PANHANDLE OIL & GAS INC
Form 10-Q
August 10, 2009

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**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
**FORM 10-Q**

þ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
**For the period ended June 30, 2009**

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
**For the transition period from __________ to __________**

**Commission File Number 001-31759**
**PANHANDLE OIL AND GAS INC.**
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| OKLAHOMA | 73-1055775 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

Grand Centre Suite 300, 5400 N Grand Blvd., Oklahoma City, Oklahoma 73112

(Address of principal executive offices)

Registrant s telephone number including area code (405) 948-1560

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.
þ Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

| | | | |
|---|---|---|---|
| Large accelerated filer o | Accelerated filer þ | Non-accelerated filer o<br>(Do not check if a smaller reporting company) | Smaller Reporting Company o |

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

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

Outstanding shares of Class A Common stock (voting) at August 7, 2009: 8,300,128

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**PART 1 FINANCIAL INFORMATION**
PANHANDLE OIL AND GAS INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Information at June 30, 2009 is unaudited)

| | June 30, 2009 | September 30, 2008 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 605,090 | $ 895,708 |
| Oil and natural gas sales receivables (net) | 7,548,471 | 17,183,128 |
| Short-term derivative contracts | | 646,193 |
| Refundable income taxes | | 2,162,305 |
| Assets held for sale | 893,325 | |
| Other | 708,143 | 217,691 |
| Total current assets | 9,755,029 | 21,105,025 |
| Properties and equipment, at cost, based on successful efforts accounting: | | |
| Producing oil and natural gas properties | 195,946,566 | 175,727,196 |
| Non-producing oil and natural gas properties | 10,254,992 | 11,216,103 |
| Other | 546,676 | 491,321 |
| | 206,748,234 | 187,434,620 |
| Less accumulated depreciation, depletion and amortization | 106,949,000 | 87,661,433 |
| Net properties and equipment | 99,799,234 | 99,773,187 |
| Investments | 681,021 | 736,314 |
| Other | 515,247 | 392,657 |
| Total assets | $ 110,750,531 | $ 122,007,183 |
| **Liabilities and Stockholders Equity** | | |
| Current liabilities: | | |
| Accounts payable | $ 4,586,336 | $ 15,897,565 |
| Short-term derivative contracts | 29,389 | |
| Prepayment of sales price on assets to be sold | 2,514,343 | |
| Accrued liabilities | 814,277 | 608,456 |
| Total current liabilities | 7,944,345 | 16,506,021 |
| Long-term debt | 13,332,504 | 9,704,100 |
| Deferred income taxes | 22,818,750 | 25,943,750 |
| Asset retirement obligations | 1,672,978 | 1,504,411 |
| Long-term derivative contracts | 894,240 | |

| | | |
|---|---|---|
| Stockholders equity: | | |
| Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at June 30, 2009 and at September 30, 2008 | 140,524 | 140,524 |
| Capital in excess of par value | 2,090,070 | 2,090,070 |
| Deferred directors compensation | 1,836,048 | 1,605,811 |
| Retained earnings | 64,745,180 | 69,236,604 |
| | 68,811,822 | 73,073,009 |
| Less treasury stock, at cost; 131,374 shares at June 30, 2009 and at September 30, 2008 | (4,724,108) | (4,724,108) |
| Total stockholders equity | 64,087,714 | 68,348,901 |
| Total liabilities and stockholders equity | $ 110,750,531 | $ 122,007,183 |

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

| | Three Months Ended June 30, 2009 | Three Months Ended June 30, 2008 | Nine Months Ended June 30, 2009 | Nine Months Ended June 30, 2008 |
|---|---|---|---|---|
| Revenues: | | | | |
| Oil and natural gas sales | $ 9,058,169 | $ 20,551,865 | $ 28,114,989 | $ 48,687,560 |
| Lease bonuses and rentals | 28,777 | 32,154 | 182,019 | 110,464 |
| Gains (losses) on derivative contracts | (470,974) | (2,286,789) | 212,578 | (4,391,316) |
| Gain on asset sales, interest and other | 114,744 | 105,963 | 211,202 | 190,718 |
| Income of partnerships | 49,244 | 50,013 | 252,889 | 306,805 |
| | 8,779,960 | 18,453,206 | 28,973,677 | 44,904,231 |
| Costs and expenses: | | | | |
| Lease operating expenses | 2,095,933 | 2,178,732 | 5,772,401 | 4,977,151 |
| Production taxes | 369,802 | 675,206 | 1,117,040 | 2,431,165 |
| Exploration costs | 112,537 | 35,394 | 314,845 | 397,125 |
| Depreciation, depletion and amortization | 6,844,813 | 4,671,193 | 20,882,405 | 13,376,346 |
| Provision for impairment | 115,892 | 37,666 | 2,124,133 | 385,672 |
| Loss on sale of assets | | 203,387 | | 203,387 |
| General and administrative | 1,174,315 | 1,164,743 | 3,721,070 | 3,991,566 |
| Interest expense | 68,180 | | 68,180 | 44,346 |
| | 10,781,472 | 8,966,321 | 34,000,074 | 25,806,758 |
| Income (loss) before provision (benefit) for income taxes | (2,001,512) | 9,486,885 | (5,026,397) | 19,097,473 |
| Provision (benefit) for income taxes | (1,073,000) | 3,018,000 | (2,278,000) | 6,317,000 |
| Net income (loss) | $ (928,512) | $ 6,468,885 | $ (2,748,397) | $ 12,780,473 |
| Earnings (loss) per common share (Note 4) | $ (0.11) | $ 0.76 | $ (0.33) | $ 1.50 |
| Weighted average shares outstanding: | | | | |
| Common shares | 8,300,128 | 8,423,067 | 8,300,128 | 8,428,701 |
| Unissued, vested directors shares | 97,867 | 85,909 | 96,325 | 84,911 |
| | 8,397,995 | 8,508,976 | 8,396,453 | 8,513,612 |
| Dividends declared per share of common stock and paid in period | $ 0.07 | $ 0.07 | $ 0.21 | $ 0.21 |

