PANHANDLE OIL & GAS INC
Form 10-K
December 12, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2017

Commission File Number: 001-31759

PANHANDLE OIL AND GAS INC.

(Exact name of registrant as specified in its charter)

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

Grand Centre, Suite 300, 5400 N. Grand Blvd.

Oklahoma City, OK (Address of principal executive offices)	73112 (Zip code)

Registrant's telephone number: (405) 948-1560

Securities registered under Section 12(b) of the Act:

CLASS A COMMON STOCK (VOTING) (Title of Class)	NEW YORK STOCK EXCHANGE (Name of each exchange on which registered)

Securities registered under Section 12(g) of the Act:
(Title of Class)

CLASS B COMMON STOCK (NON-VOTING) $1.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934. Yes X No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes X No

(Facing Sheet Continued)

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. X Yes No

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Securities Exchange Act of 1934. (Check one):

Large accelerated filer Accelerated filer X Non-accelerated filer Smaller reporting company Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. Yes No

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes X No

The aggregate market value of the voting stock held by non-affiliates of the registrant, computed by using the $19.20 per share closing price of registrant's Common Stock, as reported by the New York Stock Exchange at March 31, 2017, was $297,276,077. As of December 1, 2017, 16,678,016 shares of Class A Common Stock were outstanding. As of December 1, 2017, there were no shares of Class B Common Stock outstanding.

Documents Incorporated By Reference

The information required by Part III of this Report, to the extent not set forth herein, is incorporated by reference from the registrant's Definitive Proxy Statement relating to the annual meeting of stockholders to be held on March 7, 2018. The definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

T A B L E   O F   C O N T E N T S

DEFINITIONS

The following defined terms are used in this report:

Bbl – barrel.

Bcf – billion cubic feet.

Bcfe – natural gas stated on a Bcf basis and crude oil and natural gas liquids converted to a billion cubic feet of natural gas equivalent by using the ratio of one million Bbl of crude oil or natural gas liquids to six Bcf of natural gas.

Board – board of directors.

BTU – British Thermal Units.

CEO – Chief Executive Officer.

CFO – Chief Financial Officer.

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.

conventional – an area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

DD&A – depreciation, depletion and amortization.

developed acreage – the number of acres allocated or assignable to productive wells or wells capable of production.

development well – a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

dry gas – natural gas that remains in a gaseous state in the reservoir and does not produce large quantities of liquid hydrocarbons when brought to the surface. Also may refer to gas that has been processed or treated to remove a majority of natural gas liquids.

dry hole – exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

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.

formation – a layer of rock, which has distinct characteristics that differ from nearby rock.

G&A – general and administrative expenses.

gross acres or gross wells – the total acres or wells in which a working interest is owned.

held by production or HBP – refers to 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.

hydraulic fracturing – a process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production.

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.

Mcfd – thousand cubic feet per day.

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.

Mmcf – million cubic feet.

Mmcfe – natural gas stated on an Mmcf basis and crude oil and natural gas liquids converted to a million cubic feet of natural gas equivalent by using the ratio of one thousand Bbl of crude oil or natural gas liquids to six Mmcf of natural gas.

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

net acres or net wells – the sum of the fractional working interests owned in gross acres or gross wells.

NGL – natural gas liquids.

NYMEX – New York Mercantile Exchange.

OPEC – Organization of Petroleum Exporting Countries.

Panhandle – Panhandle Oil and Gas Inc.

PDP – proved developed producing.

play – term applied to identified areas with potential oil, NGL and/or natural gas reserves.

production or produced – volumes of oil, NGL and natural gas that have been both produced and sold.

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.

proved developed reserves – reserves expected to be recovered through existing wells with existing equipment and operating methods.

proved undeveloped reserves or PUD – proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

PV-10 – estimated pre-tax present value of future net revenues discounted at 10% using SEC rules.

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 smaller proportionate share (as compared to a working interest) of production.

SEC – the United States Securities and Exchange Commission.

unconventional – an area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but may lack readily apparent traps, seals and discrete hydrocarbon water boundaries that typically define conventional reservoirs. These areas tend to have low permeability and may be closely associated with source rock, as is the case with oil and gas shale, tight oil and gas sands, and coalbed methane, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production.

undeveloped acreage – 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.

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 2017 mean the fiscal year ended September 30, 2017.

References to oil and natural gas properties

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

PART I

ITEM 1 BUSINESS
GENERAL

Panhandle Oil and Gas Inc. was founded in Range, Texas County, Oklahoma, in 1926, as Panhandle Cooperative Royalty Company. The Company operated as a cooperative until 1979, when it merged into Panhandle Royalty Company, and its shares became publicly traded. On April 2, 2007, the Company's name was changed to Panhandle Oil and Gas Inc.

While operating as a cooperative, the Company distributed most of its net income to shareholders as cash dividends. Upon conversion to a public company in 1979, although still paying dividends, the Company began to retain a substantial part of its cash flow to participate with a working interest in the drilling of wells on its mineral acreage and to purchase additional mineral acreage. Several acquisitions of additional mineral and leasehold acreage and small companies were made from 1980 to the present time.

The Company is involved in the acquisition, management and development of non-operated oil and natural gas properties, including wells located on the Company's mineral and leasehold acreage. Panhandle's mineral and leasehold properties are located primarily in Arkansas, New Mexico, North Dakota, Oklahoma and Texas. The majority of the Company's oil, NGL and natural gas production is from wells located in Arkansas, Oklahoma and Texas.

In March 2007, the Company increased its authorized Class A Common Stock from 12 million shares to 24 million shares. On October 8, 2014, the Company split its Class A Common Stock on a 2-for-1 basis.

The Company's office is located at Grand Centre, Suite 300, 5400 N. Grand Blvd., Oklahoma City, OK 73112; telephone – (405) 948-1560; facsimile – (405) 948-2038. The Company's website is www.panhandleoilandgas.com.

The Company files periodic reports with the SEC on Forms 10-Q and 10-K. These forms, the Company's annual report to shareholders and current press releases are available free of charge on our website as soon as reasonably practicable after they are filed with the SEC or made available to the public. Also, the Company posts copies of its various corporate governance documents on the website. From time to time, the Company posts other important disclosures to investors in the "Press Release" or "Upcoming Events" section of the website, as allowed by SEC rules.

Materials filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding the Company that has been filed electronically with the SEC, including this Form 10-K.

BUSINESS STRATEGY

Most of Panhandle's revenues are derived from the production and sale of oil, NGL and natural gas (see Item 8 - "Financial Statements and Supplementary Data"). The Company's oil and natural gas properties, including its mineral acreage, leasehold acreage and working and royalty interests in producing wells are located primarily in Arkansas, New Mexico, North Dakota, Oklahoma and Texas (see Item 2 – "Properties"). Exploration and development of the Company's oil and natural gas properties are conducted in association with oil and natural gas exploration and production companies, primarily larger independent companies. The Company does not operate any of its oil and natural gas properties, but has been an active working interest participant for many years in wells drilled on the Company's mineral acres and leasehold. The majority of the Company's drilling participations are on properties located in unconventional plays in Arkansas, Oklahoma and Texas.

PRINCIPAL PRODUCTS AND MARKETS

The Company's principal products, in order of revenue generated, are natural gas, crude oil and NGL. These products are sold to various purchasers, including pipeline and marketing companies, which service the areas where the Company's producing wells are located. Since the Company does not operate any of the wells in which it owns an interest, it relies on the operating expertise of numerous companies that operate wells in which the Company owns interests. This includes expertise in the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of production from the wells. Oil, NGL and natural gas sales are principally handled by the well operator. Payment for oil, NGL and natural gas sold is received by the Company from the well operator or the contracted purchaser.

Prices of oil, NGL and natural gas are dependent on numerous factors beyond the control of the Company, including supply and demand, competition, weather, international events and circumstances, actions taken by OPEC, and economic, political and regulatory developments. Since demand for natural gas is subject to weather conditions, prices received for the Company's natural gas production are subject to seasonal variations.

The Company enters into price risk management financial instruments (derivatives) to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. The derivative contracts apply only to a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative contracts expose the Company to risk of financial loss and may limit the benefit of future increases in oil and natural gas prices. Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts.

COMPETITIVE BUSINESS CONDITIONS

The oil and natural gas industry is highly competitive, particularly in the search for new oil, NGL and natural gas reserves. Many factors affect Panhandle's competitive position and the market for its products, which are beyond its control. Some of these factors include: the quantity and price of foreign oil imports; domestic supply of oil, NGL and natural gas; changes in prices received for oil, NGL and natural gas production; business and consumer demand for refined oil products, NGL and natural gas; and the effects of federal, state and local regulation of the exploration for, production of and sales of oil, NGL and natural gas (see Item 1A – "Risk Factors"). Changes in any of these factors can have a dramatic influence on the price Panhandle receives for its oil, NGL and natural gas production.

The Company does not operate any of the wells in which it has an interest; rather it relies on companies with greater resources, staff, equipment, research and experience for operation of wells in both the drilling and production phases. The Company's business strategy is to use its strong financial base and its mineral and leasehold acreage ownership, coupled with its own geologic and economic evaluations, either to elect to participate in drilling operations with these companies or to lease or farmout its mineral or leasehold acreage while retaining a royalty interest. This strategy allows the Company to compete effectively in expensive and complex drilling operations it could not undertake on its own with limited capital and staffing.

SOURCES AND AVAILABILITY OF RAW MATERIALS

The existence of economically recoverable oil, NGL and natural gas reserves in commercial quantities is crucial to the ultimate realization of value from the Company's mineral and leasehold acreage. These mineral and leasehold properties are essentially the raw materials to our business. The production and sale of oil, NGL and natural gas from the Company's properties are essential to provide the cash flow necessary to sustain the ongoing viability of the Company. When it is evaluated to be beneficial to share value, the Company purchases oil and natural gas mineral and leasehold acreage to assure the continued availability of acreage with which to participate in exploration and development drilling operations and, subsequently, to produce and sell oil, NGL and natural gas. This participation in exploration, development and production activities and purchase of additional acreage is necessary to continue to supply the Company with the raw materials with which to generate additional cash flow. Mineral and leasehold acreage purchases are made from many owners. The Company does not rely on any particular companies or persons for the purchases of additional mineral and leasehold acreage.

MAJOR CUSTOMERS

The Company's oil, NGL and natural gas production is sold, in most cases, through its well operators to many different purchasers. During 2017, sales through two separate well operators accounted for approximately 18% and 13% of the Company's total oil, NGL and natural gas sales. During 2016, sales through two separate well operators accounted for approximately 23% and 12% of the Company's total oil, NGL and natural gas sales. During 2015, sales through two separate well operators accounted for approximately 23% and 14% of the Company's total oil, NGL and natural gas sales. Generally, if one purchaser declines to continue purchasing the Company's production, several other purchasers can be located. Pricing is generally consistent from purchaser to purchaser.

PATENTS, TRADEMARKS, LICENSES, FRANCHISES AND ROYALTY AGREEMENTS

The Company does not own any patents, trademarks, licenses or franchises. Royalty agreements on wells producing oil, NGL and natural gas generate a portion of the Company's revenues. These royalties are tied to ownership of mineral acreage, and this ownership is perpetual, unless sold by the Company. Royalties are due and payable to the Company whenever oil, NGL or natural gas is produced and sold from wells located on the Company's mineral acreage.

REGULATION

All of the Company's well interests and non-producing properties are located onshore in the contiguous United States. The Company's oil and natural gas properties are subject to various taxes, such as gross production taxes and, in some cases, ad valorem taxes.

States require permits for drilling operations, drilling bonds and reports concerning operations and impose other regulations relating to the exploration for and production of oil, NGL and natural gas. These states also have regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties and the regulation of spacing, plugging and abandonment of wells. These regulations vary from state to state. As previously discussed, the Company must rely on its well operators to comply with governmental regulations.

ENVIRONMENTAL MATTERS

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local laws and regulations regarding environmental and ecological matters. Compliance with these laws and regulations may necessitate significant capital outlays. The Company does not believe the existence of these environmental laws, as currently written and interpreted, will materially hinder or adversely affect the Company's business operations; however, there can be no assurances made regarding future events, changes in laws, or the interpretation of laws governing our industry. For example, current discussions regarding future governance of hydraulic fracturing could have a material impact on the Company. Several states and local municipalities have adopted or are considering adopting regulations that could impose more stringent requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. The Oklahoma Corporation Commission has ordered the shut-in of some saltwater disposal wells and reductions of injected volumes in others in northern Oklahoma where these wells are proximal to seismic activity. The Company is currently experiencing insignificant impact and anticipates insignificant future impact from these shut-ins and injection volume reductions due to our minimal working interest ownership in this area. Since the Company does not operate any wells in which it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. As such, the Company has no knowledge of any instances of non-compliance with existing laws and regulations. Absent an extraordinary event, any noncompliance is not likely to have a material adverse effect on the financial condition of the Company. The Company maintains insurance coverage at levels which are customary in the industry, but is not fully insured against all environmental risks.

