PANHANDLE OIL & GAS INC
Form 10-Q
May 10, 2016

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

FORM 10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the period ended	March 31, 2016

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
	(I.R.S. Employer

(State or other jurisdiction of incorporation or organization) Identification No.)

Grand Centre Suite 300, 5400 N Grand Blvd., Oklahoma City, Oklahoma 73112
(Address of principal executive offices)

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

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.
YesNo

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).
YesNo

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
Accelerated filer Non-accelerated filer Smaller reporting company

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

Outstanding shares of Class A Common stock (voting) at May 9, 2016:	16,582,380

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The following defined terms are used in this report:

“Bbl” barrel.

“Board” board of directors.

“BTU” British Thermal Units.

“Company” Panhandle Oil and Gas Inc.

“completion” the process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

“DD&A” depreciation, depletion and amortization.

“dry hole” exploratory or development well that does not produce crude oil and/or natural gas in economic quantities.

“EBITDA” earnings before interest, taxes, depreciation and amortization.

“ESOP” the Panhandle Oil and Gas Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan.

“exploratory well” a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.

“FASB” the Financial Accounting Standards Board.

“field” an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“G&A” general and administrative costs.

“gross acres” the total acres in which an interest is owned.

“held by production” or “HBP” an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

“horizontal drilling” a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

“IDC” intangible drilling costs.

“Independent Consulting Petroleum Engineer(s)” or “Independent Consulting Petroleum Engineering Firm” DeGolyer and MacNaughton of Dallas, Texas.

“LOE” lease operating expense.

“Mcf” thousand cubic feet.

“Mcfe” natural gas stated on an Mcf basis and crude oil and natural gas liquids converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil or natural gas liquids to six Mcf of natural gas.

“Mmbtu” million BTU.

“minerals”, “mineral acres” or “mineral interests” fee mineral acreage owned in perpetuity by the Company.

“net acres” the sum of the fractional interests owned in gross acres.

“NGL” natural gas liquids.

“NYMEX” New York Mercantile Exchange.

“Panhandle” Panhandle Oil and Gas Inc.

“play” term applied to identified areas with potential oil and/or natural gas reserves.

“proved reserves” the quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.

“royalty interest” well interests in which the Company does not pay a share of the costs to drill, complete and operate a well, but receives a much smaller proportionate share (as compared to a working interest) of production.

“SEC” the United States Securities and Exchange Commission.

“undeveloped acreage” lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

“working interest” well interests in which the Company pays a share of the costs to drill, complete and operate a well and receives a proportionate share of production.

“WTI” West Texas Intermediate.

Fiscal year references

All references to years in this report, unless otherwise noted, refer to the Company’s fiscal year end of September 30. For example, references to 2016 mean the fiscal year ended September 30, 2016.

References to oil and natural gas properties

References to oil and natural gas properties inherently include natural gas liquids associated with such properties.

PART 1 FINANCIAL INFORMATION

PANHANDLE OIL AND GAS INC.

CONDENSED BALANCE SHEETS

	March 31, 2016 (unaudited)	September 30, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 486,630	$ 603,915
Oil, NGL and natural gas sales receivables (net of allowance for uncollectable accounts)	4,231,534	7,895,591
Refundable income taxes	1,121,703	345,897
Refundable production taxes	454,018	476,001
Derivative contracts, net	330,751	4,210,764
Other	331,845	252,016
Total current assets	6,956,481	13,784,184
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	433,557,440	441,141,337
Non-producing oil and natural gas properties	7,643,408	8,293,997
Other	1,060,392	1,393,559
	442,261,240	450,828,893
Less accumulated depreciation, depletion and amortization	(240,429,941)	(228,036,803)
Net properties and equipment	201,831,299	222,792,090
Investments	167,663	2,248,999
Total assets	$ 208,955,443	$ 238,825,273
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 1,447,314	$ 2,028,746
Deferred income taxes	312,100	1,517,100
Accrued liabilities and other	936,629	1,330,901
Total current liabilities	2,696,043	4,876,747
Long-term debt	54,500,000	65,000,000
Deferred income taxes	32,918,907	39,118,907
Asset retirement obligations	2,895,488	2,824,944
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 16,863,004 issued at March 31, 2016, and September 30, 2015	280,938	280,938

Capital in excess of par value	3,000,554	2,993,119
Deferred directors' compensation	3,242,150	3,084,289
Retained earnings	113,871,183	125,446,473
	120,394,825	131,804,819
Less treasury stock, at cost; 280,624 shares at March 31, 2016, and 302,623 shares at September 30, 2015	(4,449,820)	(4,800,144)
Total stockholders' equity	115,945,005	127,004,675
Total liabilities and stockholders' equity	$ 208,955,443	$ 238,825,273

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

CONDENSED STATEMENTS OF OPERATIONS

	Three Months Ended March 31,		Six Months Ended March 31,	
	2016	2015	2016	2015
Revenues:	(unaudited)		(unaudited)	
Oil, NGL and natural gas sales	$ 6,136,186	$ 12,437,549	$ 15,191,474	$ 31,957,249
Lease bonuses and rentals	481,553	253,050	2,907,057	282,341
Gains (losses) on derivative contracts	975,113	1,900,162	940,177	13,150,427
Income (loss) from partnerships	(5,761)	88,273	10,508	288,187
	7,587,091	14,679,034	19,049,216	45,678,204
Costs and expenses:				
Lease operating expenses	3,187,353	4,376,996	6,753,889	9,162,346
Production taxes	229,140	399,157	550,981	1,021,669
Exploration costs	1,159	3,105	28,949	28,457
Depreciation, depletion and amortization	6,045,883	5,811,590	13,003,535	11,950,609
Provision for impairment	8,115,791	1,208,645	11,849,064	3,400,642
Loss (gain) on asset sales and other	27,134	(7,145)	(242,572)	(9,127)
Interest expense	342,348	409,276	702,910	812,009
General and administrative	1,651,444	1,850,203	3,563,523	3,808,631
Bad debt expense (recovery)	-	-	19,216	-
	19,600,252	14,051,827	36,229,495	30,175,236
Income (loss) before provision (benefit) for income taxes	(12,013,161)	627,207	(17,180,279)	15,502,968
Provision (benefit) for income taxes	(4,575,000)	(77,000)	(6,943,000)	4,565,000
Net income (loss)	$ (7,438,161)	$ 704,207	$ (10,237,279)	$ 10,937,968
Basic and diluted earnings (loss) per common share (Note 3)	$ (0.44)	$ 0.04	$ (0.61)	$ 0.65
Basic and diluted weighted average shares outstanding:				
Common shares	16,579,116	16,514,435	16,571,488	16,504,512
Unissued, directors' deferred compensation shares	259,381	266,066	258,206	265,503
	16,838,497	16,780,501	16,829,694	16,770,015
Dividends declared per share of common stock and paid in period	$ 0.04	$ 0.04	$ 0.08	$ 0.08