(See accompanying notes)
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PANHANDLE OIL AND GAS INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(Information at and for the nine months ended June 30, 2009 is unaudited)
Nine Months Ended June 30, 2009

| | Class A voting Common Stock Shares | Class A voting Common Stock Amount | Capital in Excess of Par Value | Deferred Directors Compensation | Retained Earnings | Treasury Shares | Treasury Stock | Total |
|---|---|---|---|---|---|---|---|---|
| Balances at September 30, 2008 | 8,431,502 | $ 140,524 | $ 2,090,070 | $ 1,605,811 | $ 69,236,604 | (131,374) | $ (4,724,108) | $ 68,348,901 |
| Net loss | | | | | (2,748,397) | | | (2,748,397) |
| Dividends ($.21 per share) | | | | | (1,743,027) | | | (1,743,027) |
| Increase in deferred directors compensation charged to expense | | | | 230,237 | | | | 230,237 |
| Balances at June 30, 2009 | 8,431,502 | $ 140,524 | $ 2,090,070 | $ 1,836,048 | $ 64,745,180 | (131,374) | $ (4,724,108) | $ 64,087,714 |

(See accompanying notes)
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PANHANDLE OIL AND GAS INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

| | Nine months ended June 30, 2009 | 2008 |
|---|---|---|
| **Operating Activities** | | |
| Net income (loss) | $ (2,748,397) | $ 12,780,473 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| (Gain) loss, net, on sale of assets | (181,760) | 83,986 |
| Income of partnerships | (252,889) | (306,805) |
| Exploration costs | 314,845 | 397,125 |
| Depreciation, depletion and amortization | 20,882,405 | 13,376,346 |
| Provision for impairment | 2,124,223 | 385,672 |
| Deferred income taxes | (3,125,000) | 4,275,000 |
| Distributions received from partnerships | 308,182 | 368,413 |
| Directors deferred compensation expense | 230,237 | 225,965 |
| Cash provided by changes in assets and liabilities: | | |
| Oil and natural gas sales receivables | 9,634,657 | (9,359,047) |
| Derivative contracts | 1,569,822 | 3,613,416 |
| Refundable income taxes | 2,162,305 | |
| Other current assets | (490,452) | (819,020) |
| Other non-current assets | (122,590) | |
| Accounts payable | 106,136 | 130,477 |
| Accrued liabilities | 39,902 | 322,991 |
| Income taxes payable | 165,919 | |
| Total adjustments | 33,365,942 | 12,694,519 |
| Net cash provided by operating activities | 30,617,545 | 25,474,992 |
| **Investing Activities** | | |
| Capital expenditures, including dry hole costs | (35,509,890) | (27,757,275) |
| Proceeds from leasing of fee mineral acreage | 202,007 | 131,449 |
| Proceeds from asset sales | 2,514,343 | 181,120 |
| Net cash used in investing activities | (32,793,540) | (27,444,706) |
| **Financing Activities** | | |
| Borrowings under credit facility | 43,705,195 | 40,058,723 |
| Payments on credit facility | (40,076,791) | (34,701,332) |
| Purchase of treasury stock | | (1,955,761) |
| Payments of dividends | (1,743,027) | (1,770,615) |
| Net cash provided by financing activities | 1,885,377 | 1,631,015 |

| | | |
|---|---|---|
| Decrease in cash and cash equivalents | (290,618) | (338,699) |
| Cash and cash equivalents at beginning of period | 895,708 | 989,360 |
| Cash and cash equivalents at end of period | $ 605,090 | $ 650,661 |
| **Supplemental Schedule of Noncash Investing and Financing Activities** | | |
| Receivable from asset sales | $ | $ 658,668 |
| Additions to asset retirement obligations | $ 168,567 | $ |
| Gross additions to properties and equipment | $ 24,069,809 | $ 29,625,707 |
| Net (increase) decrease in accounts payable for properties and equipment additions | 11,440,081 | (1,868,432) |
| Capital expenditures, including dry hole costs | $ 35,509,890 | $ 27,757,275 |

(See accompanying notes)
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PANHANDLE OIL AND GAS INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1: Accounting Principles and Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of Panhandle Oil and Gas Inc. (the Company) have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission (SEC), and include the Company s wholly-owned subsidiary, Wood Oil Company (Wood). Management of the Company believes that all adjustments necessary for a fair presentation of the consolidated financial position and results of operations for the periods have been included. All such adjustments are of a normal recurring nature. The consolidated results are not necessarily indicative of those to be expected for the full year. The Company s fiscal year runs from October 1 through September 30.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the SEC. Therefore, these condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in the Company s 2008 Annual Report on Form 10-K.

NOTE 2: Income Taxes

The Company s benefit or provision for income taxes (both federal and state) differs from the statutory rate primarily due to estimated state benefit generated in part from estimated excess Oklahoma percentage depletion, estimated excess federal percentage depletion and a valuation allowance in 2009 ($278,000) placed on certain state tax net operating loss carryforwards (NOLs) the Company no longer believes are more likely than not to be utilized in future periods prior to expiration. The estimated state benefit is largely due to excess Oklahoma percentage depletion, not limited to Oklahoma taxable income, which reduces estimated state taxable income or adds to estimated state taxable loss projected for the year. The federal and Oklahoma excess percentage depletion allowance estimates will be updated throughout the year until finalized with the detail well-by-well calculations at fiscal year-end. The effect of the federal and Oklahoma excess percentage depletion when a benefit for income taxes is recorded, is to increase the effective tax rate (as is the case as of June 30, 2009), while the effect is to decrease the effective tax rate when a provision for income taxes is recorded. The benefit of federal and Oklahoma excess percentage depletion and the provision related to the state NOL valuation allowances are not directly related to the amount of loss or income recorded in a period. Accordingly, in periods where a recorded loss or income is relatively small, the proportional effect of these items on the effective tax rate may be significant.

On October 1, 2007, the Company adopted the provisions of FIN No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* (SFAS 109). FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company and its subsidiary file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for years prior to fiscal year 2006.

NOTE 3: Stock Repurchase Program

On May 28, 2008 and July 29, 2008, the Company announced that its Board of Directors had approved stock repurchase programs to purchase up to $2,000,000 and $3,000,000, respectively, of the Company s common stock. The shares are held in treasury and are accounted for using the cost method. Total shares purchased under the two programs were 139,014. On September 30, 2008, 7,640 treasury shares were contributed to the Company s ESOP on behalf of the ESOP participants, leaving 131,374 shares held in treasury as of June 30, 2009.

NOTE 4: Earnings (Loss) per Share

Earnings (loss) per share is calculated using net income (loss) divided by the weighted average number of voting common shares outstanding, including unissued, vested directors shares during the period.