EMPLOYEES

At September 30, 2017, Panhandle employed 21 people with four of the employees serving as executive officers. The President and CEO is also a director of the Company.

ITEM 1A RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company's business and future prospects. If any of the following risk factors should occur, the Company's financial condition could be materially impacted, and the holders of our securities could lose part or all of their investment in Panhandle. The risk factors described below are not exhaustive, and investors are encouraged to perform their own investigation with respect to the Company and its business. Investors should also read the other information in this Form 10-K, including the financial statements and related notes.

Uncertainty of economic conditions, worldwide and in the United States, may have a significant negative effect on operating results, liquidity and financial condition.

Effects of change in domestic and international economic conditions could include: (1) an imbalance in supply and demand for oil, NGL and natural gas resulting in decreased oil, NGL and natural gas reserves due to curtailed drilling activity; (2) a decline in oil, NGL and natural gas prices; (3) risk of insolvency of well operators and oil, NGL and natural gas purchasers; (4) limited availability of certain insurance coverage; (5) limited access to derivative instruments; and (6) limited credit availability. A decline in reserves would lead to a decline in production, and either a production decline, or a decrease in oil, NGL and natural gas prices, would have a negative impact on the Company's cash flow, profitability and value.

Oil, NGL and natural gas prices are volatile. Volatility in these prices can adversely affect operating results and the price of the Company's common stock. This volatility also makes valuation of oil and natural gas producing properties difficult and can disrupt markets.

The supply of and demand for oil, NGL and natural gas impact the prices we realize on the sale of these commodities and, in turn, materially affect the Company's financial results. Oil, NGL and natural gas prices have historically been, and will likely continue to be, volatile. The prices for oil, NGL and natural gas are subject to wide fluctuation in response to a number of factors, including:

- worldwide economic conditions
- economic, political, regulatory and tax developments
- market uncertainty
- changes in the supply of and demand for oil, NGL and natural gas
- availability and capacity of necessary transportation and processing facilities
- commodity futures trading

(5)

- regional price differentials
- differing quality of oil produced (i.e., sweet crude versus heavy or sour crude)
- differing quality and NGL content of natural gas produced
- weather conditions
- the level of imports and exports of oil, NGL and natural gas
- political instability or armed conflicts in major oil and natural gas producing regions
- actions taken by OPEC or other major oil, NGL and natural gas producing or consuming countries
- competition from alternative sources of energy
- technological advancements affecting energy consumption and energy supply

Price volatility makes it difficult to budget and project the return on investment in exploration and development projects and to estimate with precision the value of producing properties that are owned or acquired by the Company. In addition, volatile prices often disrupt the market for oil and natural gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Revenues, results of operations, reserves and capital availability may fluctuate significantly as a result of variations in oil, NGL and natural gas prices and production performance.

Lower oil, NGL and natural gas prices may also trigger significant impairment write-downs on a portion of the Company’s properties which negatively affect the Company’s results of operations. In addition, the credit available under its credit facility is affected by product prices.

Low oil, NGL and natural gas prices for a prolonged period of time would have a material adverse effect on the Company.

The Company’s financial position, results of operations, access to capital and the quantities of oil, NGL and natural gas that may be economically produced would be negatively impacted if oil, NGL and natural gas prices are low for an extended period of time. The ways in which low prices could have a material negative effect include:

- significantly decrease the number of wells drilled by operators on the Company’s acreage, thereby reducing our production and cash flows
- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves and maintain or increase production
- future undiscounted and discounted net cash flows from producing properties would decrease, possibly resulting in recognition of impairment expense

- certain reserves may no longer be economic to produce, leading to lower proved reserves, production and cash flow
- access to sources of capital, such as equity and debt markets, could be severely limited or unavailable
- the Company may incur a reduction in the borrowing base on its credit facility

The Company cannot control activities on its properties.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over the third-party operators of these properties. Our dependence on the third-party operators of our properties, and on the cooperation of other working interest owners in these properties, could negatively affect the following:

- the Company's return on capital used in drilling or property acquisition
- the Company's production and reserve growth rates
- capital required to drill and complete wells
- success and timing of drilling, development and exploitation activities on the Company's properties
- compliance with environmental, safety and other regulations
- lease operating expenses
- plugging and abandonment costs, including well-site restorations

Dependency on each operator's judgment, expertise and financial resources could result in unexpected future costs, lost revenues and/or capital restrictions, to the extent they would cumulatively have a material adverse effect on the Company's financial position and results of operations.

The Company's derivative activities may reduce the cash flow received for oil and natural gas sales.

In order to manage exposure to price volatility on our oil and natural gas production, we enter into oil and natural gas derivative contracts for a portion of our expected production. Oil and natural gas price derivatives may limit the cash flow we actually realize and therefore reduce the Company's ability to fund future projects. None of our oil and natural gas price derivative contracts are designated as hedges for accounting purposes; therefore, all changes in fair value of derivative contracts are reflected in earnings. Accordingly, these fair values may vary significantly from period to period, materially affecting reported earnings. The fair value of our oil and natural gas derivative instruments outstanding as of September 30, 2017, was a net asset of $516,159.

There is risk associated with our derivative contracts that involves the possibility that counterparties may be unable to satisfy contractual obligations to us. If any counterparty to our derivative instruments were to default or seek bankruptcy protection, it could subject a larger percentage of our future oil and natural gas production to commodity price changes and could have a negative effect on our ability to fund future projects.

Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding derivative contracts.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on us and our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market including swap clearing and trade execution requirements. New or modified rules, regulations or requirements may increase the cost and availability to the counterparties of our hedging and swap positions which they can make available to us, as applicable, and may further require the counterparties to our derivative instruments to spin off some of their derivative activities to separate entities which may not be as creditworthy as the current counterparties. Any changes in the regulations of swaps may result in certain market participants deciding to curtail or cease their derivative activities.

While many rules and regulations have been promulgated and are already in effect, other rules and regulations remain to be finalized or effectuated, and therefore, the impact of those rules and regulations on us is uncertain at this time. The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives that we use to hedge against commodity price fluctuations (including through requirements to post collateral), (ii) materially alter the terms of derivative contracts, (iii) reduce the availability of derivatives to protect against risks we encounter, and (iv) increase our exposure to less creditworthy counterparties.

Lower oil, NGL and natural gas prices or negative adjustments to oil, NGL and natural gas reserves may result in significant impairment charges.

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 development dry holes are capitalized and amortized by property using the unit-of-production method (the ratio of oil, NGL and natural gas volumes produced to total proved or proved developed reserves) as oil, NGL and natural gas are produced.

All long-lived assets, principally the Company's oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset on our books may be greater than its future net cash flows. The need to test a property for impairment may result from declines in oil, NGL and natural gas sales prices or unfavorable adjustments to oil, NGL and natural gas reserves. Also, once assets are classified as held for sale, they are reviewed for impairment. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded. If an impairment charge is recognized, cash flow from operating activities is not impacted, but net income and, consequently, shareholders' equity are reduced. In periods when impairment charges are incurred, it could have a material adverse effect on our results of operations. See Note 1 to the financial statements included in Item 8 – "Financial Statements and Supplemental Data" for further discussion on impairment under the heading "Depreciation, Depletion, Amortization and Impairment."

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil, NGL and natural gas with precision. Oil, NGL and natural gas reserve engineering requires subjective estimates of underground accumulations of oil, NGL and natural gas using assumptions concerning future prices of these commodities, future production levels, and operating and development costs. In estimating our reserves, we and our Independent Consulting Petroleum Engineering Firm must make various assumptions with respect to many matters that may prove to be incorrect, including:

- future oil, NGL and natural gas prices
- production rates
- reservoir pressures, decline rates, drainage areas and reservoir limits
- interpretation of subsurface conditions including geological and geophysical data
- potential for water encroachment or mechanical failures
- levels and timing of capital expenditures, lease operating expenses, production taxes and income taxes, and availability of funds for such expenditures
- effects of government regulation

If any of these assumptions prove to be incorrect, our estimates of reserves, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure of oil and natural gas reserves is calculated using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month individual product prices for each month within the 12-month period prior to September 30. These prices and the operating costs in effect as of the date of estimation are held flat over the life of the properties. From this calculation of future estimated development, production and income tax expenses are deducted with the result discounted at 10% per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates made for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures. Further, our lack of knowledge of all individual well information known to the well operators such as incomplete well stimulation efforts, restricted production rates for various reasons and up-to-date well production data, etc. may cause differences in our reserve estimates.

Because PUD reserves, under SEC reporting rules, may only be recorded if the wells they relate to are scheduled to be drilled within five years of the date of recording, the removal of PUD reserves that are not developed within this five-year period may be required. Removals of this nature may significantly reduce the quantity and present value of the Company's oil, NGL and natural gas reserves. Please read Item 2 – "Properties – Proved Reserves" and Note 11 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data."

Because forward-looking prices and costs are not used to estimate discounted future net cash flows from our estimated proved reserves, the standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil, NGL and natural gas reserves.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net cash flows, in compliance with the FASB statement on oil and natural gas producing activities disclosures, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company, or the oil and natural gas industry in general.

Failure to find or acquire additional reserves will cause reserves and production to decline materially from their current levels.

The rate of production from oil and natural gas properties generally declines as reserves are depleted. The Company's proved reserves will decline materially as reserves are produced except to the extent that the Company acquires additional properties containing proved reserves, conducts additional successful exploration and development drilling, successfully applies new technologies or identifies additional behind-pipe zones (different productive zones within existing producing well bores) or secondary recovery reserves.

Drilling for oil and natural gas invariably involves unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient reserves to return a profit after deducting drilling, completion, operating and other costs. In addition, wells that are profitable may not achieve a targeted rate of return. The Company relies on third-party operators' interpretation of seismic data and other advanced technologies in identifying prospects and in conducting exploration and development activities. Nevertheless, prior to drilling a well, the seismic data and other technologies used do not allow operators to know conclusively whether oil, NGL or natural gas is present in commercial quantities.

Cost factors can adversely affect the economics of any project, and ultimately the cost of drilling, completing and operating a well is controlled by well operators and existing market conditions. Further, drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions
- title problems
- pressure or irregularities in formations
- equipment failures or accidents
- fires, explosions, blowouts and surface cratering
- lack of availability to market production via pipelines or other transportation
- adverse weather conditions
- environmental hazards or liabilities
- lack of water disposal facilities
- governmental regulations
- cost and availability of drilling rigs, equipment and services
- expected sales price to be received for oil, NGL or natural gas produced from the wells

Oil and natural gas drilling and producing operations involve various risks.

The Company is subject to all the risks normally incident to the operation and development of oil and natural gas properties, including:

- well blowouts, cratering, explosions and human related accidents
- mechanical, equipment and pipe failures
- adverse weather conditions, earthquakes and other natural disasters
- civil disturbances and terrorist activities

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- oil, NGL and natural gas price reductions
- environmental risks stemming from the use, production, handling and disposal of water, waste materials, hydrocarbons and other substances into the air, soil or water
- title problems
- limited availability of financing
- marketing related infrastructure, transportation and processing limitations
- regulatory compliance issues

As a non-operator, we are dependent on third-party operators and the contractors they hire for operational safety, environmental safety and compliance with regulations of governmental authorities.

The Company maintains insurance against many potential losses or liabilities arising from well operations in accordance with customary industry practices and in amounts believed by management to be prudent. However, this insurance does not protect the Company against all risks. For example, the Company does not maintain insurance for business interruption, acts of war or terrorism. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant uninsured costs that could have a material adverse effect on the Company’s business condition and financial results.

Debt level and interest rates may adversely affect our business.

The Company has a credit facility with a group of banks headed by Bank of Oklahoma (BOK), which consists of a revolving loan of $200,000,000. As of September 30, 2017, the Company had a balance of $52,222,000 drawn on the facility. The facility has a current borrowing base of $80,000,000, which is secured by certain of the Company’s properties and contains certain restrictive covenants.