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

STATEMENTS OF STOCKHOLDERS’ EQUITY

Six Months Ended March 31, 2016

	Class A voting Common Stock Shares	Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2015	16,863,004	$ 280,938	$ 2,993,119	$ 3,084,289	$ 125,446,473	(302,623)	$ (4,800,144)	$ 127,004
Purchase of treasury stock	-	-	-	-	-	(7,477)	(117,165)	(117,16
Restricted stock awards	-	-	508,095	-	-	-	-	508,095
Net income (loss)	-	-	-	-	(10,237,279)	-	-	(10,237,
Dividends ($.08 per share)	-	-	-	-	(1,338,011)	-	-	(1,338,0
Distribution of restricted stock to officers and directors	-	-	(499,829)	-	-	28,759	456,117	(43,712)
Distribution of deferred directors' compensation	-	-	(831)	(10,541)	-	717	11,372	-
Increase in deferred directors' compensation charged to expense	-	-	-	168,402	-	-	-	168,402
Balances at March 31, 2016 (unaudited)	16,863,004	$ 280,938	$ 3,000,554	$ 3,242,150	$ 113,871,183	(280,624)	$ (4,449,820)	$ 115,945

Six Months Ended March 31, 2015

	Class A voting Common Stock Shares	Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2014	16,863,004	$ 280,938	$ 2,861,343	$ 3,110,351	$ 118,794,188	(372,364)	$ (5,858,167)	$ 119,188
Purchase of treasury stock	-	-	-	-	-	(7,177)	(120,611)	(120,61
Restricted stock awards	-	-	531,243	-	-	-	-	531,243
Net income (loss)	-	-	-	-	10,937,968	-	-	10,937,9
Dividends ($.08 per share)	-	-	-	-	(1,333,023)	-	-	(1,333,0
Distribution of restricted stock to officers and directors	-	-	(476,423)	-	-	26,533	417,665	(58,758)
Distribution of deferred directors' compensation	-	-	16,045	(328,415)	-	22,372	352,359	39,989
Increase in deferred directors' compensation charged to expense	-	-	-	169,464	-	-	-	169,464
Balances at March 31, 2015 (unaudited)	16,863,004	$ 280,938	$ 2,932,208	$ 2,951,400	$ 128,399,133	(330,636)	$ (5,208,754)	$ 129,354

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

CONDENSED STATEMENTS OF CASH FLOWS

	Six months ended March 31, 2016	2015
Operating Activities	(unaudited)	
Net income (loss)	$ (10,237,279)	$ 10,937,968
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	13,003,535	11,950,609
Impairment	11,849,064	3,400,642
Provision for deferred income taxes	(7,405,000)	2,698,000
Exploration costs	28,949	28,457
Gain from leasing fee mineral acreage	(2,906,480)	(281,124)
Net (gain) loss on sales of assets	(271,080)	-
Income from partnerships	(10,508)	(288,187)
Distributions received from partnerships	32,632	395,852
Directors' deferred compensation expense	168,402	169,464
Restricted stock awards	508,095	531,243
Bad debt expense (recovery)	19,216	-
Cash provided (used) by changes in assets and liabilities:		
Oil, NGL and natural gas sales receivables	3,644,841	6,588,410
Fair value of derivative contracts	3,880,013	(8,588,328)
Refundable production taxes	21,983	26,625
Other current assets	(79,829)	26,579
Accounts payable	(510,114)	(41,635)
Income taxes receivable	(775,806)	-
Income taxes payable	-	503,394
Accrued liabilities	(393,984)	(404,053)
Total adjustments	20,803,929	16,715,948
Net cash provided by operating activities	10,566,650	27,653,916
Investing Activities		
Capital expenditures, including dry hole costs	(2,554,543)	(19,797,996)
Acquisition of working interest properties	-	(308,180)
Proceeds from leasing fee mineral acreage	3,193,775	286,844
Investments in partnerships	48,462	(208,312)
Proceeds from sales of assets	627,547	-
Net cash provided (used) by investing activities	1,315,241	(20,027,644)
Financing Activities		
Borrowings under debt agreement	6,078,919	18,894,612

Payments of loan principal	(16,578,919)	(24,971,023)
Purchases of treasury stock	(117,165)	(120,611)
Payments of dividends	(1,338,011)	(1,333,023)
Excess tax benefit on stock-based compensation	(44,000)	(19,000)
Net cash provided (used) by financing activities	(11,999,176)	(7,549,045)
Increase (decrease) in cash and cash equivalents	(117,285)	77,227
Cash and cash equivalents at beginning of period	603,915	509,755
Cash and cash equivalents at end of period	$ 486,630	$ 586,982
Supplemental Schedule of Noncash Investing and Financing Activities:		
Additions to asset retirement obligations	$ 7,160	$ 32,728
Gross additions to properties and equipment	$ 2,483,225	$ 18,207,598
Net (increase) decrease in accounts payable for properties and equipment additions	71,318	1,898,578
Capital expenditures and acquisitions, including dry hole costs	$ 2,554,543	$ 20,106,176

(See accompanying notes)

PANHANDLE OIL AND GAS INC.

NOTES TO CONDENSED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1: Accounting Principles and Basis of Presentation

The accompanying unaudited condensed financial statements of Panhandle Oil and Gas Inc. have been prepared in accordance with the instructions to Form 10-Q as prescribed by the SEC. Management of the Company believes that all adjustments necessary for a fair presentation of the financial position and results of operations and cash flows for the periods have been included. All such adjustments are of a normal recurring nature. The 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 financial statements pursuant to the rules and regulations of the SEC. Therefore, these condensed financial statements should be read in conjunction with the financial statements and related notes thereto included in the Company's 2015 Annual Report on Form 10-K.

NOTE 2: Income Taxes

The Company's provision for income taxes differs from the statutory rate primarily due to estimated federal and state benefits generated from estimated excess federal and Oklahoma percentage depletion, which are permanent tax benefits. Excess percentage depletion, both federal and Oklahoma, can only be taken in the amount that it exceeds cost depletion which is calculated on a unit-of-production basis.

Both excess federal percentage depletion, which is limited to certain production volumes and by certain income levels, and excess Oklahoma percentage depletion, which has no limitation on production volume, reduce estimated taxable income or add to estimated taxable loss projected for any year. Due to the lower expected 2016 oil and natural gas prices, fiscal 2016 percentage depletion is not expected to significantly exceed cost depletion as in past years. Therefore, the permanent tax benefit in 2016 is not expected to be as significant as in 2015. The federal and Oklahoma excess percentage depletion estimates will be updated throughout the year until finalized with detailed well-by-well calculations at fiscal year-end. Federal and Oklahoma excess percentage depletion, when a provision for income taxes is recorded, decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is recorded. The benefits of federal and Oklahoma excess percentage depletion are not directly related to the amount of pre-tax income recorded in a period. Accordingly, in periods where a recorded pre-tax income or loss is relatively small, the proportional effect of these items on the effective tax rate may be significant. The effective tax rate for the six months ended March 31, 2016, was 40% as compared to 29% for the six months ended March 31, 2015. The effective tax rate for the quarter ended March 31, 2016, was 38% as compared to -12% for the quarter ended March 31, 2015. The lower estimated effective tax rate as of the end of the 2015 second quarter of 29%, as compared to 31% estimated at the end of the 2015 first quarter, resulted in a tax benefit recorded during the 2015 second quarter. When a tax benefit is recorded in a quarter with net income (as opposed to a net loss) before provision for income taxes, the result is a negative effective tax rate for the quarter, as was the case for the 2015 second quarter.

NOTE 3: Basic and Diluted Earnings (Loss) per Share

Basic and diluted 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' deferred compensation shares during the period.