NOTE 5: Long-term Debt

Effective February 3, 2009, the Company amended its revolving credit facility with Bank of Oklahoma (BOK) to increase the borrowing base from $15,000,000 to $25,000,000 (the revolving loan amount remains $50,000,000), restructure the interest rate, secure the loan by certain of the Company s properties and change the maturity date to October 31, 2011. Effective May 20, 2009 the Company again increased the borrowing base from $25,000,000 to $35,000,000. The restructured interest rate is based on national prime plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. The 4.50% interest rate floor has been in effect since the amendment. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company s oil and natural gas properties is advanced. If the interest rate calculation utilizing the national prime or LIBOR rate exceeds the interest rate floor, the interest rate spread from national prime or LIBOR will be charged based on the percent of the value advanced of the calculated loan value of the Company s oil and natural gas properties.

NOTE 6: Dividends

On May 20, 2009, the Company s Board of Directors approved payment of a $.07 per share dividend that was paid on June 12, 2009 to shareholders of record on June 1, 2009.

NOTE 7: Deferred Compensation Plan for Directors

The Company has a deferred compensation plan for non-employee directors (Plan). The Plan provides that each eligible director can individually elect to receive shares of Company stock rather than cash for board and committee chair retainers, board meeting fees and board committee meeting fees. These shares are unissued and immediately vested. The shares are credited to each director s deferred fee account at the closing market price of the stock on the date earned. Upon retirement, termination or death of the director or upon a change in control of the Company, the shares accrued under the Plan will be issued to the director.

NOTE 8: Oil and Natural Gas Reserves

The estimation of crude oil and natural gas reserves affects depreciation, depletion and amortization (DD&A) and impairment calculations. On an annual basis, with a semi-annual update, the Company s consulting engineer (Pinnacle Energy Services, LLC), with assistance from Company staff, prepares estimates of crude oil and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. Separate reserve estimates are made using current and projected future prices of crude oil and natural gas. According to guidelines and definitions established by the SEC, DD&A must be calculated using non-escalated prices current with the period end for which estimates are being made, while reserve estimations used in assessments for asset impairments are calculated using projected future crude oil and natural gas prices. When significant crude oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing price decks current with the period. For DD&A calculation purposes, crude oil and natural gas reserves as of June 30, 2009 were updated, utilizing June 30, 2009 crude oil and natural gas prices ($66.77 per barrel of crude oil and $2.98 per mcf of natural gas) held flat over the lives of the properties. The update of crude oil and natural gas reserves utilizing price decks as of June 30, 2009 positively impacted the reserves as the higher prices extended the economic lives of the Company s properties resulting in higher overall reserve volumes. The higher prices resulted in upward revisions to crude oil and natural gas reserves of approximately 74,000 barrels and 4,016,000 mcf, respectively. In comparison, prices used for the March 31, 2009 semi-annual update were $46.93 per barrel of crude oil and $2.47 per mcf of natural gas held flat over the lives of the properties. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

NOTE 9: Impairment

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil and natural gas, future production costs, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and natural gas reserves. When significant crude oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing updated projected future price decks current with the period. To assess assets for impairment as of June 30, 2009, projected future crude oil prices (from $67.25 per barrel to $83.96 per barrel) and natural gas prices (from $3.23 per mcf to $7.43 per mcf) were used to estimate crude oil and natural gas reserves. The assessment resulted in an impairment provision of $115,892 for the June 30, 2009 quarter. A future reduction in oil and natural gas prices or a

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decline in reserve volumes would likely lead to additional impairment in future periods that may be material to the Company.

NOTE 10: Capitalized Costs

Oil and natural gas properties include costs of $9,851 on exploratory wells which were drilling or testing at June 30, 2009. The Company is expecting to have evaluation results on these wells within the next six months.

NOTE 11: Derivatives

The Company accounts for its derivative contracts under Financial Accounting Standards Board Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, (SFAS No. 133). Under the provision of SFAS No. 133, the Company is required to recognize all derivative instruments as either assets or liabilities in the consolidated balance sheet at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Hedge effectiveness is required to be measured at least quarterly based on relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. The ineffective portion of a derivative s change in fair value is recognized in current earnings. For derivative instruments not designated as hedging instruments, the change in fair value is recognized in earnings during the period of change as a change in derivative fair value. At June 30, 2009, the Company had no derivative contracts designated as cash flow hedges.

Historically, the Company entered into costless collar arrangements (all of which expired in the fiscal 2009 first quarter), but currently has entered into fixed swap contracts, both of which were intended to reduce the Company s exposure to short-term fluctuations in the price of natural gas. Collar contracts set a fixed floor price and a fixed ceiling price and provide for payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide for payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. These arrangements cover only a portion of the Company s natural gas production and provide only partial price protection against declines in natural gas prices. These economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices. The derivative instruments will settle based on the prices below which are tied to two pipelines in Oklahoma.

Derivative contracts in place as of June 30, 2009
(prices below reflect the Company s net price from the listed Oklahoma pipelines)

| Contract period | Production volume covered per month | Indexed (1) Pipeline | Fixed price |
|---|---|---|---|
| March December, 2009 | 60,000 mmbtu | CEGT | $ 4.01 |
| April December, 2009 | 100,000 mmbtu | CEGT | $ 3.71 |
| May December, 2009 | 70,000 mmbtu | CEGT | $3.615 |
| July December, 2009 | 70,000 mmbtu | PEPL | $3.745 |
| January December, 2010 | 100,000 mmbtu | CEGT | $5.015 |
| | 50,000 mmbtu | CEGT | $5.050 |

| | | | |
|---|---|---|---|
| January December, 2010 | | | |
| January December, 2010 | 100,000 mmbtu | PEPL | $ 5.57 |
| January December, 2010 | 50,000 mmbtu | PEPL | $ 5.56 |

(1) CEGT Centerpoint Energy Gas Transmission s East pipeline in Oklahoma

PEPL Panhandle Eastern Pipeline Company s Texas/Oklahoma mainline

While the Company believes that its derivative contracts are effective in achieving the risk management objective for which they were intended, the Company has elected not to complete all of the documentation requirements necessary under SFAS No. 133 to permit these derivative contracts to be accounted for as cash flow hedges. The Company s net fair value of