Should the Company incur additional indebtedness under its credit facility to fund capital projects or for other reasons, there is risk of it adversely affecting our business operations as follows:

- cash flows from operating activities required to service indebtedness may not be available for other purposes
- covenants contained in the Company’s borrowing agreement may limit our ability to borrow additional funds, pay dividends and make certain investments
- any limitation on the borrowing of additional funds may affect our ability to fund capital projects and may also affect how we will be able to react to economic and industry changes

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- a significant increase in the interest rate on our credit facility will limit funds available for other purposes
- changes in prevailing interest rates may affect the Company's capability to meet its interest payments, as its credit facility bears interest at floating rates

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination and is based in part on oil, NGL and natural gas prices. A lowering of our borrowing base because of lower oil, NGL or natural gas prices, or for other reasons, could require us to repay indebtedness in excess of the newly established borrowing base, or we might need to further secure the debt with additional collateral. Our ability to meet any debt obligations depends on our future performance. General business, economic, financial and product pricing conditions, along with other factors, affect our future performance, and many of these factors are beyond our control. In addition, our failure to comply with the restrictive covenants relating to our credit facility could result in a default, which could adversely affect our business, financial condition, results of operations and cash flows.

The issuance of additional shares of our common stock could cause the market price of our common stock to decline and may result in dilution to our existing shareholders.

The Company has filed a shelf registration statement, which was declared effective on November 15, 2017, that allows us to issue up to $75 million in securities including common stock, preferred stock, debt, warrants and units. The shelf registration statement is intended to provide the Company with increased financial flexibility and more efficient access to the capital markets.

We cannot predict the effect, if any, that market sales of these securities or the availability of the securities will have on the market price of our common stock prevailing from time to time. Substantial sales of shares of our common stock or other securities in the public market, or the perception that those sales could occur, may cause the market price of our common stock to decline. Such a decrease in our share price could in turn impair our ability to raise capital through the sale of additional equity securities. In addition, any such decline may make it more difficult for you to sell shares of our common stock at prices you deem acceptable.

We are currently authorized to issue an aggregate of 24,000,000 shares of common stock of which 16,678,016 shares were issued and outstanding on December 1, 2017. Future issuances of our common stock, or other securities convertible into our common stock, may result in significant dilution to our existing shareholders. Significant dilution would reduce the proportionate ownership and voting power held by our existing shareholders.

Future legislative or regulatory changes may result in increased costs and decreased revenues, cash flows and liquidity.

Companies that operate wells in which Panhandle owns a working interest are subject to extensive federal, state and local regulation. Panhandle, as a working interest owner, is therefore indirectly subject to these same regulations. New or changed laws and regulations such as those described below could have a material adverse effect on our business.

Federal Income Taxation

The United States House of Representatives and the Senate have each passed their own version of tax reform (the “Tax Bill”) which is a proposed overhaul of the Internal Revenue Code of 1986 and could alter tax rates for individuals and businesses and could eliminate several tax deductions, including several deductions utilized by the Company. The house and the senate bills still have to be reconciled and we do not know if the Tax Bill will be adopted in whole, in part or not at all. As a result, the impact of the Tax Bill on us is uncertain at this time.

Proposals to repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses, if enacted, would increase and accelerate the Company’s payment of federal income taxes. As a result, these changes would decrease the Company’s cash flows available for developing its oil and natural gas properties.

Hydraulic Fracturing and Water Disposal

The vast majority of oil and natural gas wells drilled in recent years have been, and future wells are expected to be, hydraulically fractured as a part of the process of completing the wells and putting them on production. This is true of the wells drilled in which the Company owns an interest. Hydraulic fracturing is a process that involves pumping water, sand and additives at high pressure into rock formations to stimulate oil and natural gas production. In developing plays where hydraulic fracturing, which requires large volumes of water, is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

In addition to water, hydraulic fracturing fluid contains chemical additives designed to optimize production. Well operators are being required in certain states to disclose the components of these additives. Additional states and the federal government may follow with similar requirements or may restrict the use of certain additives. This could result in more costly or less effective development of wells.

Once a well has been hydraulically fractured, the fluid produced from the fractured wells must be either treated for reuse or disposed of by injecting the fluid into disposal wells. Injection well disposal processes have been, and continue to be, studied to determine the extent of correlation between injection well disposal and the occurrence of earthquakes. Certain studies have concluded there is a correlation, and this has resulted in the cessation of or the reduction of injection rates in certain water disposal wells, especially in northern Oklahoma.

Efforts to regulate hydraulic fracturing and fluid disposal continue at the local, state and federal level. New regulations are being considered, including limiting water withdrawals and usage, limiting water disposition, restricting which additives may be used, implementing state-wide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive areas. Public sentiment against hydraulic fracturing and fluid disposal and shale production could result in more stringent permitting and compliance requirements. Consequences of these actions could potentially increase capital, compliance and operating costs significantly, as well as delay or halt the further development of oil and gas reserves on the Company's properties.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows.

Climate Change

Certain studies have suggested that emission of certain gases, commonly referred to as "greenhouse gases," may be impacting the earth's climate. Methane, the primary component of natural gas, and carbon dioxide, a by-product of burning oil and natural gas, are examples of greenhouse gases. Various state governments and regional organizations are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as oil and gas production equipment and operations.

In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, in preparing an agreement which set greenhouse gas emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016. To help achieve these reductions, federal agencies addressed climate change through a variety of administrative actions. The U.S. Environmental Protection Agency (the "EPA") issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. However, on June 1, 2017, President Trump announced that the United States will withdraw and attempt to negotiate a different agreement.

The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions from the oil and natural gas industry. Even if federal efforts in this area slow, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require our operators to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand.

Seismic Activity

Recent earthquakes in northern and central Oklahoma and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation that could lead to operational delays, increase operating and compliance costs or otherwise adversely affect operations.

Shortages of oilfield equipment, services, qualified personnel and resulting cost increases could adversely affect results of operations.

The demand for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, resulting in periodic shortages. When demand for rigs and equipment increases due to an increase in the number of wells being drilled, there have been shortages of drilling rigs, hydraulic fracturing equipment and personnel and other oilfield equipment. Higher oil, NGL and natural gas prices generally stimulate increased demand for, and result in increased prices of, drilling rigs, crews and associated supplies, equipment and services. These shortages or price increases could negatively affect the ability to drill wells and conduct ordinary operations by the operators of the Company's wells, resulting in an adverse effect on the Company's financial condition, cash flow and operating results.

Competition in the oil and natural gas industry is intense, and most of our competitors have greater financial and other resources than we do.

We compete in the highly competitive areas of oil and natural gas acquisition, development, exploration and production. We face intense competition from both major and independent oil and natural gas companies to acquire desirable producing properties, new properties for future exploration and human resource expertise necessary to effectively develop properties. We also face similar competition in obtaining sufficient capital to maintain drilling rights in all drilling units.

A substantial number of our competitors have financial and other resources significantly greater than ours, and some of them are fully integrated oil and natural gas companies. These companies are able to pay more for development prospects and productive oil and natural gas properties and are able to define, evaluate, bid for, purchase and subsequently drill a greater number of properties and prospects than our financial or human resources permit, potentially reducing our ability to participate in drilling on certain of our acreage as a working interest owner. Our ability to develop and exploit our oil and natural gas properties and to acquire additional quality properties in the future will depend upon our ability to successfully evaluate, select and acquire suitable properties and join in drilling with reputable operators in this highly competitive environment.

Significant capital expenditures are required to replace our reserves and conduct our business.

The Company funds exploration, development and production activities primarily through cash flows from operations and acquisitions through borrowings under its credit facility. The timing and amount of capital necessary to carry out these activities can vary significantly as a result of product price fluctuations, property acquisitions, drilling results and the availability of drilling rigs, equipment, well services and transportation capacity.

Cash flows from operations and access to capital are subject to a number of variables, including the Company's:

- amount of proved reserves
- volume of oil, NGL and natural gas produced
- received prices for oil, NGL and natural gas sold
- ability to acquire and produce new reserves
- ability to obtain financing

We may have limited ability to obtain the capital required to sustain our operations at current levels if our borrowing base under our credit facility is lowered as a result of decreased revenues, lower product prices, declines in reserves or for other reasons. Failure to sustain operations at current levels could have a material adverse effect on our financial condition, cash flow and results of operations.

We may be subject to information technology system failures, network disruptions, cyber-attacks or other breaches in data security.

Power, telecommunication or other system failures due to hardware or software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, human error or by other means could significantly affect the Company's ability to conduct its business. Though we have implemented complex network security measures, stringent internal controls and maintain offsite backup of all crucial electronic data, there cannot be absolute assurance that a form of system failure or data security breach will not have a material adverse effect on our financial condition and operations results.

ITEM 1B UNRESOLVED STAFF COMMENTS

None

ITEM 2 PROPERTIES

At September 30, 2017, Panhandle's principal properties consisted of (1) perpetual ownership of 255,039 net mineral acres, held principally in Arkansas, New Mexico, North Dakota, Oklahoma, Texas and six other states; (2) leases on 19,351 net acres primarily in Oklahoma: and (3) working interests, royalty interests, or both, in 6,095 producing oil and natural gas wells and 63 wells in the process of being drilled or completed.

Consistent with industry practice, the Company does not have current abstracts or title opinions on all of its mineral acreage and, therefore, cannot be certain that it has unencumbered title to all of these properties. In recent years, a few insignificant challenges have been made against the Company's fee title to its acreage.

The Company pays ad valorem taxes on minerals owned in nine states.

ACREAGE

Mineral Interests Owned

The following table of mineral acreage owned reflects, in each respective state, the number of net and gross acres, net and gross producing acres, net and gross acres leased, and net and gross acres open (unleased) as of September 30, 2017.

State	Net Acres	Gross Acres	Net Acres Producing (1)	Gross Acres Producing (1)	Net Acres Leased to Others (2)	Gross Acres Leased to Others (2)	Net Acres Open (3)	Gross Acres Open (3)
Arkansas	11,963	51,641	7,166	27,026	-	-	4,796	24,615
Colorado	8,217	39,080	-	-	8	80	8,209	39,000
Florida	3,832	8,212	-	-	-	-	3,832	8,212
Kansas	3,082	11,816	144	1,200	-	-	2,938	10,616
Montana	1,008	17,947	-	-	-	-	1,008	17,947
New Mexico	57,374	174,300	1,366	6,965	175	360	55,833	166,975
North Dakota	11,179	64,286	190	2,196	-	-	10,989	62,090
Oklahoma	113,490	953,314	42,495	338,387	7,213	47,595	63,782	567,332
South Dakota	1,825	9,300	-	-	-	-	1,825	9,300
Texas	43,043	362,274	5,502	55,621	7,684	58,203	29,856	248,450
Other	27	262	-	-	-	-	27	262
Total:	255,039	1,692,433	56,864	431,395	15,080	106,238	183,096	1,154,800

(1) "Producing" represents the mineral acres in which Panhandle owns a royalty or working interest in a producing well.
(2) "Leased" represents the mineral acres owned by Panhandle that are leased to third parties but not producing.
(3) "Open" represents mineral acres owned by Panhandle that are not leased or in production.

Leases

The following table reflects net mineral acres leased from others, lease expiration dates, and net leased acres held by production as of September 30, 2017.

State	Net Acres	Net Acres Expiring					Net Acres Held by Production
		2018	2019	2020	2021	2022	
Arkansas	2,159	88	-	-	-	-	2,071
Kansas	2,117	-	-	-	-	-	2,117

Oklahoma	11,641	-	-	-	-	-	11,641
Texas	2,352	-	-	-	-	-	2,352
Other	1,083	-	-	-	-	-	1,083
TOTAL	19,351	88	-	-	-	-	19,263

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PROVED RESERVES

The following table summarizes estimates of proved reserves of oil, NGL and natural gas held by Panhandle as of September 30, 2017, compared to the two preceding year ends. Proved reserves are located onshore within the contiguous United States and are principally made up of small interests in 6,095 wells, which are predominately located in the Mid-Continent region. Other than this report, the Company's reserve estimates are not filed with any other federal agency.

