basis. If we are unable to raise incremental capital, future capital expenditures and acquisitions may be impacted. The outstanding balance under our $275 million credit facility at November 1, 2007, was approximately $260 million. Our plan is to significantly increase capacity under our credit facility. However, it is our view that we can operate with reduced borrowing capacity in the short-term due to near-term cash flow projections, the discretionary nature of our capital program and the demonstrated ability to raise capital in bank, private and public markets.

*Long-Term Debt*

We have a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas with a maximum commitment of $200 million, dated as of November 4, 2005, subject to and secured by required levels of natural gas and oil and reserves. We are required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at 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 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. 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.

Effective August 9, 2007, we entered into the first amendment to our credit facility adding a new bank, Wachovia Bank, N.A, and increasing our aggregate commitments from $150 million to $200 million, all of which is fully activated. The amendment also waived our working capital covenant until the earlier of (i) a debt or equity transaction resulting in net proceeds to us of at least $200 million or (ii) July 1, 2008. Under the amended agreement the ABR rate was increased by 0.375% as long as the waiver of the working capital covenant is in effect.

As of October 16, 2007, we entered into a second amendment to our credit facility with JPMorgan, BNP Paribas and Wachovia Bank, N.A. The amendment (1) increases the aggregate commitments from $200 million to $275 million and allows, with further bank commitment, for a maximum possible credit facility of $400 million; (2) includes three additional lenders: Bank of Oklahoma, Morgan Stanley Bank and Guaranty Bank, FSB (collectively with JP Morgan, BNP Paribas and Wachovia Bank, N.A., (“the banks”)); (3) modifies the waiver of our non-compliance with the working capital covenant received pursuant to the first amendment to extend it to October 1, 2008; and (4) modifies the security to require an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties.

As of November 6, 2007, the Company and the banks, through execution of assignment and assumption agreements and related promissory note agreements, added two additional banks, Royal Bank of Canada and The Royal Bank of Scotland, plc to the credit facility.

As of September 30, 2007, the outstanding balance under the credit facility was $172 million compared to $117 million, excluding the overline note discussed below, as of December 31, 2006. Any amounts outstanding under the credit facility are secured by substantially all of our properties. The outstanding balance at September 30, 2007, was subject to an adjusted LIBOR of 7.5625%. We were in compliance with all covenants as of September 30, 2007.

*Purchase of Natural Gas Wells*

On October 30, 2007, with an effective date of October 1, 2007, we purchased from an unrelated party a majority working interest in 762 natural gas wells located in southwestern Pennsylvania for approximately $53 million. The acquisition includes approximately 47 Bcfe net proved reserves and associated pipelines, equipment, real estate and undeveloped acreage.

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*Contractual Obligations and Contingent Commitments*

The following table represents our contractual obligations as of September 30, 2007.

| Contractual Obligations and Contingent Commitments | Total | Payments due by period Less than 1 year | 1-3 years | 3-5 years | More than 5 years |
|---|---|---|---|---|---|
| | | | *(in thousands)* | | |
| Debt [1] | $ 172,000 | $ - | $ - | $ 172,000 | $ - |
| 2007 partnership funding | 18,712 | 18,712 | - | - | - |
| Operating leases | 4,544 | 1,922 | 1,992 | 630 | - |
| Asset retirement obligations | 18,198 | 50 | 200 | 200 | 17,748 |
| Drilling rig commitments [2] | 26,412 | 7,014 | 19,398 | - | - |
| Pipeline expansion agreement [3] | 1,197 | - | 1,197 | - | - |
| Derivative agreements [4] | 3,354 | 2,773 | 581 | - | - |
| Other liabilities [5] | 10,685 | 377 | 4,172 | 720 | 5,416 |
| Total | $ 255,102 | $ 30,848 | $ 27,540 | $ 173,550 | $ 23,164 |

(1) *Long-term debt in the above table does not include interest because interest rates are variable and principal balances fluctuate significantly from period to period. We continue to pursue capital investment opportunities in producing natural gas properties as well as our plan to participate in our sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and cost efficiencies. Our Management believes we have adequate capital to meet our operating requirements.*

(2) *Drilling rig commitments in the above table do 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.*

(3) *Amount represents maximum obligation pursuant to our agreement to invest $65 million, for our own benefit, to develop specified acreage in the Wattenberg Field area during a three-year period ending December 31, 2009.*

(4) *Amount represents gross liability related to fair value of derivatives. Includes fair value of derivatives for Riley Natural Gas, Petroleum Development Corporation's share of oil and natural gas production and derivatives contracts we entered into on behalf of the affiliate partnerships as the managing general partner. We have a related net payable to the partnerships of $2.3 million as of September 30, 2007.*

(5) *Includes unrecognized tax benefits recorded pursuant to FIN No. 48 and other long-term obligations.*

*Commitments and Contingencies*

As managing general partner of 33 partnerships, we are liable for any potential casualty losses in excess of the partnership assets and insurance. Our management believes that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

**Recent Accounting Pronouncements**

See Note 2, *Recent Accounting Standards*, to the Condensed Consolidated Financial Statements.