NOTE 4: Long-term Debt

The Company has a $200,000,000 credit facility with a group of banks headed by Bank of Oklahoma (BOK) with a current borrowing base of $100,000,000 and a maturity date of November 30, 2018. The credit facility is subject to a semi-annual borrowing base determination, wherein BOK applies their commodity pricing forecast to the Company's reserve forecast and determines a borrowing base. The facility is secured by certain of the Company's properties with a net book value of $173,780,539 at March 31, 2016. The interest rate is based on BOK prime plus from 0.375% to 1.125%, or 30 day LIBOR plus from 1.875% to 2.625%. The election of BOK prime or LIBOR is at the Company's discretion. The interest rate spread from BOK prime or LIBOR will be charged based on the ratio of the loan balance to the borrowing base. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the borrowing base is advanced. At March 31, 2016, the effective interest rate was 2.67%.

The Company's debt is recorded at the carrying amount on its balance sheet. The carrying amount of the Company's revolving credit facility approximates fair value because the interest rates are reflective of market rates.

On December 10, 2015, the borrowing base was adjusted by the banks from $120,000,000 to $100,000,000.

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Determinations of the borrowing base are made semi-annually or whenever the banks, in their discretion, believe that there has been a material change in the value of the oil and natural gas properties. The loan agreement contains customary covenants which, among other things, require periodic financial and reserve reporting and place certain limits on the Company’s incurrence of indebtedness, liens, payment of dividends and acquisitions of treasury stock. In addition, the Company is required to maintain certain financial ratios, a current ratio (as defined) of no less than 1.0 to 1.0 and a funded debt to EBITDA (trailing twelve months as defined) of no more than 4.0 to 1.0. At March 31, 2016, the Company was in compliance with the covenants of the loan agreement and has $45,500,000 of availability under its outstanding credit facility.

NOTE 5: Deferred Compensation Plan for Non-Employee Directors

Annually, non-employee directors may elect to be included in the Deferred Compensation Plan for Non-Employee Directors. The Deferred Compensation Plan for Non-Employee Directors provides that each outside director may individually elect to be credited with future unissued shares of Company common stock rather than cash for all or a portion of the annual retainers, Board meeting fees and committee meeting fees, and may elect to receive shares, when issued, over annual time periods up to ten years. These unissued shares are recorded to each director’s deferred compensation account at the closing market price of the shares (i) on the dates of the Board and committee meetings, and (ii) on the payment dates of the annual retainers. Only upon a director’s retirement, termination, death, or a change-in-control of the Company will the shares recorded for such director under the Deferred Compensation Plan for Non-Employee Directors be issued to the director. The promise to issue such shares in the future is an unsecured obligation of the Company.

NOTE 6: Restricted Stock Plan

In March 2010, shareholders approved the Panhandle Oil and Gas Inc. 2010 Restricted Stock Plan (2010 Stock Plan), which made available 200,000 shares of common stock to provide a long-term component to the Company’s total compensation package for its officers and to further align the interest of its officers with those of its shareholders. In March 2014, shareholders approved an amendment to increase the number of shares of common stock reserved for issuance under the 2010 Stock Plan from 200,000 shares to 500,000 shares and to allow the grant of shares of restricted stock to our directors. The 2010 Stock Plan, as amended, is designed to provide as much flexibility as possible for future grants of restricted stock so that the Company can respond as necessary to provide competitive compensation in order to retain, attract and motivate directors and officers of the Company and to align their interests with those of the Company’s shareholders.

Effective in May 2014, the board of directors adopted resolutions to allow management, at their discretion, to purchase the Company’s common stock up to an amount equal to the aggregate number of shares of common stock awarded pursuant to the Company’s Amended 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

On December 9, 2015, the Company awarded 13,482 non-performance based shares and 40,446 performance based shares of the Company's common stock as restricted stock to certain officers. The restricted stock vests at the end of a three-year period and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The non-performance and performance based shares had a fair value on their award date of $223,397 and $376,915, respectively. The Company recognized $211,363 of compensation expense on the award date for performance based shares for officers that were eligible for retirement. The remaining fair value for the performance based awards as well as the entire fair value of the non-performance based awards will be recognized as compensation expense ratably over the vesting period. The fair value of the performance based shares on their award date is calculated by simulating the Company's stock prices as compared to the Dow Jones Select Oil Exploration and Production Index (DJSOEP) prices utilizing a Monte Carlo model covering the performance period (December 9, 2015, through December 9, 2018).

On December 31, 2015, the Company awarded 12,996 non-performance based shares of the Company's common stock as restricted stock to its non-employee directors. The restricted stock vests quarterly over one year starting on March 31, 2016. The restricted stock contains nonforfeitable rights to receive dividends and voting rights during the vesting period. These non-performance based shares had a fair value on their award date of $210,018.

The following table summarizes the Company's pre-tax compensation expense for the three and six months ended March 31, 2016 and 2015, related to the Company's performance based and non-performance based restricted stock.

	Three Months Ended March 31,		Six Months Ended March 31,	
	2016	2015	2016	2015
Performance based, restricted stock	$ 40,380	$ 255,132	$ 309,890	$ 319,306
Non-performance based, restricted stock	96,308	111,000	198,205	211,937
Total compensation expense	$ 136,688	$ 366,132	$ 508,095	$ 531,243

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A summary of the Company's unrecognized compensation cost for its unvested performance based and non-performance based restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	As of March 31, 2016	
	Unrecognized Compensation Cost	Weighted Average Period (in years)
Performance based, restricted stock	$ 288,621	2.07
Non-performance based, restricted stock	497,028	1.73
Total	$ 785,649	

Upon vesting, shares are expected to be issued out of shares held in treasury.

NOTE 7: Oil, NGL and Natural Gas Reserves

Management considers the estimation of the Company's crude oil, NGL and natural gas reserves to be the most significant of its judgments and estimates. Changes in crude oil, NGL and natural gas reserve estimates affect the Company's calculation of DD&A, provision for retirement of assets and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares estimates of crude oil, NGL and natural gas reserves based on available geological 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. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing appropriate prices for the current period. The estimated oil, NGL and natural gas reserves were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil, NGL and natural gas price for each month within the 12-month period prior to the balance sheet date, held flat over the life of the properties. However, projected future crude oil, NGL and natural gas pricing assumptions are used by management to prepare estimates of crude oil, NGL and natural gas reserves and future net cash flows used in asset impairment assessments and in formulating management's overall operating decisions. Crude oil, NGL and natural gas prices are volatile and affected by worldwide production and consumption and are outside the control of management.

NOTE 8: 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 drilling and completion costs; future sales prices for oil, NGL and natural gas; future production costs; estimates of future oil, NGL 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, NGL and natural gas reserves. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations to reflect any material changes since the prior report was issued and then utilizes updated projected future price decks current with the period. For the three months ended March 31, 2016 and 2015, the assessment resulted in impairment provisions on producing properties of $8,115,791 and $1,208,645, respectively. For the six months ended March 31, 2016 and 2015, the assessment resulted in impairment provisions on producing properties of $11,849,064 and $3,400,642, respectively. The impairment provisions for the three and six months ended March 31, 2016, are principally the result of lower projected future prices for oil, NGL and natural gas. A further reduction in oil, NGL and natural gas prices or a decline in reserve volumes may lead to additional impairment in future periods that may be material to the Company.