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derivative contracts was a liability of $923,629 as of June 30, 2009 and an asset of $646,193 as of September 30, 2008. Realized and unrealized gains (losses) for the periods ended June 30, 2009 and June 30, 2008 are scheduled below:

| Gains (losses) on natural gas derivative contracts - current | Three months ended 6/30/2009 | Three months ended 6/30/2008 | Nine months ended 6/30/2009 | Nine months ended 6/30/2008 |
|---|---|---|---|---|
| Realized | $ 660,400 | $ (878,900) | $ 1,782,400 | $ (777,900) |
| Increase (decrease) in fair value | (519,674) | (1,407,889) | (675,582) | (3,613,416) |
| Total | $ 140,726 | $ (2,286,789) | $ 1,106,818 | $ (4,391,316) |

| Gains (losses) on natural gas derivative contracts - long-term | Three months ended 6/30/2009 | Three months ended 6/30/2008 | Nine months ended 6/30/2009 | Nine months ended 6/30/2008 |
|---|---|---|---|---|
| Realized | $ | $ | $ | $ |
| Decrease in fair value | (611,700) | | (894,240) | |
| Total | $ (611,700) | $ | $ (894,240) | $ |

In accordance with FASB Interpretation No. 39, to the extent that a legal offset exists, the Company nets the fair value of its derivative contracts with the same counterparty in the accompanying balance sheets. The following table summarizes the Company s derivative contracts as of June 30, 2009 and September 30, 2008:

| | Balance Sheet Location | 6/30/2009 Fair Value | 9/30/2008 Fair Value |
|---|---|---|---|
| **Asset Derivatives:** | | | |
| Derivatives not designated as Hedging Instruments under Statement 133 (a): | | | |
| Commodity contracts | Short-term derivative contracts | $ 371,621 | $ 654,195 |
| Commodity contracts | Long-term derivative contracts | | |
| Total Asset Derivatives (b) | | $ 371,621 | $ 654,195 |
| **Liability Derivatives:** | | | |
| Derivatives not designated as Hedging Instruments under Statement 133 (a): | | | |
| Commodity contracts | Short-term derivative contracts | $ 401,010 | $ 8,002 |
| Commodity contracts | Long-term derivative contracts | 894,240 | |
| Total Liability Derivatives (b) | | $ 1,295,250 | $ 8,002 |

(a) There were no derivatives designated as Hedging Instruments under Statement 133 for any of the periods presented.

(b) See Note 13 for further disclosures regarding fair value of financial instruments.

The fair value of derivative assets and derivative liabilities is adjusted for credit risk only if the impact is deemed material. The impact of credit risk was immaterial for all periods presented.

NOTE 12: Exploration Costs

Certain non-producing leases which have expired or which have no future plans of development with an aggregate carrying value of $89,839 were fully impaired and charged to exploration costs in the quarter ended June 30, 2009, along with $22,698 related to exploratory dry holes. In the quarter ended June 30, 2008, $35,399 was charged to exploration costs for non-producing leases which had expired or which had no future plans of development, slightly offset by small credits on previously recorded exploratory dry holes.

NOTE 13: Fair Value Measurements

Effective October 1, 2008, the Company adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements for its financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities. The Company has only partially applied SFAS No. 157 and will delay full application for nonfinancial assets and liabilities until the Company s fiscal year beginning October 1, 2009 as permitted by FSP 157-2. The Company is currently assessing the impact that full application for nonfinancial assets and liabilities will have on its financial position, results of operations and cash flows.

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SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2009.

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total Fair Value |
|---|---|---|---|---|
| Financial Assets (Liabilities): | | | | |
| Derivative Contracts Swaps | $ | $(923,629) | $ | $(923,629) |

Level 2 Fair Value Measurements

*Derivatives.* The fair values of the Company s natural gas swaps are corroborated by observable market data by correlation to Nymex pricing. These values are based upon, among other things, future prices and time to maturity.

Level 3 Fair Value Measurements

*Derivatives*. The fair values of the Company s derivatives, excluding natural gas swaps, are based on estimates provided by its respective counterparty and reviewed internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility and time to maturity.

A reconciliation of the Company s assets classified as Level 3 measurements is presented below.

| | Derivatives |
|---|---|
| Balance of Level 3 as of October 1, 2008 | $ 646,193 |
| Total gains or losses (realized/unrealized): | |
| Included in earnings | 393,007 |
| Included in other comprehensive income (loss) | |
| Purchases, issuances and settlements | (1,039,200) |
| Transfers in and out of Level 3 | |
| Balance of Level 3 as of June 30, 2009 | $ |

NOTE 14: Fair Values of Financial Instruments

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, derivative contracts, refundable income taxes, accounts payable and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair value of Company s debt approximates its carrying amount due to the interest rates on the Company s revolving line of credit being rates which are approximately equivalent to market rates for similar type debt based on the Company s credit worthiness.

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NOTE 15: Subsequent Events

As new horizontal drilling development had begun in the Southeast Leedey field in Dewey County, Oklahoma the Company decided to evaluate its oil and natural gas properties in the field. Upon completion of this evaluation, the Company decided to retain all of its mineral interests and 33% of its leasehold interests in the field for future horizontal drilling development, but to explore the potential of monetizing the remaining 67% of its leasehold ownership which contains several mature vertically drilled wells determined to be economically marginal. After negotiations with two potential buyers, the Company entered into an agreement on June 26, 2009 to sell 67% of its leasehold interests in the Southeast Leedey field effective July 1, 2009. On June 26, 2009 the Company received $2,514,343 as a full prepayment of the sales price for the properties. This amount is reported under the current liabilities section of the June 30, 2009 Balance Sheet as prepayment of sales price on assets to be sold pending the transfer of ownership in the properties on July 1, 2009. The Company transferred ownership on July 1, and will record the sale of the properties with associated gain on sale of assets in the fourth quarter. The basis of the properties sold was approximately $890,000 and is reflected as current assets held for sale at June 30, 2009.

Subsequent events have been evaluated through August 10, 2009. This was the same date that the financial statements were filed with the SEC.

NOTE 16: New Accounting Pronouncements

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. Since the Company has not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on its financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. This statement was adopted effective January 1, 2009 and will not have a material impact on the Company s financial disclosures.

In December 2008, the SEC released Final Rule, *Modernization of Oil and Gas Reporting*. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The new disclosure requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of this rule will have on its financial disclosures.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, which require that disclosures concerning the fair value of financial instruments be presented in interim as well as annual financial statements. FSP FAS 107-1 and APB 28-1 are prospectively effective for interim reporting periods ending after June 15, 2009. Effective June 30, 2009 the Company has adopted FSP FAS 107-1 and APB 28-1. The adoption of FSP FAS 107-1 and APB 28-1 required additional disclosures regarding the Company s financial instruments; however, it did not impact the Company s results of operations or financial condition.