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

Interest Rate Risk

Our exposure to market risk for changes in interest rates relates primarily to our interest-bearing cash and cash equivalents and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, short-term certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of September 30, 2007, is $44.8 million with an average interest rate of 4.2%. As of September 30, 2007, we had long-term debt of $172 million subject to LIBOR of 7.5625%. Based on the September 30, 2007, credit facility borrowings, a 1% change in interest rates would have an annual $1.1 million after tax impact on our financial statements.

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Commodity Price Risk

We utilize commodity based derivative instruments to manage a portion of our exposure to price risk from our oil and natural gas sales and marketing activities. Our policy prohibits the use of oil and natural gas future and option contracts for speculative purposes. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for NECO production and CIG-based contracts for other Colorado production. We purchase puts and participating collars for our own and affiliate partnerships production to protect against possible price instability 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. As a result, 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.

The net fair value of the commodity based derivatives was $14.5 million and $13.6 million at September 30, 2007, and December 31, 2006, respectively. We recognized in the statement of income an unrealized gain on commodity based derivatives of $1.3 million for the nine months ended September 30, 2007, and an unrealized gain of $7.6 million for the nine months ended September 30, 2006.

A 10% increase in natural gas prices above the September 30, 2007, prices would have resulted in a decrease in unrealized gains of $2.7 million and a 10% decrease in natural gas prices would have resulted in a increase in unrealized gains of $3 million as of September 30, 2007.

See Note 17, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements, for a summary of the open derivative option and purchase and sales contracts for us and RNG as of September 30, 2007.

In addition to including the gross assets and liabilities related to our share of oil and natural gas production, the summary of open derivative positions include the gross assets and liabilities related to derivative contracts we entered into on behalf of the affiliate partnerships as the managing general partner. The accompanying consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of $5.8 million as of September 30, 2007, and $7.5 million as of December 31, 2006.

The following table presents average CIG and NYMEX closing prices for our natural gas and oil production for the nine months ended September 30, 2007, and year ended December 31, 2006, as well as the range of high and low prices for the respective commodity. Future near-term natural gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

| | Nine Months Ended September 30, 2007 | Year Ended December 31, 2006 |
|---|---|---|
| **Natural Gas (per Mmbtu)** | | |
| CIG | $ 4.10 | $ 5.63 |
| NYMEX | 6.83 | 7.23 |
| High | 18.56 | 15.70 |
| Low | 1.68 | 2.26 |

| | | |
|---|---|---|
| **Oil (per Barrel)** | | |
| NYMEX | 63.50 | 64.73 |
| High | 66.49 | 71.77 |
| Low | 40.60 | 53.75 |

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**Item 4. Controls and Procedures**

**Material Weaknesses Previously Disclosed**

As discussed in our 2006 Form 10-K, we did not maintain effective controls as of December 31, 2006, over the (1) timely reconciliation, review and adjustment of significant balance sheet and income statement accounts, (2) proper identification of all derivative contracts related to oil and gas sales to ensure the fair value determination of certain derivatives, and (3) proper accounting for oil and gas properties for capitalization of costs and the accurate calculation of depreciation and depletion.

**Evaluation of Disclosure Controls and Procedures**

As of September 30, 2007, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in Securities Exchange Act of 1934, Rule 13a-15(e) and 15d-15(e)). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, the CEO and the CFO concluded that as a result of the material weaknesses cited above, our disclosure controls and procedures were not effective as of September 30, 2007. Because of these material weaknesses, we performed additional procedures to ensure that our financial statements as of and for the three and nine months ended September 30, 2007, were fairly presented in all material respects in accordance with generally accepted accounting principles.

**Changes in Internal Control Over Financial Reporting**

During the third quarter of 2007, we made the following changes in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect our internal controls over financial reporting:

- Installed new software for our accounts payable process as part of a broader financial reporting system implementation. The new system enhanced the existing internal control framework over accounts payable and cash distribution process by automating several of the previously manual controls.

Additionally, during the first quarter of 2007, and continuing through the filing of this Form 10-Q, we implemented the following changes in internal control over financial reporting:

- Reinforced reconciliation procedures to ensure the timely reconciliation, review and adjustments to significant balance sheet and income statement accounts;

- Developed and approved extensive policies and procedures concerning the controls over financial reporting for derivatives;

- Provided additional training regarding derivatives for key personnel;

-

Developed a review process to ensure proper accounting for oil and gas properties, specifically the capitalization of costs and calculation of depreciation and depletion.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

## PART II - OTHER INFORMATION

### Item 1. Legal Proceedings

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

*Royalty Payments*. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against us in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells we operated in the State of Colorado. The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for the alleged underpayment of royalties we made to the plaintiff pursuant to leases. We moved the case to Federal Court on June 28, 2007, and on July 10, 2007, we filed our answer and affirmative defenses. A scheduling order has not been issued at this time and no discovery has taken place. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, we are unable to predict the ultimate outcome of this suit at this time.