NOTE 9: Capitalized Costs

As of March 31, 2016, and September 30, 2015, non-producing oil and natural gas properties include costs of $0 and $1,762, respectively, on exploratory wells which were drilling and/or testing.

NOTE 10: Derivatives

The Company has entered into commodity price derivative agreements including fixed swap contracts and costless collar contracts. These instruments are intended to reduce the Company’s exposure to short-term fluctuations in the price of oil and natural gas. Fixed swap contracts set a fixed price and provide 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. Collar contracts set a fixed floor price and a fixed ceiling price and provide 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. These contracts cover only a portion of the Company’s natural gas and oil production and provide only partial price protection against declines in natural gas and oil prices. These derivative instruments may expose the Company to risk of financial loss and limit the benefit of future increases in prices. All of the Company's derivative contracts are with Bank of Oklahoma and are secured under its credit facility with Bank of Oklahoma. The derivative instruments have settled or will settle based on the prices below.

Derivative contracts in place as of March 31, 2016

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
December 2015 - May 2016	80,000 Mmbtu	NYMEX Henry Hub	$2.50 floor / $3.10 ceiling
January - September 2016	80,000 Mmbtu	NYMEX Henry Hub	$2.15 floor / $2.50 ceiling
April - October 2016	200,000 Mmbtu	NYMEX Henry Hub	$1.95 floor / $2.40 ceiling
June - September 2016	80,000 Mmbtu	NYMEX Henry Hub	$2.15 floor / $2.90 ceiling
November 2016 - March 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.25 floor / $3.65 ceiling
Natural gas fixed price swaps			
January - September 2016	80,000 Mmbtu	NYMEX Henry Hub	$2.43
Oil costless collars			
April - September 2016	10,000 Bbls	NYMEX WTI	$37.50 floor / $44.00 ceiling
April - September 2016	5,000 Bbls	NYMEX WTI	$37.50 floor / $46.50 ceiling
July - December 2016	3,000 Bbls	NYMEX WTI	$35.00 floor / $49.00 ceiling

Derivative contracts in place as of September 30, 2015

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
January - December 2015	100,000 Mmbtu	NYMEX Henry Hub	$3.50 floor / $4.10 ceiling
January - December 2015	70,000 Mmbtu	NYMEX Henry Hub	$3.25 floor / $4.00 ceiling
April - October 2015	50,000 Mmbtu	NYMEX Henry Hub	$3.50 floor / $4.00 ceiling
May - October 2015	70,000 Mmbtu	NYMEX Henry Hub	$3.50 floor / $3.95 ceiling

Oil costless collars			
July - December 2015	10,000 Bbls	NYMEX WTI	$80.00 floor / $86.50 ceiling
Oil fixed price swaps			
April - December 2015	5,000 Bbls	NYMEX WTI	$94.56
July - December 2015	7,000 Bbls	NYMEX WTI	$93.91

The Company has elected not to complete all of the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges. The Company's fair value of derivative contracts was a net asset of $330,751 as of March 31, 2016, and a net asset of $4,210,764 as of September 30, 2015.

The fair value amounts recognized for the Company's derivative contracts executed with the same counterparty under a master netting arrangement may be offset. The Company has the choice to offset or not, but that choice must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for the derivative contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Balance Sheets.

The following table summarizes and reconciles the Company's derivative contracts' fair values at a gross level back to net fair value presentation on the Company's Condensed Balance Sheets at March 31, 2016, and September 30, 2015. The Company has offset all amounts subject to master netting agreements in the Company's Condensed Balance Sheets at March 31, 2016, and September 30, 2015.

	March 31, 2016		September 30, 2015
	Fair Value (a)		Fair Value (a)
	Commodity Contracts		Commodity Contracts
	Current Assets	Current Liabilities	Current Assets
Gross amounts recognized	$ 384,176	$ 53,425	$ 4,210,764
Offsetting adjustments	(53,425)	(53,425)	-
Net presentation on Condensed Balance Sheets	$ 330,751	$ -	$ 4,210,764

(a) See Fair Value Measurements section for further disclosures regarding fair value of financial instruments.

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

NOTE 11: Fair Value Measurements

Fair value is defined 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. 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.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2016.

	Fair Value Measurement at March 31, 2016			
	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	$ -	$ 164,201	$ -	$ 164,201
Derivative Contracts - Collars	$ -	$ -	$ 166,550	$ 166,550

Level 2 – Market Approach - The fair values of the Company's swaps are based on a third-party pricing model which utilizes inputs that are either readily available in the public market, such as natural gas curves, or can be corroborated from active markets. These values are based upon future prices, time to maturity and other factors. These values are then compared to the values given by our counterparties for reasonableness.

Level 3 – The fair values of the Company's costless collar contracts are based on a pricing model which utilizes inputs that are unobservable or not readily available in the public market. These values are based upon future prices, volatility, time to maturity and other factors. These values are then compared to the values given by our counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts. An increase (decrease) in the volatility of oil and natural gas prices will decrease (increase) the fair value of oil and natural gas derivatives and adverse changes to our counterparties' creditworthiness will decrease the fair value of our derivatives.

The following table represents quantitative disclosures about unobservable inputs for Level 3 Fair Value Measurements.

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value March 31, 2016
Oil Collars	Oil price volatility curve	17.76% - 34.22%	23.96%	$ (42,572)
Natural Gas Collars	Natural gas price volatility curve	0% - 36.52%	18.88%	$ 209,122

A reconciliation of the Company's derivative contracts classified as Level 3 measurements is presented below. All gains and losses are presented on the Gains (losses) on derivative contracts line item on our Statement of Operations.

	Derivatives
Balance of Level 3 as of October 1, 2015	$ 1,891,249
Total gains or (losses)	
Included in earnings	(4,006,829)
Included in other comprehensive income (loss)	-
Purchases, issuances and settlements	2,282,130
Transfers in and out of Level 3	-
Balance of Level 3 as of March 31, 2016	$ 166,550

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Quarter Ended March 31,			
	2016		2015	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties (a)	$ 6,589,196	$ 8,115,791	$ 1,510,458	$ 1,208,645

	Six Months Ended March 31,			
	2016		2015	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties (a)	$ 9,741,650	$ 11,849,064	$ 3,833,218	$ 3,400,642

(a) At the end of each quarter, the Company assesses the carrying value of its producing properties for impairment. This assessment utilizes estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of future oil and natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs and an applicable discount rate commensurate with risk of the underlying cash flow estimates. These assessments identified certain properties with carrying value in excess of their calculated fair values.

At March 31, 2016, and September 30, 2015, the fair value of financial instruments approximated their carrying amounts. Financial instruments include long-term debt, which the valuation is classified as Level 3 and is based on a valuation technique that requires inputs that are both unobservable and significant to the overall fair value measurement. The fair value measurement of our long-term debt is valued using a discounted cash flow model that calculates the present value of future cash flows pursuant to the terms of the debt agreements and applies estimated current market interest rates. The estimated current market interest rates are based primarily on interest rates currently being offered on borrowings of similar amounts and terms. In addition, no valuation input adjustments were considered necessary relating to nonperformance risk for the debt agreements.