	Barrels of Oil	Barrels of NGL	Mcf of Natural Gas	Mcfe
Net Proved Developed Reserves				
September 30, 2017	2,201,528	1,768,425	87,861,043	111,680,761
September 30, 2016	1,980,519	1,095,256	62,929,047	81,383,697
September 30, 2015	2,725,077	1,466,834	82,899,159	108,050,625
Net Proved Undeveloped Reserves				
September 30, 2017	3,308,139	616,274	33,334,077	56,880,555
September 30, 2016	3,445,571	527,447	18,796,551	42,634,659
September 30, 2015	4,313,353	1,453,766	37,314,885	71,917,599
Net Total Proved Reserves				
September 30, 2017	5,509,667	2,384,699	121,195,120	168,561,316
September 30, 2016	5,426,090	1,622,703	81,725,598	124,018,356
September 30, 2015	7,038,430	2,920,600	120,214,044	179,968,224

The 44.5 Bcfe increase in total proved reserves from 2016 to 2017 is primarily a combination of the following factors:

- Positive pricing revisions of 17.9 Bcfe, primarily due to wells reaching their projected economic limits much later than projected in 2016: proved developed revisions of 17.3 Bcfe and PUD revisions of 0.6 Bcfe.
- Negative performance revisions of 0.3 Bcfe.
- Proved developed reserve extensions, discoveries and other additions of 9.9 Bcfe principally resulting from the Company's participation in six wells in the liquids-rich portion of the Anadarko Woodford Shale in Canadian County, Oklahoma.
- The addition of 29.1 Bcfe of PUD reserves, all are within the Company's active drilling program areas of the Anadarko Woodford Shale (Cana, STACK and SCOOP) and southeastern Oklahoma Woodford.
- The sale of 1.0 Bcfe in marginal properties located in southwestern Oklahoma.
- Production of 11.1 Bcfe.

The following details the changes in proved undeveloped reserves for 2017 (Mcfe):

Beginning proved undeveloped reserves	42,634,659
Proved undeveloped reserves transferred to proved developed	(15,670,848)
Revisions	819,338
Extensions and discoveries	29,097,406
Purchases	-
Ending proved undeveloped reserves	56,880,555

Beginning PUD reserves were 42.6 Bcfe. A total of 15.7 Bcfe (37% of the beginning balance) was transferred to proved developed producing during 2017. The 0.8 Bcfe (2% of the beginning balance) of positive revisions to PUD reserves were pricing revisions of 0.6 Bcfe and performance revision of 0.2 Bcfe. No PUD locations from 2013 remain in the PUD category. We anticipate that all the Company's PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves, which are no longer projected to be drilled within five years from the date they were added to PUD reserves, will be removed as revisions at the time that determination is made. In the event that there are undrilled PUD locations at the end of the five-year period, it is our intent to remove the reserves associated with those locations from our proved reserves as revisions. The Company added 29.1 Bcfe of PUD reserves in 2017 within the Company's active drilling program areas of the Anadarko Woodford Shale (Cana, STACK, SCOOP) and southeastern Oklahoma Woodford Shale.

The determination of reserve estimates is a function of testing and evaluating the production and development of oil and natural gas reservoirs in order to establish a production decline curve. The established production decline curves, in conjunction with oil and natural gas prices, development costs, production taxes and operating expenses, are used to estimate oil and natural gas reserve quantities and associated future net cash flows. As information is processed regarding the development of individual reservoirs, and as market conditions change, estimated reserve quantities and future net cash flows will change over time as well. Estimated reserve quantities and future net cash flows are affected by changes in product prices. These prices have varied substantially in recent years and are expected to vary substantially from current pricing in the future.

The Company follows the SEC's modernized oil and natural gas reporting rules, which were effective for annual reports on Form 10–K for fiscal years ending on or after December 31, 2009. See Note 11 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" for disclosures regarding our oil and natural gas reserves.

Proved oil and natural gas reserves are those quantities of 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 that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves, which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection), are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserve estimate, if the extraction is by means not involving a well.

Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, calculated the Company's oil, NGL and natural gas reserves as of September 30, 2017, 2016 and 2015 (see Exhibits 23 and 99).

The Company's net proved oil, NGL and natural gas reserves (including certain undeveloped reserves described above) are located onshore in the contiguous United States. All studies have been prepared in accordance with regulations prescribed by the SEC. The reserve estimates were based on economic and operating conditions existing at September 30, 2017, 2016 and 2015. Since the determination and valuation of proved reserves is a function of testing and estimation, the reserves presented should be expected to change as future information becomes available.

ESTIMATED FUTURE NET CASH FLOWS

Set forth below are estimated future net cash flows with respect to Panhandle's net proved reserves (based on the estimated units set forth above in Proved Reserves) for the year indicated, and the present value of such estimated future net cash flows, computed by applying a 10% discount factor as required by SEC rules and regulations. The Company follows the SEC rule, Modernization of Oil and Gas Reporting Requirements. In accordance with the SEC rule, the estimated future net cash flows were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month individual product prices for each month within the 12-month period prior to September 30 held flat over the life of the properties and applied to future production of proved reserves less estimated future development and production expenditures for these reserves. The amounts presented are net of operating costs and production taxes levied by the respective states. Prices used for determining future cash flows from oil, NGL and natural gas as of September 30, 2017, 2016 and 2015, were as follows: $46.31/Bbl, $17.55/Bbl, $2.81/Mcf; $36.77/Bbl, $12.22/Bbl, $1.97/Mcf; $55.27/Bbl, $19.10/Bbl, $2.84/Mcf, respectively. These future net cash flows based on SEC pricing rules should not be construed as the fair market value of the Company's reserves. A market value determination would need to include many additional factors, including anticipated oil, NGL and natural gas price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9/30/2017	9/30/2016	9/30/2015
Proved Developed	$206,878,778	$98,380,962	$233,189,810
Proved Undeveloped	81,303,463	26,502,846	116,314,237
Income Tax Expense	(102,193,819)	(38,674,100)	(123,007,909)
Total Proved	$185,988,422	$86,209,708	$226,496,138

10% Discounted Present Value of Estimated Future Net Cash Flows

	9/30/2017	9/30/2016	9/30/2015
Proved Developed	$112,276,166	$55,586,606	$126,295,752
Proved Undeveloped	13,746,585	(7,696,741)	17,948,482
Income Tax Expense	(45,190,176)	(18,119,746)	(62,653,023)
Total Proved	$80,832,575	$29,770,119	$81,591,211

OIL, NGL AND NATURAL GAS PRODUCTION

The following table sets forth the Company's net production of oil, NGL and natural gas for the fiscal periods indicated.

	Year Ended 9/30/2017	Year Ended 9/30/2016	Year Ended 9/30/2015
Bbls - Oil	310,677	364,252	453,125
Bbls - NGL	173,858	171,060	210,960
Mcf - Natural Gas	8,194,529	8,284,377	9,745,223
Mcfe	11,101,739	11,496,249	13,729,733

AVERAGE SALES PRICES AND PRODUCTION COSTS

The following tables set forth unit price and cost data for the fiscal periods indicated.

Average Sales Price	Year Ended 9/30/2017	Year Ended 9/30/2016	Year Ended 9/30/2015
Per Bbl, Oil	$ 46.27	$ 36.70	$ 53.12
Per Bbl, NGL	$ 19.87	$ 12.60	$ 18.25
Per Mcf, Natural Gas	$ 2.70	$ 1.92	$ 2.73
Per Mcfe	$ 3.60	$ 2.73	$ 3.97

Average Production (lifting) Costs	Year Ended 9/30/2017	Year Ended 9/30/2016	Year Ended 9/30/2015
(Per Mcfe)			
Well Operating Costs (1)	$ 1.14	$ 1.18	$ 1.27
Production Taxes (2)	0.14	0.09	0.12
	$ 1.28	$ 1.27	$ 1.39

(1) Includes actual well operating costs, compression, handling and marketing fees paid on natural gas sales and other minor expenses associated with well operations.
(2) Includes production taxes only.

In fiscal 2017, approximately 25% of the Company's oil, NGL and natural gas revenue was generated from royalty payments received on its mineral acreage. Royalty interests bear no share of the operating costs on those producing wells.

GROSS AND NET PRODUCTIVE WELLS AND DEVELOPED ACRES

The following table sets forth Panhandle's gross and net productive oil and natural gas wells as of September 30, 2017. Panhandle owns either working interests, royalty interests or both in these wells. The Company does not operate any wells.

	Gross Working Interest Wells	Net Working Interest Wells	Gross Royalty Only Wells	Total Gross Wells
Oil	337	26.87	1,142	1,479
Natural Gas	1,717	78.62	2,899	4,616
Total	2,054	105.49	4,041	6,095

Panhandle's average interest in royalty interest only wells is 0.80%. Panhandle's average interest in working interest wells is 5.14% working interest and 4.91% net revenue interest.

Information on multiple completions is not available from Panhandle's records, but the number is not believed to be significant. With regard to Gross Royalty Only Wells, some of these wells are in multi-well unitized fields. In such cases, the Company's ownership in each unitized field is counted as one gross well as the Company does not have access to the actual well count in all of these unitized fields.

As of September 30, 2017, Panhandle owned 431,395 gross developed mineral acres and 56,864 net developed mineral acres. Panhandle has also leased from others 145,828 gross developed acres containing 19,263 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2017, Panhandle owned 1,261,038 gross and 198,176 net undeveloped mineral acres, and leases on 640 gross and 88 net undeveloped acres.

DRILLING ACTIVITY

The following net productive development, exploratory and purchased wells and net dry development, exploratory and purchased wells in which the Company had either a working interest, a royalty interest or both were drilled and completed during the fiscal years indicated.

	Net Productive Working Interest Wells	Net Productive Royalty Interest Wells	Net Dry Working Interest Wells
Development Wells			
Fiscal years ended:			
September 30, 2017	3.893043	0.456612	-
September 30, 2016	0.541405	0.475375	-
September 30, 2015	5.349843	1.372020	-
Exploratory Wells			
Fiscal years ended:			
September 30, 2017	0.001563	-	-
September 30, 2016	0.002732	0.003186	-
September 30, 2015	0.188489	0.060184	-
Purchased Wells			
Fiscal years ended:			
September 30, 2017	-	-	-
September 30, 2016	-	-	-
September 30, 2015	-	-	-

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and natural gas wells drilling or testing as of September 30, 2017, in which Panhandle owns either a working interest, a royalty interest or both. These wells were not producing at September 30, 2017.

	Gross Working Interest Wells	Net Working Interest Wells	Gross Royalty Only Wells	Total Gross Wells
Oil	6	0.36	34	40
Natural Gas	10	0.06	13	23

OTHER FACILITIES

The Company has a lease on 12,369 square feet of office space in Oklahoma City, Oklahoma, which ends April 30, 2020.

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SAFE HARBOR STATEMENT

This report, including information included in, or incorporated by reference from, future filings by the Company with the SEC, as well as information contained in written material, press releases and oral statements, contains, or may contain, certain statements that are “forward-looking statements,” within the meaning of the federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which are expected to, or anticipated will, or may, occur in the future, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts” and s expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as: the amount and nature of our future capital expenditures; wells to be drilled or reworked; prices for oil, NGL and natural gas; demand for oil, NGL and natural gas; estimates of proved oil, NGL and natural gas reserves; development and infill drilling potential; drilling prospects; business strategy; production of oil, NGL and natural gas reserves; and expansion and growth of our business and operations.

These statements are based on certain assumptions and analyses made by the Company in light of experience and perception of historical trends, current conditions and expected future developments as well as other factors believed appropriate in the circumstances. However, whether actual results and development will conform to our expectations and predictions is subject to a number of risks and uncertainties, which could cause actual results to differ materially from our expectations.

One should not place undue reliance on any of these forward-looking statements. The Company does not currently intend to update forward-looking information and to release publicly the results of any future revisions made to forward-looking statements to reflect events or circumstances, which reflect the occurrence of unanticipated events, after the date of this report.

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made, the following discussion outlines certain factors that in the future could cause results for 2018 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of the Company.

Commodity Prices. The prices received for oil, NGL and natural gas production have a direct impact on the Company’s revenues, profitability and cash flows, as well as the ability to meet its projected financial and operational goals. The prices for crude oil, NGL and natural gas are dependent on a number of factors beyond the Company’s control, including: the supply and demand for oil, NGL and natural gas; weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas); and the ability of current distribution systems in the United States to effectively meet the demand for oil, NGL and natural gas at any given time, particularly in times of peak demand, which may result because of adverse weather conditions.

Oil prices are sensitive to foreign influences based on political, social or economic factors, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of both natural gas and oil are becoming more and more influenced by trading on the commodities markets, which has, at times, increased the volatility associated with these prices.