In May 2009, the FASB issued Statement 165, which sets forth the following: 1) The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements 2) The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements 3) The disclosures that an entity should make about events or transactions that occurred after the balance sheet date. This statement is effective for interim and annual financial periods ending after June 15, 2009. Effective June 30, 2009 the Company has adopted Statement 165. This Statement did not result in significant changes in the subsequent events that the Company reports, either through recognition or disclosure, in its financial statements.

Other accounting standards that have been issued or proposed by the FASB or other standards-setting bodies that do not require adoption until a future date are not expected to have a material impact on the consolidated financial statements upon adoption.

## ITEM 2 MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Forward-Looking Statements for fiscal 2009 and later periods are made in this document. Such statements represent estimates by management based on the Company s historical operating trends, its proved oil and natural gas reserves and other information currently available to management. The Company cautions that the Forward-Looking Statements provided herein are subject to all the risks and uncertainties incident to the acquisition, development and marketing of, and exploration for oil and natural gas reserves. Investors should also read the other information in this Form 10-Q and the Company s 2008 Annual Report on Form 10-K where risk factors are presented and further discussed. For all the above reasons, actual results may vary materially from the Forward-Looking Statements and there is no assurance that the assumptions used are necessarily the most likely to occur.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2009, the Company had positive working capital of $1,810,684, as compared to positive working capital of $4,599,004 at September 30, 2008. The decrease in working capital resulted from a large decrease in oil and natural gas sales receivables, a decrease in refundable income taxes and increases in prepayment of sales price on assets to be sold, partially offset by a sizable decrease in accounts payable. Significantly lower oil and natural gas sales prices received during fiscal 2009 have greatly reduced the Company s receivables from the sale of oil and natural gas. The lower fiscal 2009 oil and natural gas sales prices have also been the main factor in decreased drilling activity, thus reducing the Company s accounts payable. A substantial amount of the payments made for capital expenditures thus far in 2009 has been for wells committed to, or which began drilling in fiscal 2008. Refundable income taxes declined as the Company s fiscal 2008 refund due was received during the quarter ended March 31, 2009. Prepayment of sales price on assets to be sold increased as the Company entered into an agreement to sell 67% of its leasehold interests in the Southeast Leedey field in Dewey County, Oklahoma effective July 1, 2009; in conjunction therewith, the Company received $2,514,343 as a full prepayment for the properties on June 26, 2009 (see NOTE 15: Subsequent Events).

The Company s operating cash flow for the first nine months of fiscal 2009 increased to $30,617,545, a 20% increase over the comparable period in fiscal 2008. Fiscal 2009 net cash provided by operating activities, as compared to fiscal 2008, increased primarily as a result of decreased oil and natural gas sales receivables, decreased refundable income taxes, decreased derivative contracts and increased non-cash items of depreciation, depletion and amortization and provision for impairment, partially offset by a decrease in deferred income taxes. Additions to properties and equipment for oil and natural gas activities during the 2009 period were $24,069,809 as compared to $29,625,707 in the 2008 period. Additions to properties and equipment are distinct from capital expenditures in that these additions include capital expenditures and net decrease (increase) in accounts payable for properties and equipment additions as reflected on the Statements of Cash Flows; therefore, additions to properties and equipment represent amounts added to properties and equipment in the period, whereas capital expenditures represent amounts paid in the period. Depressed natural gas prices are expected by management to continue through the remainder of fiscal 2009, resulting in reduced operating cash flows and lower drilling activity, which will result in reduced property and equipment additions for oil and natural gas activities. Management expects oil prices to remain relatively stable through the remainder of fiscal 2009; however, since over 80% of the Company s sales are from the sale of natural gas, oil prices have a marginal effect on the Company s cash flows. The Company does not operate any of its oil and natural gas properties and cannot control drilling activity on its mineral and leasehold acreage, thus low natural gas prices will likely continue to have a negative impact on the Company s drilling activity, making it extremely difficult for the Company to predict additions to properties and equipment with certainty. Therefore, based on management s assessment of current conditions, fiscal 2009 additions to property and equipment for oil and natural gas activities are projected to be approximately $32 million; whereas fiscal 2008 additions to property and equipment for oil and natural gas activities were approximately $53 million.

The industry-wide decline in drilling activity has also created downward pressure on the costs for drilling rigs, well equipment, and well services, which is expected to reduce the overall costs of drilling and completing wells. As lower natural gas prices continue to put downward pressure on drilling activity, and resulting production declines eventually occur, supply and demand is expected to come back into balance resulting in increased natural gas prices.

The Company historically funded capital additions, overhead costs and dividend payments primarily from operating cash flow. However, due to sharp decreases in oil and natural gas prices during fiscal 2009 and the increased expenditures for drilling in the prior two years, the Company has utilized its revolving line-of-credit facility to help fund these expenditures. The Company s strategy to minimize significant increases in borrowings will be to reduce its working interest participation in certain large ownership wells or by simply taking a no cost royalty interest in certain wells. By doing so, the Company

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reduces its capital expenditures and thereby limits borrowings, but still receives the benefit of a relatively high net revenue interest in new wells. Even with this strategy, and given current drilling activity, temporary moderate increases in borrowing can occur while the Company awaits the receipt of first revenues (which normally is 4 to 6 months after production begins) on recently completed wells. Several wells that have been recently completed will provide additional cash flow to the Company during the fourth quarter of fiscal 2009 as the first payments on these wells are received. Debt levels should remain reasonably stable through the remainder of fiscal 2009 as these first revenues are received and the effects of the managed drilling activity reduces cash expenditures. During the fiscal 2009 third quarter the Company was able to increase its borrowing base under its revolving credit facility from $25 million to $35 million, providing substantial availability of funds, should the need arise. The Company also is well within compliance on all of its debt covenants (current ratio, debt to EBITDA, tangible net worth and dividends as a percent of operating cash flow).

RESULTS OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2009 COMPARED TO THREE MONTHS ENDED JUNE 30, 2008

Overview:

The Company recorded a third quarter 2009 net loss of $928,512, or $.11 per share, as compared to a net income of $6,468,885 or $.76 per share in the 2008 quarter. The contributing factors to the recorded loss for the period are decreased revenue due to depressed oil and natural gas prices and increased DD&A. The increase in DD&A is the result of increased oil and natural gas production in the 2009 quarter and lower oil and natural gas reserves (resulting from significantly lower oil and natural gas prices in the 2009 quarter) as compared to the 2008 quarter. Expected reserves per well decrease when product prices decline as the lower prices result in wells reaching their economic limits earlier in time, thus shortening the wells economic lives and increasing the DD&A rate per mcfe of production.