NOTE 12: Recently Issued Accounting Pronouncements

In May 2014, the FASB issued Accounting Standard Update 2014-09, Revenue from Contracts with Customers, which will supersede nearly all existing revenue recognition guidance under GAAP. The standard’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. We are evaluating our existing revenue recognition policies to determine whether any contracts in the scope of the guidance will be affected by the new requirements. The standard is effective for us on October 1, 2018. The standard allows for either “full retrospective” adoption, meaning the standard is applied to all of the periods presented, or “modified retrospective” adoption, meaning the standard is applied only to the most current period presented in the financial statements. We are currently evaluating the transition method that will be elected.

In April 2015, the FASB issued an accounting standards update on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. This update is not expected to have a material impact on our financial statements.

In August 2015, the FASB issued an accounting standards update which allows for line-of-credit arrangements to be handled consistently with the presentation of debt issuance costs update issued in April 2015. For public entities, the guidance is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. This update is not expected to have a material impact on our financial statements.

In November 2015, the FASB issued an accounting standards update on the presentation of deferred income tax assets and liabilities. The update requires that deferred income tax assets and liabilities be classified as noncurrent in the balance sheet. For public entities, the guidance is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. This update is not expected to have a material impact on our financial statements.

In January 2016, the FASB issued Accounting Standards Update No. 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. The new guidance is intended to improve the recognition and measurement of financial instruments. The new guidance is effective for public companies for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. We are assessing the potential impact that this update will have on our financial statements.

In February 2016, the FASB issued its new lease accounting guidance in Accounting Standards Update No. 2016-02, Leases (Topic 842). Under the new guidance, lessees will be required to recognize the following for all leases (with the exception of short-term leases) at the commencement date: 1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and 2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The new lease guidance simplified the accounting for sale and leaseback transactions primarily because lessees must recognize lease assets and lease liabilities. Lessees will no longer be provided with a source of off-balance sheet financing. For public entities, the guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities upon issuance. Lessees (for capital and operating leases) and lessors (for sales-type, direct financing, and operating leases) must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The modified retrospective approach would not require any transition accounting for leases that expired before the earliest comparative period presented. Lessees and lessors may not apply a full retrospective transition approach. This update is not expected to have a material impact on our financial statements.

In March 2016, the FASB has issued Accounting Standards Update No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The new guidance is intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public entities, the guidance is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted for any organization in any interim or annual period. We are assessing the potential impact that this update will have on our 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 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 2016 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, NGL 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, NGL and natural gas reserves. Investors should also read the other information in this Form 10-Q and the Company’s 2015 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

The Company had positive working capital of $4,260,438 at March 31, 2016, compared to $8,907,437 at September 30, 2015.

Liquidity:

Cash and cash equivalents were $486,630 as of March 31, 2016, compared to $603,915 at September 30, 2015, a decrease of $117,285. Cash flows for the six months ended March 31 are summarized as follows:

Net cash provided (used) by:	2016	2015	Change
Operating activities	$ 10,566,650	$ 27,653,916	$ (17,087,266)
Investing activities	1,315,241	(20,027,644)	21,342,885
Financing activities	(11,999,176)	(7,549,045)	(4,450,131)
Increase (decrease) in cash and cash equivalents	$ (117,285)	$ 77,227	$ (194,512)

Operating activities:

Net cash provided by operating activities decreased $17,087,266 during the 2016 period, as compared to the 2015 period, the result of the following:

- Receipts of oil, NGL and natural gas sales (net of production taxes and gathering, transportation and marketing costs) and other decreased $19,378,618.

- Decreased income tax payments of $78,563.

· Increased net receipts on derivative contracts of $258,091.

· Decreased interest payments of $110,885.

· Decreased payments for G&A and other expenses of $371,673.

· Decreased payments for field operating expenses of $1,472,140.

Investing activities:

Net cash used by investing activities decreased $21,342,885 during the 2016 period, as compared to the 2015 period, due to:

· A decrease in cash used to acquire properties of $308,180.

· Lower payments for drilling and completion activity during 2016 decreased capital expenditures by $17,243,453.

· Increased receipts from leasing of fee mineral acreage of $2,906,931.

· Increased proceeds from sales of assets of $627,547.

Financing activities:

Net cash used by financing activities increased $4,450,131 during the 2016 period, as compared to the 2015 period, the result of the following:

· During the period ended March 31, 2016, net borrowings decreased $10,500,000; during the period ended March 31, 2015, net borrowings decreased $6,076,411.

Capital Resources:

Capital expenditures to drill and complete wells decreased $17,243,453 (87%) from the 2015 to the 2016 period. There continues to be no drilling activity on the Company's acreage in the Eagle Ford Shale oil play in South Texas and in the Arkansas Fayetteville Shale natural gas play. Well proposals which meet our participation criteria in the Company's other plays continue to be extremely low. These decreases in drilling activity have resulted in the 87% decline in capital expenditures. Due to the continuation of low oil, NGL and natural gas prices, 2016 capital expenditures to drill and complete wells are expected to be significantly less than in 2015.

Oil, NGL and natural gas production volumes decreased 18% on an Mcfe basis during the 2016 period, as compared to the 2015 period. The extremely low drilling activity as noted above resulted in new production coming on line falling considerably short of replacing the natural decline of existing wells. Oil production decreased 15% and was principally the result of the natural decline in production from the Eagle Ford Shale in South Texas. To a lesser extent, declining production from several smaller fields in Oklahoma, Texas and New Mexico also contributed to the decrease. The decrease was partially offset by production from five Eagle Ford Shale and five North Dakota Bakken Shale wells that were placed on production during the second half of 2015. Natural gas production decreased 17%, largely the result of the natural decline in production from the Fayetteville Shale in Arkansas and the southeastern Oklahoma Woodford Shale. Associated natural gas production from the western Oklahoma horizontal Granite Wash and Marmaton oil plays, along with decreased production from eight additional fields in Oklahoma and Texas also contributed to the decline. NGL production decreased 29%, primarily the result of declining production in the Anadarko Basin Woodford Shale and Granite Wash fields. Production declines in the Eagle Ford Shale and western Oklahoma Marmaton were also part of the decline. Production from five Eagle Ford Shale wells and five North Dakota Bakken Shale wells (placed on production during the second half of 2015) partially offset the decline. Due to the natural production decline of existing wells, combined with expected low capital expenditures to drill and complete new wells during 2016, we expect oil, NGL and natural gas production to experience a higher rate of decline during 2016 than was experienced in 2015.

Since the Company is not the operator of any of its oil and natural gas properties, it is extremely difficult for us to predict levels of future participation in the drilling and completion of new wells and their associated capital expenditures. This makes 2016 capital expenditures for drilling and completion projects difficult to forecast.

Even at the lower levels of expected production and product prices during 2016, the Company expects to generate cash flows sufficient to fund expected capital expenditures, dividends and any treasury stock purchases. The Company did receive lease bonus payments during the first half of 2016 totaling approximately $3.2 million, and has received approximately $2.7 million thus far during the 2016 third quarter. The cash flow benefit from bonus payments associated with the leasing of drilling rights on the Company's mineral acreage is very difficult to project as the Company's mineral acreage position is so diverse and spread across several states. Excess cash will be used to reduce debt.