Uncertainty of Oil, NGL and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond the Company's control. The oil, NGL and natural gas reserve data included in this report represents only an estimate of these reserves. Oil and natural gas reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGL and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas and assumptions concerning future oil, NGL and natural gas prices, future operating costs, severance and excise taxes, development costs, and workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGL and natural gas and estimates of the future net cash flows from oil, NGL and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil, NGL and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to oil, NGL and natural gas reserves will vary from estimates, and those variances can be material.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over operations for these properties or their associated costs. Dependence on the operator and other working interest owners for these projects and the limited ability to influence operations and associated costs could materially and adversely affect the realization of targeted returns on capital in drilling or acquisition activities and targeted production growth rates.

Information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil, NGL and natural gas reserves attributable to the Company's properties. As required by the SEC, the estimated discounted future net cash flows from proved oil, NGL and natural gas reserves are determined based on the fiscal year's 12-month average of the first-day-of-the-month individual product prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the amount and timing of oil, NGL and natural gas production, supply and demand for oil, NGL and natural gas and increases or decreases in consumption.

In addition, the 10% discount factor required by the SEC used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with operations of the oil and natural gas industry in general.

ITEM 3 LEGAL PROCEEDINGS

There were no material legal proceedings involving Panhandle on September 30, 2017, or at the date of this report.

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5 MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The above graph compares the 5-year cumulative total return provided shareholders on our Class A Common Stock (“Common Stock”) relative to the cumulative total returns of the S&P Smallcap 600 Index and the S&P Oil & Gas Exploration & Production Index. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our Common Stock and in each of the indexes on September 30, 2012, and its relative performance is tracked through September 30, 2017.

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Since July 2008, the Company's Common Stock has been listed and traded on the New York Stock Exchange (symbol PHX). The following table sets forth the high and low trade prices of the Common Stock during the periods indicated:

Quarter Ended	High	Low
December 31, 2015	$20.20	$13.18
March 31, 2016	$18.89	$10.82
June 30, 2016	$19.47	$15.34
September 30, 2016	$19.30	$15.45
December 31, 2016	$27.70	$17.10
March 31, 2017	$24.05	$17.55
June 30, 2017	$24.06	$18.15
September 30, 2017	$25.30	$19.20

At December 1, 2017, there were 1,289 holders of record of Panhandle's Class A Common Stock and approximately 5,100 beneficial owners.

During the past two years, the Company has paid quarterly dividends of $0.04 per share on its Common Stock. Approval by the Company's Board is required before the declaration and payment of any dividends.

While the Company anticipates it will continue to pay dividends on its Common Stock, the payment and amount of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and any other factors considered relevant by the Board.

The Company's credit facility also contains a provision limiting the paying or declaring of a cash dividend during any fiscal year to 20% of net cash flow provided by operating activities from the Statement of Cash Flows of the preceding 12-month period. See Note 4 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" for a further discussion of the credit facility.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents information about repurchases of our common stock during the quarter ended September 30, 2017:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program
7/1 - 7/31/17	-	$ -	-	$ 594,533
8/1 - 8/31/17	-	$ -	-	$ 594,533
9/1 - 9/30/17	8,623	$ 22.52	8,623	$ 400,357
Total	8,623	$ 22.52	8,623	

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan in March 2010, the Board directed the purchase of the Company's Common Stock, from time to time, equal to the aggregate number of shares of Common Stock awarded pursuant to the Company's 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. Effective May 2014, the board of directors approved for management to make these purchases of the Company's Common Stock at their discretion. The Board's approval included an initial authorization to purchase up to $1.5 million of Common Stock, with a provision for subsequent authorizations without specific action by the Board. As the amount of Common Stock purchased under any authorization reaches $1.5 million, another $1.5 million is automatically authorized for Common Stock purchases unless the Board determines otherwise.

ITEM 6 SELECTED FINANCIAL DATA

The following table summarizes financial data of the Company for its last five fiscal years and should be read in conjunction with Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 – "Financial Statements and Supplementary Data," including the Notes thereto, included elsewhere in this report.

	As of and for the year ended September 30,				
	2017	2016	2015	2014	2013
Revenues					
Oil, NGL and natural gas sales	$39,935,912	$31,411,353	$54,533,914	$82,846,528	$60,605,878
Lease bonuses and rentals	5,149,297	7,735,785	2,010,395	423,328	938,846
Gains (losses) on derivative contracts	1,249,840	(86,355)	13,822,506	247,414	611,024
	46,335,049	39,060,783	70,366,815	83,517,270	62,155,748
Costs and expenses					
Lease operating expense	12,682,969	13,590,089	17,472,408	13,912,792	11,861,403
Production taxes	1,548,399	1,071,632	1,702,302	2,694,118	1,834,840
Depreciation, depletion and amortization	18,397,548	24,487,565	23,821,139	21,896,902	21,945,768
Provision for impairment	662,990	12,001,271	5,009,191	1,096,076	530,670
Loss (gain) on asset sales & other	105,830	(2,576,237)	(685,369)	(799,559)	(1,666,536)
Interest expense	1,275,138	1,344,619	1,550,483	462,296	157,558
General and administrative	7,441,242	7,139,728	7,339,320	7,433,183	6,801,996
	42,114,116	57,058,667	56,209,474	46,695,808	41,465,699
Income (loss) before provision (benefit) for income taxes	4,220,933	(17,997,884)	14,157,341	36,821,462	20,690,049
Provision (benefit) for income taxes	689,000	(7,711,000)	4,836,000	11,820,000	6,730,000
Net income (loss)	$3,531,933	$(10,286,884)	$9,321,341	$25,001,462	$13,960,049
Basic and diluted earnings (loss) per share	$0.21	$(0.61)	$0.56	$1.49	$0.84
Dividends declared per share	$0.16	$0.16	$0.16	$0.16	$0.14
Weighted average shares outstanding					
Basic and diluted	16,900,185	16,840,856	16,768,904	16,727,183	16,713,808
Net cash provided by (used in):					
Operating activities	$20,758,192	$22,639,151	$47,624,914	$53,099,746	$38,425,477
Investing activities	$(25,107,760)	$565,617	$(31,642,385)	$(122,428,139)	$(27,403,043)
Financing activities	$4,436,146	$(23,337,470)	$(15,888,369)	$66,970,977	$(10,139,362)
Total assets	$206,744,219	$197,824,326	$238,825,273	$246,640,604	$147,838,430
Long-term debt	$52,222,000	$44,500,000	$65,000,000	$78,000,000	$8,262,256
Shareholders' equity	$116,707,539	$115,191,819	$127,004,675	$119,188,653	$95,655,486

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

BUSINESS OVERVIEW

The Company's principal line of business is to explore for, develop, acquire, produce and sell oil, NGL and natural gas. Results of operations are dependent primarily upon the Company's: existing reserve quantities; costs associated with acquiring, exploring for and developing new reserves; production quantities and related production costs; and oil, NGL and natural gas sales prices.

Fiscal 2017 oil and natural gas production decreased 15% and 1%, respectively, and NGL production increased 2% from that of 2016. The 2017 higher oil, NGL and natural gas prices (see below), partially offset by overall production changes noted above, resulted in a 27% increase in revenues from the sale of oil, NGL and natural gas. Based on recent forward strip pricing, the Company currently anticipates 2018 average oil, NGL and natural gas prices will be slightly higher than their corresponding average prices in 2017.

The Company's proved developed oil, NGL and natural gas reserves increased in 2017, compared to 2016, by 30.3 Bcfe, or 37%. The increase was primarily due to positive pricing revisions, conversion from PUD, additions and extensions.

As of September 30, 2017, the Company owned an average 1.2% net revenue interest in 63 wells that were drilling or testing.

Other than the lease of office space, the Company had no off balance sheet arrangements during 2017 or prior years.

The following table reflects certain operating data for the periods presented:

	For the Year Ended September 30,				
	2017	Percent Incr. or (Decr.)	2016	Percent Incr. or (Decr.)	2015
Production:					
Oil (Bbls)	310,677	(15%)	364,252	(20%)	453,125
NGL (Bbls)	173,858	2%	171,060	(19%)	210,960
Natural Gas (Mcf)	8,194,529	(1%)	8,284,377	(15%)	9,745,223
Mcfe	11,101,739	(3%)	11,496,249	(16%)	13,729,733
Average Sales Price:					
Oil (per Bbl)	$46.27	26%	$36.70	(31%)	$53.12
NGL (per Bbl)	$19.87	58%	$12.60	(31%)	$18.25
Natural Gas (per Mcf)	$2.70	41%	$1.92	(30%)	$2.73
Mcfe	$3.60	32%	$2.73	(31%)	$3.97

RESULTS OF OPERATIONS

Fiscal Year 2017 Compared to Fiscal Year 2016

Overview

The Company recorded net income of $3,531,933, or $0.21 per share, in 2017, compared to net loss of $10,286,884, or $0.61 per share, in 2016. Revenues increased in 2017 primarily due to higher oil, NGL and natural gas sales and increased gains on derivative contracts partially offset by decreased lease bonuses received.

Expenses decreased in 2017 mainly from a lower provision for impairment, lower DD&A and lower LOE partially offset by increases in G&A and production taxes and a decrease in gain on sale of assets.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales increased $8,524,559, or 27%, for 2017, as compared to 2016. The increase was due to increased oil, NGL and natural gas prices of 26%, 58% and 41%, respectively, partially offset with lower oil and natural gas volumes of 15% and 1%, respectively, in 2017.

In the first half of 2017, we continued to see the results of expected production decline in oil, NGL and natural gas volumes. The results of our 2017 drilling program are reflected in the third and fourth quarters as first sales of the new wells began to occur.

The decrease in oil production was primarily the result of natural production decline in the Eagle Ford Shale, which was partially offset by 2017 drilling with first sales from two wells in late April and four wells in mid-August. To a lesser extent, declining production from various fields in western Oklahoma, the Texas Panhandle, and Bakken contributed to the decrease.

An overall increase in NGL production is the result of six new wells in the Anadarko Woodford Shale and six wells in the Eagle Ford Shale, which offset the natural production decline of existing wells in the Anadarko Woodford Shale in western and central Oklahoma and the Anadarko Basin Granite Wash in western Oklahoma and the Texas Panhandle.

Natural gas production volume decreases were primarily the result of naturally declining production in the Fayetteville Shale. To a much lesser extent, declining production from the Anadarko Woodford Shale in western and central Oklahoma, the Anadarko Basin Granite Wash and the southeastern Oklahoma Woodford Shale also contributed to the decrease. The decline was offset as a result of new well drilling in southeastern Oklahoma Woodford Shale, with first sales from four new wells in early March and four more wells in mid-May. Additional contribution to gas production was established in the Anadarko Woodford Shale from six new wells with first sales in mid-July.

Production by quarter for 2017 and 2016 was as follows (Mcfe):

	2017	2016
First quarter	2,517,414	3,143,400
Second quarter	2,351,207	2,786,303
Third quarter	2,953,915	2,887,821
Fourth quarter	3,279,203	2,678,725
Total	11,101,739	11,496,249

Lease Bonus and Rentals

Lease bonuses and rentals decreased $2,586,488 in 2017. The decrease was mainly due to the Company leasing fewer acres in 2017 versus 2016. In 2017, the Company leased 2,067 net mineral acres in Oklahoma (mainly in Dewey, Canadian, McClain and Grady Counties), 272 net mineral acres in Texas (mainly in Andrews and Dawson Counties) and 125 net mineral acres in New Mexico (mainly in Lea and Eddy Counties). In 2016, the Company leased 4,057 net mineral acres in Cochran County, Texas, 663 net mineral acres in Blaine, Canadian, Custer and Dewey Counties, Oklahoma, and 706 net mineral acres in Grady and McClain Counties, Oklahoma.

Gains (Losses) on Derivative Contracts

The fair value of derivative contracts was a net asset of $516,159 as of September 30, 2017, and a net liability of $428,271 as of September 30, 2016. We had a net gain on derivative contracts of $1,249,840 in 2017 as compared to a net loss of $86,355 in 2016. The change is principally due to the oil and natural gas collars and fixed price swaps being more beneficial in the 2017, as NYMEX oil and natural gas futures experienced decreases in price in relation to the collars and the fixed prices of the swaps. As of September 30, 2017, the Company's natural gas and oil costless collar contracts and fixed price swaps have expiration dates of December 2017 through December 2018.