Revenues:

Total revenues decreased $9,673,246 or 52% for the 2009 quarter. The decrease was the result of an $11,493,696 decrease in oil and natural gas sales partially offset by positive changes of $1,815,815 related to the fair value of natural gas derivative contracts. Lower revenues from oil and natural gas sales resulted from a decrease of 68% in natural gas sales prices to $2.96 per mcf and a decrease of 55% in oil sales prices to $53.89. Although sales prices steeply declined, the negative effect on revenues was mitigated by increases in both oil and natural gas sales volumes of 7% and 37%, respectively. The table below outlines the Company s sales volumes and average sales prices for oil and natural gas for the three month periods of fiscal 2009 and 2008:

| | BARRELS SOLD | AVERAGE PRICE | MCF SOLD | AVERAGE PRICE | MCFE SOLD | AVERAGE PRICE |
|---|---|---|---|---|---|---|
| Three months ended 6/30/09 | 34,145 | $ 53.89 | 2,442,604 | $ 2.96 | 2,647,474 | $ 3.42 |
| Three months ended 6/30/08 | 31,907 | $ 120.92 | 1,788,462 | $ 9.33 | 1,979,904 | $ 10.38 |

The increases in sales volumes are a result of successful drilling in the Company s core areas of the southeast Oklahoma Woodford Shale, the Fayetteville Shale in Arkansas and the Anadarko Basin in western Oklahoma where the Company participates in multiple plays. Contributing to the increased sales volumes, several new wells came on line during the fiscal 2009 quarter in these core areas. Drilling in these areas has, for the most part, stabilized at a relatively low level and is expected to result in fewer new wells coming on line during the remaining three months of fiscal 2009. This will limit the potential for sales volume increases during the last quarter of fiscal 2009.

Sales volumes by quarter for the last five quarters were as follows:

| Quarter ended | Barrels Sold | MCF Sold | MCFE Sold |
|---|---|---|---|
| 6/30/09 | 34,145 | 2,442,604 | 2,647,474 |
| 3/31/09 | 34,744 | 2,171,660 | 2,380,124 |
| 12/31/08 | 30,260 | 2,313,739 | 2,495,299 |

| | | | |
|---|---|---|---|
| 9/30/08 | 31,375 | 1,995,333 | 2,183,583 |
| 6/30/08 | 31,907 | 1,788,462 | 1,979,904 |

Gains (Losses) on Natural Gas Derivative Contracts:

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Fair value of derivative contracts as of June 30, 2009 was ($923,629) and $207,745 as of March 31, 2009. The Company had a net loss of $470,974 in the three months ended June 30, 2009 compared to a loss of $2,286,789 for the three months ended June 30, 2008. The Company received cash payments under the contracts of $660,400 during the 2009 quarter and made cash payments of $878,900 during the fiscal 2008 quarter.

Lease Operating Expenses (LOE):

LOE decreased $82,799 or 4% in the 2009 quarter. LOE per mcfe decreased to $.79 per mcfe in the 2009 quarter, as compared to $1.10 per mcfe in the 2008 quarter. Even though new wells continue to come on line, significantly lower value based fees (primarily gathering, compression and marketing costs) and lower field services and supplies costs combined to cause both an overall decrease in LOE and a decrease in LOE per mcfe in the 2009 quarter as compared to the 2008 quarter. The lower value based fees are primarily the result of lower natural gas prices; such fees are normally calculated as a percentage of sales value.

Production Taxes:

Production taxes decreased $305,404 or 45% in the 2009 quarter as compared to the 2008 quarter. The decline in production tax expense is the result of a 56% decrease in oil and natural gas sales revenues and production tax credits on horizontal wells drilled in the southeast Oklahoma Woodford Shale and the Fayetteville Shale in Arkansas.

Exploration Costs:

Exploration costs increased $77,143 or 218% in the 2009 quarter as compared to the 2008 quarter. The increase is related to a $54,440 increase in leasehold expiration and abandonment costs in the 2009 quarter as compared to the 2008 quarter. One dry hole was recorded in the 2009 quarter at a cost of approximately $23,000.

Depreciation, Depletion and Amortization (DD&A):

DD&A increased $2,173,620 or 47% in the 2009 quarter. DD&A per mcfe in the 2009 quarter was $2.59 as compared to $2.36 in the 2008 quarter. A 34% increase in mcfe produced in the 2009 quarter, vs. the 2008 quarter, accounts for approximately $1.6 million of the overall DD&A increase. The remaining increase of approximately $600,000 is attributable to lower oil and natural gas reserve volumes per well, resulting from lower oil and natural gas prices, and higher costs for horizontally drilled wells primarily in the Woodford and Fayetteville Shale areas. These same wells also account for the majority of the 2009 quarter s increase in natural gas production.

Provision for Impairment:

The provision for impairment increased $78,226 in the 2009 quarter. In the 2009 quarter one field was impaired a total of $115,892 as compared to the 2008 quarter which incurred impairment on one field totaling $37,666.

General and Administrative Costs (G&A):

G&A costs increased $9,572 or 1% in the 2009 quarter. The G&A cost variance is negligible between the 2009 and 2008 quarters. Personnel expenses increased $19,830 and legal expenses increased $38,751 in the 2009 quarter while shareholder and stock related expenses decreased $73,189.

Income Taxes:

The 2009 quarter incurred a benefit for income taxes of $1,073,000 as a result of a pre-tax loss of $2,001,512 as compared to a provision for income taxes of $3,018,000 in the 2008 quarter as a result of pre-tax income of $9,486,885. The resulting effective tax benefit rate in the 2009 quarter was 54% as compared to an effective tax provision rate of 32% in the 2008 quarter. The Company s utilization of excess percentage depletion (which is a permanent tax benefit) increased the tax benefit in the 2009 quarter, whereas it decreased the provision for income taxes in the 2008 quarter. The effect of this permanent tax benefit is that the effective tax rate is increased when recording a benefit for income taxes as in the fiscal 2009 quarter, while reducing the effective tax rate when recording a provision for income taxes as in the fiscal 2008 quarter. The benefit of excess percentage depletion is not directly related to the amount of a recorded loss or income. Accordingly, in cases where a recorded loss or income is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant.