With continued oil and natural gas price volatility, management continues to evaluate opportunities for product price protection through additional hedging of the Company's future oil and natural gas production. See NOTE 10 –

“Derivatives” for a complete list of the Company’s outstanding derivative contracts.

The use of the Company’s cash provided by operating activities and resultant change to cash is summarized in the table below:

	Six months ended March 31, 2016
Cash provided by operating activities	$ 10,566,650
Cash provided (used) by:	
Capital expenditures - drilling and completion of wells	(2,554,543)
Quarterly dividends of $.08 per share	(1,338,011)
Treasury stock purchases	(117,165)
Net borrowings (payments) on credit facility	(10,500,000)
Other investing and financing activities	3,825,784
Net cash used	(10,683,935)
Net increase (decrease) in cash	$ (117,285)

Outstanding borrowings on the credit facility at March 31, 2016, were $54,500,000.

Looking forward, the Company expects to fund overhead costs, capital additions related to the drilling and completion of wells, treasury stock purchases, if any, and dividend payments primarily from cash provided by operating

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activities and cash on hand. As management evaluates opportunities to acquire additional assets, additional borrowings utilizing our bank credit facility could be necessary. Also, during times of oil, NGL and natural gas price decreases, or increased capital expenditures, it could be necessary to utilize the credit facility further in order to fund these expenditures. The Company has availability ($45,500,000 at March 31, 2016) under its revolving credit facility and is in compliance with its debt covenants (current ratio, debt to trailing 12-month EBITDA, as defined, and dividends as a percent of operating cash flow). Non-cash expenses (such as impairment) are excluded from the EBITDA calculation. The debt covenants require a maximum ratio of the Company's debt to EBITDA of 4:1. As of March 31, 2016, the debt to EBITDA ratio was 1.75:1.

The borrowing base under the credit facility is scheduled to be redetermined in June 2016. As product prices are currently lower than the levels used in the December 2015 redetermination, management expects the borrowing base to be set lower than $100 million, but at a level that will continue to provide ample liquidity for the Company to continue to employ its normal operating strategies.

In future periods, should product price expectations continue to decline below levels seen at March 31, 2016, impairment charges significantly greater than the Company has incurred in prior periods could result. The most significant field that could be affected is the Eagle Ford Shale in Texas which has a net book value of approximately $93 million. This field, which predominantly produces oil, is approximately 39% developed with over 100 well locations remaining to be drilled over the next several years.

Based on expected capital expenditure levels and anticipated cash provided by operating activities for 2016, the Company has sufficient liquidity to fund its ongoing operations and, combined with availability under its credit facility, to fund acquisitions, if any.

RESULTS OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2016 – COMPARED TO THREE MONTHS ENDED MARCH 31, 2015

Overview:

The Company recorded a second quarter 2016 net loss of $7,438,161, or $0.44 per share, as compared to net income of $704,207, or $0.04 per share, in the 2015 quarter. The decrease in net income was principally the result of decreased oil, NGL and natural gas sales, increases in DD&A and impairment and decreased gains on derivative contracts; partially offset by increased benefit from income taxes, decreased LOE and increases in lease bonuses and rentals. These items are further discussed below.

Oil, NGL and Natural Gas Sales:

Oil, NGL and natural gas sales decreased $6,301,363 or 51% for the 2016 quarter. Oil, NGL and natural gas sales were down due to decreases in oil, NGL and natural gas sales volumes of 21%, 22% and 19%, respectively, and decreases in oil, NGL and natural gas prices of 40%, 29% and 38%, respectively. The following table outlines the Company's production and average sales prices for oil, NGL and natural gas for the three month periods of fiscal 2016 and 2015:

	Oil Bbls Sold	Average Price	Mcf Sold	Average Price	NGL Bbls Sold	Average Price	Mcfe Sold	Average Price
Three months ended								
3/31/2016	90,760	$ 27.19	2,014,139	$ 1.64	37,934	$ 9.85	2,786,303	$ 2.20
3/31/2015	114,567	$ 45.67	2,475,777	$ 2.64	48,681	$ 13.82	3,455,265	$ 3.60

The oil production decrease is principally the result of the natural production decline from the Eagle Ford Shale in South Texas. To a lesser extent, declining production from twelve fields in Oklahoma, Texas and New Mexico also contributed to the decrease. The decrease was partially offset by production from five Eagle Ford Shale wells plus five North Dakota Bakken Shale wells that were placed on production during the second half of 2015. The decrease in natural gas production was largely the result of declining production from both the Fayetteville Shale in Arkansas and the southeastern Oklahoma Woodford Shale. Associated natural gas production from the western Oklahoma horizontal Granite Wash and Marmaton oil plays contributed to the decline. The decrease was partially offset by production from new wells in the Anadarko Woodford Shale. The NGL production decrease primarily resulted from declining production in the Anadarko Basin Granite Wash and Woodford Shale fields. To a lesser extent, the Eagle Ford Shale and western Oklahoma Marmaton also contributed to the declines. The decrease was somewhat offset by production from five Eagle Ford Shale and five North Dakota Bakken Shale wells that were placed on production during the second half of 2015.

The Company anticipates that the current reduced level of capital expenditures will continue as long as oil, NGL and natural gas prices remain at or near their current depressed levels. As a result of natural production decline of existing wells, combined with expected low capital expenditures to drill and complete new wells during 2016, we expect oil, NGL and natural gas production to continue to experience a higher rate of decline in the remainder of 2016 than was experienced in 2015.

Production for the last five quarters was as follows:

Quarter ended	Oil Bbls Sold	Mcf Sold	NGL Bbls Sold	Mcfe Sold
3/31/2016	90,760	2,014,139	37,934	2,786,303
12/31/2015	106,362	2,216,922	48,051	3,143,400
9/30/2015	112,237	2,261,236	47,738	3,221,086
6/30/2015	109,738	2,407,049	41,737	3,315,899
3/31/2015	114,567	2,475,777	48,681	3,455,265

Lease Bonuses and Rentals:

Lease bonuses and rentals increased $228,503 in the 2016 quarter. The increase was mainly due to the Company leasing mineral acres in Dewey County, Oklahoma, in the 2016 quarter.

Gains (Losses) on Derivative Contracts:

The fair value of derivative contracts was a net asset of $330,751 as of March 31, 2016, and a net asset of $10,490,170 as of March 31, 2015. We had a net gain on derivative contracts of $975,113 in the 2016 quarter as compared to a net gain of $1,900,162 in the 2015 quarter. The change is principally due to the oil and natural gas collars and fixed price swaps being more beneficial in the 2015 quarter, as NYMEX oil and natural gas futures had fallen further below the floor of the collars and the fixed prices of the swaps.

Lease Operating Expenses (LOE):

LOE decreased $1,189,643 or 27% in the 2016 quarter. LOE per Mcfe decreased in the 2016 quarter to $1.14 compared to $1.27 in the 2015 quarter. LOE related to field operating costs decreased $934,281 in the 2016 quarter compared to the 2015 quarter, a 33% decrease. Field operating costs were $.68 per Mcfe in the 2016 quarter as compared to $.82 per Mcfe in the 2015 quarter. The decrease in rate in the 2016 quarter is principally the result of operating efficiencies gained in the Eagle Ford Shale field due to the addition of a salt water disposal system and electrification of the field.