**Item 1A. Risk Factors**

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of common stock are described in item 1A, *"Risk Factors",* of our 2006 Form 10-K , as filed with the SEC on May 23, 2007. This information should be considered carefully, together with other information in this report and other reports and materials that we file, or has filed, with the SEC. There have been no material changes from the risk factors previously disclosed in our 2006 Form 10-K, 2007, except for the following:

***Information technology financial systems implementation issues could disrupt our internal business operations and adversely affect our business financial results or our ability to report our financial results.***

We are currently in the process of implementing a new financial software system to enhance operating efficiencies and provide more effective management of our business operations. Our implementation is based on a phased approach, with the financial reporting system to be implemented in the first quarter of 2008. Implementations of financial system and related software carry such risks as cost overruns, project delays, business interruptions and delays. If we experience a business interruption as a result of our financial system implementation, it could have an adverse effect on our business, increase our expense, affect our ability to report in an accurate and timely manner of our financial position, results of operations and cash flows and to otherwise operate our business.

***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 in a single major geographic area.***

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

During the second half of 2007, natural gas prices in the Rocky Mountain region have fallen disproportionately when compared to other markets, due in part to continuing constraints in transporting natural gas from producing properties in the region. Because of the concentration of our operations in the Rocky Mountain region, such price decreases are more likely to have a material adverse effect on our revenue, profitability and cash flow than those of our more geographically diverse competitors.

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**Item 2. Unregistered Sales of Equity Securities and Use of Proceeds**

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

ISSUER PURCHASES OF EQUITY SECURITIES

| Period | Total number of shares purchased | Average price paid per share | Total number of shares purchased as part of publicly announced plans or programs | Maximum number of shares that may yet be purchased under the plans or programs |
|---|---|---|---|---|
| September 1-30, 2007 | 79 | $ 39.14 | 79 | 1,470,276 |
| | 79 | 39.14 | 79 | 1,470,276 |

On October 16, 2006, our Board of Directors approved a stock 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 may be made in the open market or in private transactions, at times and in amounts that management deems appropriate. We may terminate or limit the stock purchase program at any time. Since the inception of this October 2006 program, we purchased 6,833 shares at a cost of $0.3 million ($50.63 average price per share).

**Item 3. Defaults Upon Senior Securities – None.**

**Item 4. Submission of Matters to a Vote of Security Holders**

The following provides a summary of votes cast for the proposals on which our shareholders voted at our annual meeting of shareholders held on August 28, 2007, in Bridgeport, West Virginia.

Proposal No. 1 – Election of two directors to serve three-year terms expiring in 2010.

| Nominee | For | Withheld |
|---|---|---|
| Vincent F. D'Annunzio | 13,337,356 | 450,069 |
| Thomas E. Riley | 13,342,974 | 444,451 |

The following director terms continued after the annual meeting of shareholders.

| Director | Term Expiring |
|---|---|
| David C. Parke | 2008 |
| Jeffrey C. Swoveland | 2008 |
| Kimberly Luff Wakim | 2009 |
| Steven R. Williams | 2009 |
| Anthony J. Crisafio | 2009 |

Proposal No. 2 – Ratification of selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2007.

| For | Against | Abstain |
|---|---|---|
| 13,680,939 | 90,172 | 17,251 |

**Item 5. Other information – None.**

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**Item 6. Exhibits**

| **Exhibit No.** | **Description** |
|---|---|
| 3.1 | Amended and Restated Certificate of Incorporation of Petroleum Development Corporation, incorporated by reference to Exhibit 3.1 to Form S-2, SEC File No. 333-36369, filed on September 25, 1997. |
| 3.2 | Bylaws of Petroleum Development Corporation, amended and restated effective October 11, 2007, incorporated by reference to Exhibit 3.2 to Form 8-K filed on October 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, incorporated by reference to Exhibit 4.1 to Form 8-K filed September 14, 2007. |
| 10.1 | 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., incorporated by reference to Exhibit 10.1 to Form 8-K filed August 15, 2007. |
| 10.2 | 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, incorporated by reference to Exhibit 10.1 to Form 8-K filed October 22, 2007. |
| 10.3 | Indemnification Agreement with Directors and Officers, incorporated by reference to Exhibit 10.1 to Form 10-Q filed August 9, 2007. |
| 10.4 | 2007 Long-Term Incentive Program, incorporated by reference to Exhibit 10.1 to Form 8-K filed on April 13, 2007. |
| 10.5 | Form of Stock Option and Restricted Stock Agreement, incorporated by reference to Exhibit 10.1 to Form 8-K filed on April 10, 2007. |
| 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. |
| 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. |
| 32 | 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. |

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**SIGNATURES**

Pursuant to the requirements 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
(Registrant)

Date: November 9, 2007

/s/ Steven R. Williams
Steven R. Williams
Chief Executive Officer
(Duly authorized officer and principal executive officer)

Date: November 9, 2007

/s/ Richard W. McCullough
Richard W. McCullough
Chief Financial Officer
(Principal financial officer)