NINE MONTHS ENDED JUNE 30, 2009 COMPARED TO NINE MONTHS ENDED JUNE 30, 2008

Overview:

The Company recorded a nine month period 2009 net loss of $2,748,397, or $.33 per share, as compared to a net income of $12,780,473 or $1.50 per share in the 2008 period. The recorded loss is primarily the result of decreased revenue caused by low oil and natural gas prices and an increase in DD&A. DD&A increased due to oil and natural gas production increases in the 2009 period and lower oil and natural gas reserves (resulting from significantly lower oil and natural gas prices in the 2009 period) as compared to the 2008 period. Expected reserves per well decrease when oil and natural gas prices decline as the lower prices result in wells reaching their economic limits earlier in time, thus shortening the wells economic lives and increasing the DD&A rate per mcfe of production.

Revenues:

Total revenues decreased $15,930,554 or 36% for the fiscal 2009 period as compared to the fiscal 2008 period. Lower revenues from oil and natural gas sales resulted from a 57% decrease in natural gas sales prices to $3.36 per mcf and a 51% decrease in oil sales prices to $48.81 per bbl. Although prices declined steeply, an increase in natural gas sales volumes of 40% partially offset the negative effect on revenues. The table below outlines the Company s sales volumes and average sales prices for oil and natural gas for the nine month periods of fiscal 2009 and 2008:

| | BARRELS SOLD | AVERAGE PRICE | MCF SOLD | AVERAGE PRICE | MCFE SOLD | AVERAGE PRICE |
|---|---|---|---|---|---|---|
| Nine months ended 6/30/09 | 99,149 | $ 48.81 | 6,928,003 | $ 3.36 | 7,522,897 | $ 3.74 |
| Nine months ended 6/30/08 | 101,027 | $ 100.12 | 4,932,704 | $ 7.82 | 5,538,866 | $ 8.79 |

The increases in natural gas sales volumes are a result of successful drilling in the Company s core areas of the southeast Oklahoma Woodford Shale, the Fayetteville Shale in Arkansas and the Anadarko Basin in western Oklahoma where the Company participates in multiple plays. Contributing to the increased natural gas sales volumes, several new wells came on line during the fiscal 2009 nine months in these core areas. Drilling in these areas has, for the most part, stabilized at a relatively low level and is expected to result in fewer new wells coming on line during the remaining three months of fiscal 2009. This will limit the potential for sales volume increases during the last quarter of fiscal 2009.

Gains (Losses) on Natural Gas Derivative Contracts:

The Company s fair value of derivative contracts was ($923,629) as of June 30, 2009 and $646,193 as of September 30, 2008. The Company had a net gain of $212,578 in the nine months ended June 30, 2009 compared to a loss of $4,391,316 for the nine months ended June 30, 2008. The Company received cash payments of $1,782,400 for the 2009 period and made payments of $777,900 for the 2008 period.

Lease Operating Expenses (LOE):

LOE increased $795,250 or 16% in the 2009 period as compared to the 2008 period. LOE per mcfe decreased in the fiscal 2009 period to $.77 per mcfe, as compared to $.90 per mcfe in the 2008 period. The accumulation of new wells which have come on line during the last year has resulted in an overall increase in LOE. The decrease on a per mcfe basis is due to the decrease in natural gas sales prices resulting in lower value based fees (primarily gathering and marketing costs) which are charged as a percent of natural gas sales, combined with declining prices for field services and supplies.

Production Taxes:

Production taxes decreased $1,314,125 or 54% in the 2009 period as compared to the 2008 period. The decline in production tax expense is the result of a 42% decrease in oil and natural gas sales revenues and production tax credits on horizontal wells drilled in the southeast Oklahoma Woodford Shale and the Fayetteville Shale in Arkansas.

Exploration Costs:

Exploration costs decreased $82,280 or 21% in the 2009 period as compared to the 2008 period. The decrease is primarily related to a decrease in leasehold expiration and abandonment costs in the 2009 period as compared to the 2008 period of approximately $150,000. Three dry holes were recorded in the 2009 period at a cost of approximately $59,000; no dry holes were recorded in the fiscal 2008 period.

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Depreciation, Depletion and Amortization (DD&A):

DD&A increased $7,506,059 or 56% in the 2009 period as compared to the 2008 period. DD&A was $2.78 per mcfe in the 2009 period as compared to $2.41 per mcfe in the 2008 period. A 36% increase in total mcfe produced in the 2009 period, vs. the 2008 period, accounts for approximately $4.8 million of the overall DD&A increase. The remaining increase of approximately $2.7 million is attributable to the increase in DD&A per mcfe which is related to lower oil and natural gas reserve volumes per well resulting from lower oil and natural gas prices, and higher costs for horizontally drilled wells primarily in the Woodford and Fayetteville Shale areas. These same wells also account for the majority of the 2009 period s increase in natural gas production.

Provision for Impairment:

The provision for impairment increased $1,738,461 in the 2009 period as compared to the 2008 period. Driven by depressed oil and natural gas prices, impairment has been recorded on 19 fields during the 2009 period in the amount of $2,124,133. Two of the fields accounted for $1,729,034 of the impairment, one field in Wheeler County, Texas consisting of one deep well (drilled in 2006 and had mechanical issues during completion which dramatically increased costs) was impaired $1,070,129 and one mature field in Beckham County, Oklahoma principally consisting of wells drilled in 2006 and prior was impaired $658,905. The Company did not incur any impairment in the three primary areas of operation (Woodford Shale area, Fayetteville Shale area and the Dill City project). During the 2008 period, seven fields were impaired a total of $385,672.

General and Administrative Costs (G&A):

G&A costs decreased $270,496 or 7% in the 2009 period as compared to the 2008 period due to decreased personnel related costs of approximately $378,000, which included a decrease in employee bonus costs of approximately $500,000 in the 2009 period (the result of beginning to ratably accrue for estimated 2008 annual employee bonuses during the 2008 fiscal period due to specific bonus performance criteria being established plus recording the full 2007 annual discretionary bonuses approved and paid during the 2008 fiscal period), partially offset by increases in legal fees of approximately $94,000.