Lease Operating Expenses (LOE)

LOE decreased $907,120 or 7% in 2017. LOE costs per Mcfe of production decreased from $1.18 in 2016 to $1.14 in 2017. The total LOE decrease was largely due to decreased field operating costs of $1,561,965 in 2017, compared to 2016. Field operating costs were $0.58 per Mcfe in 2017, compared to $0.70 per Mcfe in 2016, a 17% decrease. This decrease in rate was principally the result of significant new low-cost production coming on, decreased operating costs in several fields and the company selling some high operating cost wells in 2017.

The decrease in LOE related to field operating costs was partially offset with an increase in handling fees (primarily gathering, transportation and marketing costs) of $654,845 in 2017, as compared to 2016. On a per Mcfe basis, these fees increased $0.08 due mainly to a 15% decrease in oil production versus a 1% decrease in natural gas production. Natural gas sales bear the large majority of the handling fees. Handling fees are charged either as a percent of sales or based on production volumes.

Production Taxes

Production taxes increased $476,767 or 44% in 2017, as compared to 2016. The increase in amount was primarily the result of increased oil, NGL and natural gas sales of $8,524,559 during 2017. Production taxes as a percentage of oil, NGL and natural gas sales increased from 3.4% in 2016 to 3.9% in 2017. The increase in tax rate was the result of the expiration of production tax discounts on some of the Company's horizontally drilled wells in Oklahoma and Arkansas. The low overall production tax rate in both years was due to a large proportion of the Company's oil and natural gas revenues coming from horizontally drilled wells, which are eligible for reduced Oklahoma and Arkansas production tax rates in the first few years of production.

Depreciation, Depletion and Amortization (DD&A)

DD&A decreased $6,090,017 in 2017. DD&A per Mcfe was $1.66 in 2017, compared to $2.13 in 2016. DD&A decreased $5,249,692 as the result of a $0.47 decrease in the DD&A rate per Mcfe. This was coupled by a decrease of $840,325 due to oil, NGL and natural gas production volumes decreasing 3% collectively in 2017, compared to 2016. The rate decrease was principally due to higher oil, NGL and natural gas prices utilized in the reserve calculations during 2017, as compared to 2016, lengthening the economic life of wells thus resulting in higher projected remaining reserves on a significant number of wells. The Company had new high volume wells with low finding costs begin producing in the 2017, which also contributed to the rate decrease.

Provision for Impairment

Provision for impairment decreased $11,338,281 in 2017, as compared to 2016. During 2017, impairment of $46,279 was recorded on five fields, primarily in Oklahoma and Texas. Another $616,711 of impairment was recorded on a group of wells that were held for sale at September 30, 2017. During 2016, impairment of $12,001,271 was recorded on 44 fields, primarily in Oklahoma, Kansas and Texas. Two fields in western Oklahoma and the Texas Panhandle accounted for $7,548,533 or 63% of the impairment due mainly to declining oil, NGL and natural gas prices.

Loss (Gain) on Asset Sales and Other

Loss (gain) on asset sales and other was a net loss of $105,830 in 2017, as compared to a net gain of $2,576,237 in 2016. The net loss in 2017 was mainly due to the Company selling some high operating cost wells at a loss during the year. The net gain in 2016 was largely due to the gain on sale of assets from two of the Company's partnerships.

Interest Expense

Interest expense decreased $69,481 in 2017, as compared to 2016. The decrease was due to a lower outstanding debt balance during 2017.

General and Administrative Costs (G&A)

G&A increased $301,514 in 2017, as compared to 2016. This increase was primarily the result of higher legal and technical consulting fees in 2017. The legal fee increase was mainly due to additional work done around the Company filing its first shelf registration. The technical consulting fee increase was due to additional work performed to analyze possible acquisitions.

Provision (Benefit) for Income Taxes

The 2017 provision for income taxes of $689,000 was based on a pre-tax income of $4,220,933, as compared to a benefit for income taxes of $7,711,000 in 2016, based on a pre-tax loss of $17,997,884. The effective tax rate for 2017 and 2016 was a 16% provision and a 43% benefit, 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 in 2016. The effective tax rate for 2017 was also impacted by excess tax benefits from stock-based compensation recorded to income tax expense (benefit) during 2017.

Fiscal Year 2016 Compared to Fiscal Year 2015

Overview

The Company recorded net loss of $10,286,884, or $0.61 per share, in 2016, compared to net income of $9,321,341, or $0.56 per share, in 2015. Revenues decreased in 2016 primarily due to lower oil, NGL and natural gas sales and decreased gains on derivative contracts partially offset by increased lease bonuses received.

Expenses increased in 2016, mainly from a larger provision for impairment and higher DD&A partially offset by a decrease in LOE and production taxes and an increase in gain on sale of assets.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales decreased $23,122,561, or 42%, for 2016, as compared to 2015. The decrease was due to decreased oil, NGL and natural gas prices of 31%, 31% and 30%, respectively, coupled with lower oil, NGL and natural gas volumes of 20%, 19% and 15%, respectively, in 2016.

The decrease in oil production was primarily the result of natural production decline in the Eagle Ford Shale, which was not offset by new production in the play due to significantly reduced drilling activity. To a lesser extent, declining production from various fields in western Oklahoma, the Texas Panhandle and the Northern Oklahoma Mississippian contributed to the decrease.

NGL production volume decreases were largely the result of natural production decline in the Anadarko Woodford Shale in western and central Oklahoma and the Anadarko Basin Granite Wash in western Oklahoma and the Texas Panhandle.

Natural gas production volume decreases were primarily the result of naturally declining production in the Fayetteville Shale. To a lesser extent, declining production from the Anadarko Basin Granite Wash and the southeastern Oklahoma Woodford Shale also contributed to the decrease.

Production by quarter for 2016 and 2015 was as follows (Mcfe):

	2016	2015
First quarter	3,143,400	3,737,483
Second quarter	2,786,303	3,455,265
Third quarter	2,887,821	3,315,899
Fourth quarter	2,678,725	3,221,086
Total	11,496,249	13,729,733

Lease Bonus and Rentals

Lease bonuses and rentals increased $5,725,390 in 2016. The increase was mainly due to the Company leasing 4,057 net mineral acres in Cochran County, Texas, 663 net mineral acres in Blaine, Canadian, Custer and Dewey Counties, Oklahoma, and 706 net mineral acres in Grady and McClain Counties, Oklahoma, in 2016. In 2015, the Company leased 2,407 net mineral acres in Andrews and Winkler Counties, Texas.

Gains (Losses) on Derivative Contracts

Gains on derivative contracts decreased $13,908,861 in 2016. The decrease was mainly due to the oil and, to a lesser extent, natural gas collars and fixed price swaps being more beneficial in 2015, as NYMEX oil and natural gas futures had fallen further below the floor of the collars and the fixed prices of the swaps. As of September 30, 2016, the Company’s natural gas costless collar contracts and natural gas fixed price swaps have expiration dates of October 2016 through December 2017; the oil costless collar contracts have expiration dates of October 2016 through March 2017.

Lease Operating Expenses (LOE)

LOE decreased $3,882,319 or 22% in 2016. LOE costs per Mcfe of production decreased from $1.27 in 2015 to $1.18 in 2016. The total LOE decrease was largely due to decreased field operating costs of $2,604,510 in 2016, compared to 2015. Field operating costs were $0.70 per Mcfe in 2016, compared to $0.78 per Mcfe in 2015, a 10% decrease. This decrease in rate was 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 $1,277,809 in 2016, as compared to 2015. The decrease in the amount in 2016 is the result of decreased oil, NGL and natural gas production and sales. On a per Mcfe basis, these fees decreased $0.01. Natural gas sales bear the large majority of the handling fees. Handling fees are charged either as a percent of sales or based on production volumes.

Production Taxes

Production taxes decreased $630,670 or 37% in 2016, as compared to 2015. The decrease in amount was primarily the result of decreased oil, NGL and natural gas sales of $23,122,561 during 2016. Production taxes as a percentage of oil, NGL and natural gas sales increased slightly from 3.1% in 2015 to 3.4% in 2016. The increase in tax rate was the result of the expiration of production tax discounts on some 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. The low overall production tax rate in both years was due to a large proportion of the Company's oil and natural gas revenues coming from horizontally drilled wells, which are eligible for reduced Oklahoma and Arkansas production tax rates in the first few years of production.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $666,426 in 2016. DD&A per Mcfe was $2.13 in 2016, compared to $1.74 in 2015. DD&A increased $4,541,529 as the result of a $0.39 increase in the DD&A rate. This rate increase was principally due to lower oil, NGL and natural gas prices utilized in the reserve calculations during 2016, as compared to 2015, 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. An offsetting decrease of $3,875,103 was due to oil, NGL and natural gas production volumes decreasing 16% collectively in 2016, compared to 2015.

Provision for Impairment

Provision for impairment increased $6,992,080 in 2016, as compared to 2015. During 2016, impairment of $12,001,271 was recorded on 44 fields primarily in Oklahoma, Kansas and Texas. Two fields in western Oklahoma and the Texas Panhandle accounted for $7,548,533 or 63% of the impairment due mainly to declining oil, NGL and natural gas prices. During 2015, impairment of $5,009,191 was recorded on 27 fields primarily in Oklahoma, Kansas and Texas. One oil field in Hemphill County, Texas, accounted for $1,846,488 of the impairment due mainly to declining oil prices.

Loss (Gain) on Asset Sales and Other

Loss (gain) on asset sales and other was a net gain of $2,576,237 in 2016, as compared to a net gain of $685,369 in 2015. The net gain in 2016 was largely due to the gain on sale of assets from two of the Company's partnerships. The net gain in 2015 was mainly the result of a lawsuit settlement related to participation rights on some of the Company's mineral acreage in Arkansas and higher income from partnerships.

Interest Expense

Interest expense decreased $205,864 in 2016, as compared to 2015. The decrease was due to a lower outstanding debt balance in 2016.

General and Administrative Costs (G&A)

G&A decreased $199,592 in 2016, as compared to 2015. This decrease was primarily the result of lower legal and technical consulting fees in 2016.

Provision (Benefit) for Income Taxes

The 2016 benefit for income taxes of $7,711,000 was based on a pre-tax loss of $17,997,884, as compared to a provision for income taxes of $4,836,000 in 2015, based on a pre-tax income of $14,157,341. The effective tax rate for 2016 was 43%, compared to an effective tax rate for 2015 of 34%. 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 in 2016.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2017, the Company had positive working capital of $6,451,356, as compared to positive working capital of $1,787,560 at September 30, 2016.

Liquidity

Cash and cash equivalents were $557,791 as of September 30, 2017, compared to $471,213 at September 30, 2016, an increase of $86,578. Cash flows for the 12 months ended September 30 are summarized as follows:

Net cash provided (used) by:

	2017	2016	Change
Operating activities	$20,758,192	$22,639,151	$(1,880,959)
Investing activities	(25,107,760)	565,617	(25,673,377)
Financing activities	4,436,146	(23,337,470)	27,773,616
Increase (decrease) in cash and cash equivalents	$86,578	$(132,702)	$219,280

(41)

Operating activities:

Net cash provided by operating activities decreased $1,880,959 during 2017, as compared to 2016, 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 increased $2,467,494.
- Decreased income tax payments of $1,309,905.
- Decreased net receipts on derivative contracts of $4,247,270.
- Decreased payments for interest expense of $152,596.
- Decreased payments for G&A and other expense of $205,658.
- Decreased payments for field operating expenses of $1,085,802.
- Decreased lease bonus receipts of $2,855,144.

Investing activities:

Net cash used in investing activities increased $25,673,377 during 2017, as compared to 2016, due to:

- Higher drilling and completion activity during 2017 increased capital expenditures by $21,821,662.
- Lower proceeds from sale of assets of $3,778,026.

Financing activities:

Net cash used by financing activities decreased $27,773,616 during 2017, as compared to 2016, the result of the following:

- During 2017, net borrowings increased $7,722,000. During 2016, net borrowings decreased $20,500,000.

Capital Resources

Capital expenditures to drill and complete wells increased $21,821,662 (547%) in 2017, as compared to 2016. The Company received 119 well proposals in fiscal 2017, and working interest participation decisions were as follows: 41 wells met the Company's participation criteria and elections were made to participate and 78 wells did not meet participation criteria with no participation elected.

The Company participated in eight BP operated southeastern Oklahoma Woodford wells with an average working interest of 20% and an average net revenue interest of 27.4%. All eight wells have been drilled. Four of those wells were completed and began producing in the second quarter of 2017. The remaining four wells have been completed and started producing in the third quarter of 2017.