The decrease in LOE related to field operating costs was coupled with a decrease in handling fees (primarily gathering, transportation and marketing costs) of $255,362 in the 2016 quarter compared to the 2015 quarter. On a per Mcfe basis, these fees were $.46 in the 2016 quarter as compared to $.45 in the 2015 quarter. Natural gas sales bear the large majority of the handling fees while oil sales incur a much smaller amount. Handling fees are charged either as a percent of sales or based on production volumes.

Depreciation, Depletion and Amortization (DD&A):

DD&A increased $234,293 or 4% in the 2016 quarter. DD&A in the 2016 quarter was $2.17 per Mcfe as compared to $1.68 per Mcfe in the 2015 quarter. DD&A increased $1,359,455 as a result of this $.49 increase in the DD&A rate per Mcfe. An offsetting decrease of $1,125,162 was the result of production decreasing 19% in the 2016 quarter compared to the 2015 quarter. The rate increase is mainly due to lower oil, NGL and natural gas prices utilized in the reserve calculations during the 2016 quarter, as compared to 2015 quarter, shortening the economic life of wells thus resulting in lower projected remaining reserves on a significant number of wells causing increased units of production DD&A.

Provision for Impairment:

The provision for impairment increased $6,907,146 in the 2016 quarter as compared to the 2015 quarter. During the 2016 quarter, impairment of $8,115,791 was recorded on twenty-eight fields. Three oil and liquids rich fields accounted for approximately $7.4 million (Anadarko Basin Granite Wash - $5.9 million, Permian Basin - $.9 million and Marietta Basin Woodford - $.6 million) of the impairment mainly due to continued declining oil, NGL and natural gas prices. During the 2015 quarter, impairment of $1,208,645 was recorded on fifteen fields.

Income Taxes:

Benefit for income taxes increased in the 2016 quarter by $4,498,000, the result of a $12,640,368 decrease in pre-tax income in the 2016 quarter, compared to the 2015 quarter, and an increase in the effective tax rate from -12% in the 2015 quarter to 38% in the 2016 quarter. When a provision for income taxes is recorded, federal and Oklahoma excess percentage depletion decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is recorded, as was the case for the 2016 quarter. The lower estimated effective tax rate as of the end of the 2015 second quarter of 29%, as compared to 31% estimated at the end of the 2015 first quarter, resulted in a tax benefit recorded during the 2015 second quarter. When a tax benefit is recorded in a quarter with net income (as opposed to a net loss) before provision for income taxes, the result is a negative effective tax rate for the quarter, as was the case for the 2015 second quarter.

SIX MONTHS ENDED MARCH 31, 2016 – COMPARED TO SIX MONTHS ENDED MARCH 31, 2015

Overview:

The Company recorded a six month net loss of $10,237,279, or $0.61 per share, in the 2016 period, as compared to net income of $10,937,968, or $0.65 per share, in the 2015 period. The decrease in net income was principally the result of decreased oil, NGL and natural gas sales, decreased gains on derivative contracts and increases in provision for impairment and DD&A; partially offset by decreased income taxes, increases in lease bonuses and rentals, and decreased production taxes and LOE. These items are further discussed below.

Oil, NGL and Natural Gas Sales:

Oil, NGL and natural gas sales decreased $16,765,775 or 52% for the 2016 period. Oil, NGL and natural gas sales were down due to a decrease in oil, NGL and natural gas sales volumes of 15%, 29% and 17%, respectively, and decreases in oil, NGL and natural gas prices of 42%, 46% and 43%, respectively. The following table outlines the Company's production and average sales prices for oil, NGL and natural gas for the six month periods of fiscal 2016 and 2015:

	Oil Bbls Sold	Average Price	Mcf Sold	Average Price	NGL Bbls Sold	Average Price	Mcfe Sold	Average Price
Six months ended								
3/31/2016	197,122	$ 33.75	4,231,061	$ 1.78	85,985	$ 11.49	5,929,703	$ 2.56
3/31/2015	231,150	$ 58.38	5,076,938	$ 3.13	121,485	$ 21.23	7,192,748	$ 4.44

The oil production decrease is principally the result of the natural production decline from the Eagle Ford Shale in South Texas. To a lesser extent, declining production from several smaller fields in Oklahoma, Texas and New Mexico also contributed to the decrease. The decrease was partially offset by production from five Eagle Ford Shale wells plus five North Dakota Bakken Shale wells that were placed on production during the second half of 2015. The decrease in natural gas production was largely the result of declining production from both the Fayetteville Shale in Arkansas and the southeastern Oklahoma Woodford Shale. Associated natural gas production from the western Oklahoma horizontal Granite Wash and Marmaton oil plays, along with decreased production from eight additional fields in Oklahoma and Texas also contributed to the decline. The NGL production decrease primarily resulted from declining production in the Anadarko Basin Woodford Shale and Granite Wash fields. To a lesser extent, the Eagle Ford Shale and western Oklahoma Marmaton also contributed to the declines. The decrease was partially offset by production from five Eagle Ford Shale wells plus five North Dakota Bakken Shale wells that were placed on production during the second half of 2015.

The Company anticipates that the current reduced level of capital expenditures will continue as long as oil, NGL and natural gas prices remain at or near their current depressed levels. As a result of natural production decline of existing wells, combined with expected low capital expenditures to drill and complete new wells during 2016, we expect oil, NGL and natural gas production to continue to experience a higher rate of decline in the remainder of 2016 than was experienced in 2015.

Lease Bonuses and Rentals:

Lease bonuses and rentals increased $2,624,716 in the 2016 period. The increase was mainly due to the Company leasing 4,057 net mineral acres in Cochran County, Texas, 972 net mineral acres in Woodward County, Oklahoma, and 254 net mineral acres in Dewey County, Oklahoma, in the 2016 period.

Gains (Losses) on Derivative Contracts:

The fair value of derivative contracts was a net asset of $330,751 as of March 31, 2016, and a net asset of $10,490,170 as of March 31, 2015. We had a net gain on derivative contracts of $940,177 in the 2016 period as compared to a net gain of $13,150,427 recorded in the 2015 period. The change is principally due to the oil and natural gas collars and fixed price swaps being more beneficial in the 2015 period, as NYMEX oil and natural gas futures had fallen further below the floor of the collars and the fixed prices of the swaps.

Lease Operating Expenses (LOE):

LOE decreased $2,408,457 or 26% in the 2016 period. LOE per Mcfe decreased in the 2016 period to $1.14 compared to $1.27 in the 2015 period. LOE related to field operating costs decreased $1,662,887 in the 2016 period compared to the 2015 period, a 29% decrease. Field operating costs were $.70 per Mcfe in the 2016 period as compared to $.81 per Mcfe in the 2015 period. The decrease in rate in the 2016 period is principally the result of operating efficiencies gained in the Eagle Ford Shale field due to the addition of a salt water disposal system and electrification of the field, as well as fewer workovers.

The decrease in LOE related to field operating costs was coupled with a decrease in handling fees (primarily gathering, transportation and marketing costs) of $745,570 in the 2016 period compared to the 2015 period. The decrease in the amount in the 2016 period is the result of decreased oil and gas production and sales. On a per Mcfe basis, these fees decreased $.02 due mainly to a 17% decrease in natural gas production versus a 15% decrease in oil production. Natural gas sales bear the large majority of the handling fees while oil sales incur a much smaller amount. Handling fees are charged either as a percent of sales or based on production volumes.