Income Taxes:

The fiscal 2009 period incurred a benefit for income taxes of $2,278,000 as a result of a pre-tax loss of $5,026,397 as compared to a provision for income taxes of $6,317,000 in the fiscal 2008 period as a result of pre-tax income of $19,097,473. The resulting effective tax benefit rate in the fiscal 2009 period was 45% as compared to an effective tax provision rate of 33% in the fiscal 2008 period. The Company s utilization of excess percentage depletion (which is a permanent tax benefit) increased the tax benefit in the fiscal 2009 period, whereas it decreased the provision for income taxes in the fiscal 2008 period. The effect of this permanent tax benefit is that the effective tax rate is increased when recording a benefit for income taxes as in the fiscal 2009 period, while reducing the effective tax rate when recording a provision for income taxes as in the fiscal 2008 period. The benefit of excess percentage depletion is not directly related to the amount of a recorded loss or income. Accordingly, in cases where a recorded loss or income is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant. With the decline in product prices and forecasted loss in fiscal 2009, the Company established a valuation allowance on certain state tax net operating loss carryforwards (NOLs) for which the Company no longer believes are more likely than not to be realized prior to expiration. This reduced the benefit recognized during the respective period by $278,000.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by the Company generally do not change the Company s reported cash flows or liquidity. Generally, accounting rules do not involve a selection among alternatives, but involve a selection of the appropriate policies for applying the basic principles. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to the Company.

The more significant reporting areas impacted by management s judgments and estimates are crude oil and natural gas reserve estimation, impairment of assets, oil and natural gas sales revenue accruals and provision for income tax.

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Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, consultants and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known. The oil and natural gas sales revenue accrual is particularly subject to estimates due to the Company s status as a non-operator on all of its properties. Production information obtained from well operators is substantially delayed. This causes the estimation of recent production, used in the oil and natural gas revenue accrual, to be subject to some variations.

Oil and Natural Gas Reserves

Management considers the estimation of crude oil and natural gas reserves to be the most significant of its judgments and estimates. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company s calculation of depreciation, depletion and amortization, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company s consulting engineer (Pinnacle Energy Services, LLC), with assistance from Company staff, prepares estimates of crude oil and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. However, when significant oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing a price deck current with the period. Both DD&A and impairment were calculated in the 2009 quarter based on these updated reserve calculations. As required by the guidelines and definitions established by the SEC, these estimates are based on current crude oil and natural gas pricing held flat over the life of the properties. However, projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves used in formulating management s overall operating decisions. Based on the Company s fiscal 2008 DD&A, a 10% change in the DD&A rate per mcfe would result in a corresponding $1,978,466 annual change in DD&A expense. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method as oil and natural gas is produced. The Company s exploratory wells are all on-shore and primarily located in the mid-continent area. Generally, expenditures on exploratory wells comprise significantly less than 10% of the Company s total expenditures for oil and natural gas properties. This accounting method may yield significantly different operating results than the full cost method.

Impairment of Assets

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil and natural gas, future production costs, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The Company estimates future net cash flows on its oil and natural gas properties utilizing differentially adjusted forward pricing curves for both oil and natural gas and a discount rate in line with the discount rate used by the Company s bank to evaluate its properties. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and natural gas reserves. A further reduction in oil and natural gas prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded.

Oil and Natural Gas Sales Revenue Accrual

The Company does not operate any of its oil and natural gas properties. Drilling in the last two years has resulted in adding numerous wells with significantly larger interests, thus increasing the Company s production subject to accrual. On many of these wells the most current available production data is gathered from the appropriate operators and oil and natural gas index prices local to each well are used to more accurately estimate the accrual of revenue on these wells. Timely obtaining production data on all other wells from the operators is not feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil and natural gas. These variables could lead to an over or under accrual of oil and natural gas sales at the end of any particular quarter. Based on past history, the Company s estimated accrual has been materially accurate.

Income Taxes

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations as well as the completion of complex calculations, including the determination of the Company s percentage depletion deduction, if any. The excess percentage depletion calculation during interim periods represents a high-level estimate as the actual well-by-well calculation required cannot be performed until the end of the fiscal year. The Company has certain state net operating loss carryforwards (NOLs) that are recognized as tax assets when assessed as more likely than not to be utilized before their expiration dates. Criteria such as expiration dates, future excess state depletion and reversing taxable temporary differences are evaluated to determine whether the NOLs are more likely than not to be utilized before they expire. If any NOLs are determined to no longer be more likely than not to be utilized, then a valuation allowance is recognized to reduce the tax benefit of such NOLs. Although the Company s management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax matters.

The above description of the Company s critical accounting policies is not intended to be an all-inclusive discussion of the uncertainties considered and estimates made by management in applying accounting principles and policies. Results may vary significantly if different policies were used or required and if new or different information becomes known to management.

**ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The Company s revenue can be significantly impacted by changes in market prices for oil and natural gas. Based on the Company s fiscal 2008 production, a $.10 per mcf change in the price received for natural gas production would result in a corresponding $693,000 annual change in revenue. A $1.00 per barrel change in the price received for oil production would result in a corresponding $132,000 annual change in revenue. Cash flows could be impacted, to a lesser extent, by changes in the market interest rates related to the revolving credit facility which, as of June 30, 2009, bore interest at an annual variable interest rate equal to the national prime rate plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50%. At June 30, 2009, the Company had $13,332,504 outstanding under this facility. Based on total debt outstanding at June 30, 2009 a .5% change in interest rates would result in a $67,000 annual change in pre-tax operating cash flow.

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas prices. Volumes under such contracts do not exceed expected production. These arrangements cover only a portion of the Company s production and provide only partial price protection against declines in natural gas prices. These economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices (Refer to NOTE 11).

**ITEM 4 CONTROLS AND PROCEDURES**

The Company maintains disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company s President/Chief Executive Officer and Vice President/Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company s disclosure controls and procedures have been designed to meet, and management believes that they do meet, reasonable assurance standards. Based on their evaluation as of the end of the fiscal period covered by this report, the Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the Company s disclosure controls and procedures were effective.

There were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting made during the fiscal quarter or subsequent to the date the assessment was completed.

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**PART II OTHER INFORMATION**

**ITEM 6 EXHIBITS AND REPORT ON FORM 8-K**

| | | |
|---|---|---|
| (a) EXHIBITS | Exhibit 31.1 and 31.2 | Certification under Section 302 of the Sarbanes-Oxley Act of 2002 |
| | Exhibit 32.1 and 32.2 | Certification under Section 906 of the Sarbanes-Oxley Act of 2002 |
| | Exhibit 99 | Loan Agreement |

SIGNATURES

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

| | |
|---|---|
| | PANHANDLE OIL AND GAS INC. |
| August 10, 2009 | /s/ Michael C. Coffman |
| Date | Michael C. Coffman, President and Chief Executive Officer |
| August 10, 2009 | /s/ Lonnie J. Lowry |
| Date | Lonnie J. Lowry, Vice President and Chief Financial Officer |
| August 10, 2009 | /s/ Robb P. Winfield |
| Date | Robb P. Winfield, Controller and Chief Accounting Officer |

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