The Company agreed to participate in six Anadarko Basin Woodford wells, operated by Cimarex Energy, with 17.5% working interest and 16.25% net revenue interest. All six wells have been drilled, completed and started producing in the fourth quarter of 2017.

The Company also participated in a continuous 10-well drilling program utilizing one rig on our Eagle Ford Shale leasehold. All 10 wells in this program have been drilled and the first two wells were completed and started producing in April 2017. The next four wells were completed and started producing in the fourth quarter of 2017. The remaining four wells were completed and began producing in the first quarter of 2018.

Activity from these three plays significantly increased our capital expenditures in fiscal 2017 compared to fiscal 2016. At this time, we do not have any similar material commitments for capital expenditures in 2018.

Oil, NGL and natural gas production volumes decreased 3% on an Mcfe basis during 2017, as compared to 2016. Higher drilling activity during 2017 resulted in new production coming on line that mostly offset the natural decline of existing wells.

Oil production decreased 15%, primarily the result of the production decline in the Eagle Ford Shale. To a lesser extent, declining production from various fields in western Oklahoma, the Texas Panhandle and Bakken Shale also contributed to the decrease. These decreases were partially offset by new production added in the Eagle Ford Shale on six wells in the second half of 2017.

NGL production increased 2%, largely the result of new production coming online in the Anadarko Woodford and Eagle Ford Shale. This more than offset the natural decline in the Anadarko Woodford Shale in western and central Oklahoma and the Anadarko Basin Granite Wash in western Oklahoma and the Texas Panhandle.

Natural gas production decreased 1%, principally due to declining production in the Fayetteville Shale. To a much lesser extent, declining production from the Anadarko Woodford Shale in western and central Oklahoma, the Anadarko Basin Granite Wash and the southeastern Oklahoma Woodford Shale also contributed to the decrease. The decline was mostly offset as a result of new well drilling in southeastern Oklahoma Woodford Shale and Anadarko Woodford Shale.

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 2018 capital expenditures for drilling and completion projects difficult to forecast.

Net cash provided by all of our operating activities allowed the Company to fund most of the capital expenditures, overhead costs, treasury stock purchases and dividend payments, while only increasing the Company's outstanding borrowings on the credit facility by $7.7 million during 2017. The Company received lease bonus payments during 2017 totaling approximately $5.1 million. Looking forward, the cash flow 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. However, management will continue to strategically evaluate the merit of leasing certain of the Company's mineral acres.

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 1 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" 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:

	Twelve months ended 9/30/2017
Cash provided by operating activities	$20,758,192
Cash used for (provided by):	
Capital expenditures - drilling and completion of wells	25,807,897
Quarterly dividends of $0.04 per share	2,684,001
Treasury stock purchases	601,853
Net payments (borrowings) on credit facility	(7,722,000)
Proceeds from sales of assets	(723,700)
Other investing activities	23,563
Net cash used	20,671,614
Net increase (decrease) in cash	$86,578

Outstanding borrowings on the credit facility at September 30, 2017, were $52,222,000.

Looking forward, the Company intends 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 activities, cash on hand and borrowings utilizing our bank credit facility. Any excess cash is intended to be used to reduce existing bank debt. The Company had availability of $27,778,000 under its revolving credit facility and was in compliance with its debt covenants at September 30, 2017. In October, the Company renegotiated and extended its credit facility. The new maturity date is November 20, 2022. The borrowing base under the credit facility was also redetermined in October 2017 and left unchanged at $80 million, which is a level that is expected to provide ample liquidity for the Company to continue to employ its normal operating strategies.

On November 6, 2017, the Company filed a shelf registration statement on Form S-3 with the SEC to give us the ability to sell up to $75 million in securities, including common stock, preferred stock, debt securities, warrants and units in amounts to be determined at the time of an offering. Any such offering, if it does occur, may happen in one or more transactions. The specific terms of any securities to be sold will be described in supplemental filings with the SEC. The registration statement will expire on November 6, 2020. The Company has no current plans to issue securities under the shelf registration statement.

Based on expected capital expenditure levels, anticipated cash provided by operating activities for 2018, combined with availability under its credit facility, the Company has sufficient liquidity to fund its ongoing operations.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a credit facility with a group of banks headed by Bank of Oklahoma (BOK) consisting of a revolving loan of $200,000,000, which is subject to a semi-annual borrowing base determination. The current borrowing base is $80,000,000 and is secured by certain of the Company's properties with a carrying value of $152,025,984 at September 30, 2017. The revolving loan matures on November 30, 2022. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the BOK prime rate plus a range of 0.375% to 1.250%, or 30 day LIBOR plus a range of 1.875% to 2.750% annually. At September 30, 2017, the effective rate was 3.72%. The election of BOK prime or LIBOR is at the Company's discretion. The interest rate spread from LIBOR or the prime rate increases as the ratio of the loan balance to the borrowing base increases.

Determinations of the borrowing base are made semi-annually (usually June and December) or whenever the banks, in their sole discretion, believe there has been a material change in the value of the Company's oil and natural gas properties. In October 2017, during the renegotiation of our credit facility, the borrowing base was redetermined by the banks and left unchanged at $80,000,000. 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 by the bank agreement – current assets includes availability under outstanding credit facility) of no less than 1.0 to 1.0 and a funded debt to EBITDA (trailing 12 months as defined by bank agreement – traditional EBITDA with the unrealized gain or loss on derivative contracts also removed from earnings) of no more than 4.0 to 1.0. At September 30, 2017, the Company was in compliance with the covenants of the loan agreement and had $27,778,000 of availability under its outstanding credit facility.

The table below summarizes the Company's contractual obligations and commitments as of September 30, 2017:

Contractual Obligations and Commitments	Payments due by period Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$52,222,000	$-	$-	$ -	$52,222,000
Building lease	$539,597	$206,665	$332,932	$	$-

The Company's building lease is accounted for as an operating lease and therefore the leased asset and associated liabilities of future rent payments are not included on the Company's balance sheets.

At September 30, 2017, the Company's derivative contracts were in a net asset position of $516,159. The ultimate settlement amounts of the derivative contracts are unknown because they are subject to continuing market risk. Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts.

As of September 30, 2017, the Company's estimate for asset retirement obligations was $3,196,889. Asset retirement obligations represent the Company's share of the future expenditures to plug and abandon the wells in which the Company owns a working interest at the end of their economic lives. These amounts were not included in the schedule above due to the uncertainty of timing of the obligations. Please read Note 1 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

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. Existing rules must be interpreted 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, NGL and natural gas reserve estimation; derivative contracts; impairment of assets; oil, NGL and natural gas sales revenue accruals; refundable production taxes and provision for income taxes. 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, NGL and natural gas sales revenue accrual is particularly subject to estimate inaccuracies due to the Company's status as a non-operator on all of its properties. As such, production and price information obtained from well operators is substantially delayed. This causes the estimation of recent production and prices used in the oil, NGL and natural gas revenue accrual to be subject to future change.

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. These estimates affect the unaudited standardized measure disclosures included in Note 11 to the financial statements in Item 8 – "Financial Statements and Supplementary Data," as well as DD&A and impairment calculations. Changes in crude oil, NGL and natural gas reserve estimates affect the Company's calculation of DD&A, asset retirement obligations 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 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. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing prices which are updated through the current period. In accordance with the SEC rules, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. Based on the Company's 2017 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $1,839,755 annual change in DD&A expense. Crude oil, NGL and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. 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.

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. This means exploration expenses, including geological and geophysical costs, non-producing lease impairment, 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 (the ratio of oil, NGL and natural gas volumes produced to total proved or proved developed reserves is used to amortize the remaining asset basis on each producing property) as oil, NGL 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 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.

Derivative Contracts

The Company has entered into oil and natural gas costless collar contracts and oil and natural gas fixed swap contracts. These instruments are intended to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. 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. 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 contracts cover only a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative instruments expose the Company to risk of financial loss and may 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 Company is required to recognize all derivative instruments as either assets or liabilities in the 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. At September 30, 2017, the Company had no derivative contracts designated as cash flow hedges, and therefore, changes in the fair value of derivatives are reflected in earnings.

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, NGL and natural gas; future production costs; estimates of future oil, NGL and natural gas reserves to be recovered and the timing thereof; 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 oil, NGL and natural gas and a discount rate in line with the discount rate we believe is most commonly used by market participants (10% for all periods presented). 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. A further reduction in oil, NGL 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 (as was the case at September 30, 2017). 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, NGL and Natural Gas Sales Revenue Accrual

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil, NGL and natural gas sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, and oil, NGL and natural gas index prices local to each well are used to estimate the accrual of revenue on these wells. Obtaining timely 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, NGL 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, NGL and natural gas. These variables could lead to an over or under accrual of oil, NGL and natural gas sales at the end of any particular quarter. Based on past history, the Company's estimated accruals have 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. To calculate the exact excess percentage depletion allowance, a well-by-well calculation is, and can only be, performed at the end of each fiscal year. During interim periods, an estimate is made taking into account historical data and current pricing. The Company has certain state net operating loss carry forwards (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. As of September 30, 2017, the Company had no valuation allowances on 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 generally accepted 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 7A 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 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 2018 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 2018 derivative contracts (see below), the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $819,453 for operating revenue based on the Company’s prior year natural gas volumes. The price sensitivity in 2018 for each $1.00 per barrel change in wellhead oil is approximately $310,677 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 $0.10 in the NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $293,000. For the Company’s natural gas collars, a change of $0.10 in the NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $327,000. For the Company’s oil fixed price swaps, a change of $1.00 in the NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $108,000. 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 $141,000. See Note 1 to the financial statements included in Item 8 – “Financial Statements and Supplementary Data” for additional information regarding the derivative contracts.

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 facility. The revolving loan bears interest at the BOK prime rate plus from 0.375% to 1.250%, or 30 day LIBOR plus from 1.875% to 2.750%. At September 30, 2017, the Company had $52,222,000 outstanding under this facility and the effective interest rate was 3.72%. At this point, the Company does not believe that its liquidity has been materially affected by the debt market uncertainties noted in the last few years and the Company does not believe that its liquidity will be impacted in the near future.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Annual Report on Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934 (the "Exchange Act") as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles in the United States, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2017. In making this assessment, the Company's management used the criteria set forth in Internal Control – Integrated Framework (as updated in 2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, management has concluded that, as of September 30, 2017, the Company's internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. This report appears on the following page.

Report of Independent Registered Public Accounting Firm

on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of

Panhandle Oil and Gas Inc.

We have audited Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2017, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Panhandle Oil and Gas Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Panhandle Oil and Gas Inc. maintained, in all material respects, effective internal control over financial reporting as of September 30, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheets of Panhandle Oil and Gas Inc. as of September 30, 2017 and 2016, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2017 and our report dated December 12, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 12, 2017

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of

Panhandle Oil and Gas Inc.

We have audited the accompanying balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2017 and 2016, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2017. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Panhandle Oil and Gas Inc. at September 30, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2017, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated December 12, 2017, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 12, 2017

Panhandle Oil and Gas Inc.

Balance Sheets

	September 30, 2017	2016
Assets		
Current Assets:		
Cash and cash equivalents	$557,791	$471,213
Oil, NGL and natural gas sales receivables (net of allowance for uncollectable accounts)	7,585,485	5,287,229
Refundable income taxes	489,945	83,874
Derivative contracts, net	544,924	-
Assets held for sale	557,750	-
Other	253,480	419,037
Total current assets	9,989,375	6,261,353
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	434,571,516	434,469,093
Non-producing oil and natural gas properties	7,428,927	7,574,649
Other	1,067,894	1,069,658
	443,068,337	443,113,400
Less accumulated depreciation, depletion and amortization	(246,483,979)	(251,707,749)
Net properties and equipment	196,584,358	191,405,651
Investments	170,486	157,322
Total assets	$206,744,219	$197,824,326

(Continued on next page)

See accompanying notes.

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Panhandle Oil and Gas Inc.

Balance Sheets

	September 30, 2017	2016
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$1,847,230	$2,351,623
Derivative contracts, net	-	403,612
Accrued liabilities and other	1,690,789	1,718,558
Total current liabilities	3,538,019	4,473,793
Long-term debt	52,222,000	44,500,000
Deferred income taxes	31,051,007	30,676,007
Asset retirement obligations	3,196,889	2,958,048
Derivative contracts, net	28,765	24,659
Stockholders' equity:		
Class A voting common stock, $0.0166 par value; 24,000,000 shares authorized; 16,863,004 issued at September 30, 2017 and 2016	280,938	280,938
Capital in excess of par value	2,726,444	3,191,056
Deferred directors' compensation	3,459,909	3,403,213
Retained earnings	113,330,216	112,482,284
	119,797,507	119,357,491
Treasury stock, at cost; 184,988 shares at September 30, 2017, and 262,708 shares at September 30, 2016	(3,089,968)	(4,165,672)
Total stockholders' equity	116,707,539	115,191,819
Total liabilities and stockholders' equity	$206,744,219	$197,824,326

See accompanying notes.