Production Taxes:

Production taxes decreased $470,688 or 46% in the 2016 period as compared to the 2015 period. The decrease in amount is primarily the result of decreased oil, NGL and natural gas sales of $16,765,775 during the 2016 period. Production taxes as a percentage of oil, NGL and natural gas sales were 3.6% for the 2016 period and 3.2% for the 2015 period. The increase in tax rate is the result of the expiration of production tax discounts on a number of the Company’s horizontally drilled wells in Oklahoma and Arkansas, as well as the increased proportionate sales coming from Texas and North Dakota where initial tax rates are higher.

Depreciation, Depletion and Amortization (DD&A):

DD&A increased $1,052,926 or 9% in the 2016 period. DD&A in the 2016 period was $2.19 per Mcfe as compared to $1.66 per Mcfe in the 2015 period. DD&A increased $3,151,450 as a result of this $.53 increase in the DD&A rate per Mcfe. An offsetting decrease of $2,098,524 was the result of production decreasing 18% in the 2016 period compared to the 2015 period. The rate increase is mainly due to lower oil, NGL and natural gas prices utilized in the reserve calculations during the 2016 period, as compared to 2015 period, shortening the economic life of wells thus resulting in lower projected remaining reserves on a significant number of wells causing increased units of production DD&A.

Provision for Impairment:

The provision for impairment increased $8,448,422 in the 2016 period compared to the 2015 period. During the 2016 period, impairment of $11,849,064 was recorded on thirty-nine fields. Four oil and liquids rich fields accounted for approximately $9.5 million (Anadarko Basin Granite Wash - $5.9 million, Cheyenne West - $1.7 million, Ellis County Marmaton - $1.0 million and Permian Basin - $.9 million) of the impairment mainly due to continued declining oil, NGL and natural gas prices. During the 2015 period, impairment of $3,400,642 was recorded on nineteen fields. One oil field in Hemphill County, Texas, accounted for $1,846,488 of the impairment due mainly to declining oil prices.

Income Taxes:

Provision for income taxes decreased in the 2016 period by $11,508,000, the result of a $32,683,247 decrease in pre-tax income in the 2016 period compared to the 2015 period. The effective tax rate for the 2016 and 2015 periods was 40% and 29%, respectively. When a provision for income taxes is recorded, federal and Oklahoma excess percentage depletion decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is recorded, as was the case for the 2016 period.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Critical accounting policies are those the Company believes are most important to portraying its financial conditions and results of operations and also require the greatest amount of subjective or complex judgments by management. Judgments and uncertainties regarding the application of these policies may result in materially different amounts being reported under various conditions or using different assumptions. There have been no material changes to the critical accounting policies previously disclosed in the Company’s Form 10-K for the fiscal year ended September 30, 2015.

ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Oil, NGL and natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of oil, NGL and natural gas price trends, and there remains a rather wide divergence in the opinions held in the industry. The Company can be significantly impacted by changes in oil and natural gas prices. The market price of oil, NGL and natural gas in 2016 will impact the amount of cash generated from operating activities, which will in turn impact the level of the Company's capital expenditures and production. Excluding the impact of the Company's 2016 derivative contracts, the price sensitivity in 2016 for each $0.10 per Mcf change in wellhead natural gas price is $974,522 for operating revenue based on the Company's prior year natural gas volumes. The price sensitivity in 2016 for each $1.00 per barrel change in wellhead oil price is $453,125 for operating revenue based on the Company's prior year oil volumes.

Commodity Price Risk

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas and oil prices. The Company does not enter into these derivatives for speculative or trading purposes. All of our outstanding derivative contracts are with Bank of Oklahoma and are secured. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in natural gas and oil prices. These derivative contracts expose the Company to risk of financial loss and limit the benefit of future increases in prices. For the Company's natural gas fixed price swaps, a change of $.10 in the NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $48,000. For the Company's natural gas collars, a change of $.10 in the NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $172,000. For the Company's oil collars, a change of $1.00 in the NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $73,000.

Financial Market Risk

Operating income could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company's credit facilities. The revolving loan bears interest at the BOK prime rate plus from 0.375% to 1.125%, or 30 day LIBOR plus from 1.875% to 2.625%. At March 31, 2016, the Company had $54,500,000 outstanding under this facility and the effective interest rate was 2.67%. At this point, the Company does not believe that its liquidity has been materially affected by the interest rate uncertainties noted in the last few years and the Company does not believe that its liquidity will be significantly impacted in the near future.

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 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, subject to the limitations noted above, the Company's disclosure controls and procedures were effective to ensure material information relating to the Company is made known to them. 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.

PART II OTHER INFORMATION

ITEM 2 UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the three months ended March 31, 2016, the Company did not repurchase shares of the Company's common stock.

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan in March 2010, as amended in March 2014, the Board of Directors approved repurchase of up to $1.5 million of the Company's common stock, from time to time, up to an amount equal to the aggregate number of shares of common stock awarded pursuant to the Company's Amended 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors. Pursuant to previously adopted board resolutions, the purchase of an additional $1.5 million of the Company's common stock became authorized and approved effective June 26, 2013. The shares are held in treasury and are accounted for using the cost method. Effective May 14, 2014, the Board adopted resolutions to allow management to repurchase the Company's common stock at their discretion.

ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) The annual meeting of shareholders was held on March 10, 2016.

(b) Two directors (Robert O. Lorenz and Robert E. Robotti) were elected for three-year terms at the meeting. The directors elected and the results of voting were as follows:

Directors	SHARES FOR	WITHHELD
Robert O. Lorenz	10,227,539	84,662
Robert E. Robotti	10,214,714	97,487

(c) Two proposals were also voted upon (i) a proposal to ratify the appointment of Ernst & Young, LLP as our independent registered public accounting firm for the fiscal year ending September 30, 2016, and (ii) an advisory vote on executive compensation.

	SHARES FOR	AGAINST	ABSTAINING
Proposal (i)	13,266,237	58,562	47,694
Proposal (ii)	8,873,946	466,162	972,093

ITEM 6 EXHIBITS

(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 101.INS – XBRL Instance Document
Exhibit 101.SCH – XBRL Taxonomy Extension Schema Document
Exhibit 101.CAL – XBRL Taxonomy Extension Calculation Linkbase Document
Exhibit 101.LAB – XBRL Taxonomy Extension Labels Linkbase Document
Exhibit 101.PRE – XBRL Taxonomy Extension Presentation Linkbase Document
Exhibit 101.DEF – XBRL Taxonomy Extension Definition Linkbase Document

(b) Form 8-K Dated (3/11/16), item 5.07 – Submission of Matters to a Vote of Security Holders

Form 8-K	Dated (3/15/16), item 5.02 – Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers
Form 8-K/A	Dated (3/16/16), item 5.02 – Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers

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.

	PANHANDLE OIL AND GAS INC.
May 9, 2016 Date	/s/ Michael C. Coffman Michael C. Coffman, President and Chief Executive Officer
May 9, 2016 Date	/s/ Lonnie J. Lowry Lonnie J. Lowry, Vice President and Chief Financial Officer
May 9, 2016 Date	/s/ Robb P. Winfield Robb P. Winfield, Controller and Chief Accounting Officer

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