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Panhandle Oil and Gas Inc.

Statements of Operations

	Year ended September 30, 2017	2016	2015
Revenues:			
Oil, NGL and natural gas sales	$39,935,912	$31,411,353	$54,533,914
Lease bonuses and rentals	5,149,297	7,735,785	2,010,395
Gains (losses) on derivative contracts	1,249,840	(86,355)	13,822,506
	46,335,049	39,060,783	70,366,815
Costs and expenses:			
Lease operating expenses	12,682,969	13,590,089	17,472,408
Production taxes	1,548,399	1,071,632	1,702,302
Depreciation, depletion and amortization	18,397,548	24,487,565	23,821,139
Provision for impairment	662,990	12,001,271	5,009,191
Loss (gain) on asset sales and other	105,830	(2,576,237)	(685,369)
Interest expense	1,275,138	1,344,619	1,550,483
General and administrative	7,441,242	7,139,728	7,339,320
	42,114,116	57,058,667	56,209,474
Income (loss) before provision (benefit) for income taxes	4,220,933	(17,997,884)	14,157,341
Provision (benefit) for income taxes	689,000	(7,711,000)	4,836,000
Net income (loss)	$3,531,933	$(10,286,884)	$9,321,341
Basic and diluted earnings (loss) per common share	$0.21	$(0.61)	$0.56

See accompanying notes.

Panhandle Oil and Gas Inc.

Statements of Stockholders' Equity

	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)	$119,188,653
Purchase of treasury stock	-	-	-	-	-	(12,719)	(242,313)	(242,313)
Issuance of treasury shares to ESOP	-	-	3,437	-	-	11,455	181,676	185,113
Restricted stock awards	-	-	895,127	-	-	-	-	895,127
Distribution of restricted stock to officers and directors	-	-	(782,832)	-	-	48,633	766,301	(16,531)
Distribution of deferred directors' compensation	-	-	16,044	(328,415)	-	22,372	352,359	39,988
Common shares to be issued to directors for services	-	-	-	302,353	-	-	-	302,353
Dividends declared ($0.16 per share)	-	-	-	-	(2,669,056)	-	-	(2,669,056)
Net income (loss)	-	-	-	-	9,321,341	-	-	9,321,341
Balances at September 30, 2015	16,863,004	$280,938	$2,993,119	$3,084,289	$125,446,473	(302,623)	$(4,800,144)	$127,004,675
	-	-	-	-	-	(7,477)	(117,165)	(117,165)

Purchase of treasury stock								
Issuance of treasury shares to ESOP	-	-	19,068	-	-	11,418	181,090	200,158
Restricted stock awards	-	-	781,479	-	-	-	-	781,479
Distribution of restricted stock to officers and directors	-	-	(601,779)	-	-	35,257	559,175	(42,604)
Distribution of deferred directors' compensation	-	-	(831)	(10,541)	-	717	11,372	-
Common shares to be issued to directors for services	-	-	-	329,465	-	-	-	329,465
Dividends declared ($0.16 per share)	-	-	-	-	(2,677,305)	-	-	(2,677,305)
Net income (loss)	-	-	-	-	(10,286,884)	-	-	(10,286,884)
Balances at September 30, 2016	16,863,004	$280,938	$3,191,056	$3,403,213	$112,482,284	(262,708)	$(4,165,672)	$115,191,819
Purchase of treasury stock	-	-	-	-	-	(25,742)	(601,853)	(601,853)
Issuance of treasury shares to ESOP	-	-	93,192	-	-	13,125	219,188	312,380
Restricted stock awards	-	-	597,940	-	-	-	-	597,940
Distribution of restricted stock to officers and directors	-	-	(1,010,275)	-	-	63,121	1,010,938	663
	-	-	(145,469)	(301,962)	-	27,216	447,431	-

Distribution of deferred directors' compensation								
Common shares to be issued to directors for services	-	-	-	358,658	-	-	-	358,658
Dividends declared ($0.16 per share)	-	-	-	-	(2,684,001)	-	-	(2,684,001)
Net income (loss)	-	-	-	-	3,531,933	-	-	3,531,933
Balances at September 30, 2017	16,863,004	$280,938	$2,726,444	$3,459,909	$113,330,216	(184,988)	$(3,089,968)	$116,707,539

See accompanying notes.

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Panhandle Oil and Gas Inc.

Statements of Cash Flows

	Year ended September 30, 2017	2016	2015
Operating Activities			
Net income (loss)	$3,531,933	$(10,286,884)	$9,321,341
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	18,397,548	24,487,565	23,821,139
Impairment	662,990	12,001,271	5,009,191
Provision for deferred income taxes	375,000	(9,960,000)	2,672,000
Gain from leasing fee mineral acreage	(5,147,957)	(7,732,023)	(2,007,993)
Proceeds from leasing fee mineral acreage	5,194,290	8,049,434	2,053,900
Net (gain) loss on sales of assets	94,889	(2,688,408)	-
Common stock contributed to ESOP	312,380	200,158	185,113
Common stock (unissued) to Directors' Deferred Compensation Plan	358,658	329,465	302,353
Restricted stock awards	597,940	781,479	895,127
Other	(5,783)	81,606	449,905
Cash provided (used) by changes in assets and liabilities:			
Oil, NGL and natural gas sales receivables	(2,298,256)	2,589,146	8,151,379
Fair value of derivative contracts	(944,430)	4,639,035	(2,308,922)
Refundable income taxes	(406,071)	262,023	(345,897)
Other current assets	165,557	308,980	252,807
Accounts payable	(103,389)	(811,749)	(343,186)
Income taxes payable	-	-	(523,843)
Accrued liabilities	(27,107)	388,053	40,500
Total adjustments	17,226,259	32,926,035	38,303,573
Net cash provided by operating activities	20,758,192	22,639,151	47,624,914

(Continued on next page)

Panhandle Oil and Gas Inc.

Statements of Cash Flows (continued)

	Year ended September 30, 2017	2016	2015
Investing Activities			
Capital expenditures, including dry hole costs	$(25,807,897)	$(3,986,235)	$(30,800,625)
Acquisition of working interest properties	-	-	(308,180)
Investments in partnerships	(23,563)	50,126	(533,580)
Proceeds from sales of assets	723,700	4,501,726	-
Net cash used in investing activities	(25,107,760)	565,617	(31,642,385)
Financing Activities			
Borrowings under debt agreement	27,809,185	12,339,101	25,833,116
Payments of loan principal	(20,087,185)	(32,839,101)	(38,833,116)
Purchases of treasury stock	(601,853)	(117,165)	(242,313)
Payments of dividends	(2,684,001)	(2,677,305)	(2,669,056)
Excess tax benefit on stock-based compensation	-	(43,000)	23,000
Net cash provided by (used in) financing activities	4,436,146	(23,337,470)	(15,888,369)
Increase (decrease) in cash and cash equivalents	86,578	(132,702)	94,160
Cash and cash equivalents at beginning of year	471,213	603,915	509,755
Cash and cash equivalents at end of year	$557,791	$471,213	$603,915
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$1,212,878	$1,365,474	$1,558,885
Income taxes paid, net of refunds received	$720,072	$2,029,977	$3,009,939
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$624,893	$14,095	$70,529
Gross additions to properties and equipment	$25,406,894	$5,118,733	$26,183,115
Net (increase) decrease in accounts payable for properties and equipment additions	401,003	(1,132,498)	4,925,690
Capital expenditures, including dry hole costs	$25,807,897	$3,986,235	$31,108,805

See accompanying notes.

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Panhandle Oil and Gas Inc.

Notes to Financial Statements

September 30, 2017, 2016 and 2015

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Through management of its fee mineral and leasehold acreage, the Company's principal line of business is to explore for, develop, acquire, produce and sell oil, NGL and natural gas. Panhandle's mineral and leasehold properties and other oil and natural gas interests are all located in the contiguous United States, primarily in Arkansas, New Mexico, North Dakota, Oklahoma and Texas, with properties located in several other states. The Company's oil, NGL and natural gas production is from interests in 6,095 wells located principally in Arkansas, Oklahoma and Texas. The Company is not the operator of any wells. Approximately 55% of oil, NGL and natural gas revenues were derived from the sale of natural gas in 2017. Approximately 74% of the Company's total sales volumes in 2017 were derived from natural gas. Substantially all the Company's oil, NGL and natural gas production is sold through the operators of the wells. From time to time, the Company sells certain non-material, non-core or small-interest oil and natural gas properties in the normal course of business.

Basis of Presentation

Certain amounts (income from partnerships, exploration costs, bad debt expense (recovery) and loss (gain) on asset sales and other in the Statements of Operations) in the prior years have been reclassified to conform to the current year presentation.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of crude oil, NGL and natural gas reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. On an annual basis, with a semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of crude oil, NGL 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. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. For impairment purposes, projected future crude oil, NGL and natural gas prices as estimated by management are used. Crude oil, NGL and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Management uses projected future crude oil, NGL and natural gas pricing assumptions to prepare estimates of crude oil, NGL and natural gas reserves used in formulating management's overall operating decisions.

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil, NGL and natural gas sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, and oil, NGL and natural gas index prices local to each well are used to 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, NGL 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, NGL and natural gas. These variables could lead to an over or under accrual of oil, NGL and natural gas sales at the end of any particular quarter. Based on past history, the Company's estimated accrual has been materially accurate.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in short-term investments with original maturities of three months or less.

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

The Company sells oil, NGL and natural gas to various customers, recognizing revenues as oil, NGL and natural gas is produced and sold. Charges for compression, marketing, gathering and transportation of natural gas are included in lease operating expenses.

The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has underproduced or overproduced its ownership percentage in a property. Under this method, a receivable or liability is recorded to the extent that an underproduced or overproduced position in a well cannot be recouped through the production of remaining reserves. At September 30, 2017 and 2016, the Company had no material natural gas imbalances.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Company's accounts receivable are due from purchasers of oil, NGL and natural gas or operators of the oil and natural gas properties. Oil, NGL and natural gas sales receivables are generally unsecured. This industry concentration has the potential to impact our overall exposure to credit risk, in that the purchasers of our oil, NGL and natural gas and the operators of the properties in which we have an interest may be similarly affected by changes in

economic, industry or other conditions. During 2017 and 2016, the Company’s reserve for bad debt expense was not material.

Oil and Natural Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and natural gas producing activities. Intangible drilling and other costs of successful wells and development dry holes are capitalized and amortized. The costs of exploratory wells are initially capitalized, but charged against income, if and when the well does not commercially produce. Oil and natural gas mineral and leasehold costs are capitalized when incurred.

It is common business practice in the petroleum industry to prepay drilling costs before spudding a well. The Company frequently fulfills these prepayment requirements with cash payments, but at times will utilize letters of credit to meet these obligations. As of September 30, 2017, the Company had no outstanding letters of credit.

Leasing of Mineral Rights

When the Company leases its mineral acreage to a third-party company, it retains a royalty interest in any future revenues from the production and sale of oil, NGL or natural gas, and often receives an up-front, non-refundable, cash payment (lease bonus) in addition to the retained royalty interest. A royalty interest does not bear any portion of the cost of drilling, completing or operating a well; these costs are borne by the working interest owners. The Company sometimes leases only a portion of its mineral acres in a tract and retains the right to participate as a working interest owner with the remainder.

The Company recognizes revenue from mineral lease bonus payments when it has received an executed lease agreement with a third-party company transferring the rights to explore for and produce any oil or natural gas they may find within the term of the lease, the payment has been collected, and the Company has no obligation to refund the payment. The Company accounts for its lease bonuses in accordance with the guidance set forth in ASC 932, and it recognizes the lease bonus as a cost recovery with any excess above its cost basis in the mineral being treated as a gain. The excess of lease bonus above the mineral basis is shown in the lease bonuses and rentals line item on the Company’s Statements of Operations.

Derivatives

The Company has entered into 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. 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. 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. These contracts cover only a portion of the Company’s oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative instruments expose the Company to risk of financial loss and may limit the benefit of future increases in prices. All of the Company’s

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

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.

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Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Derivative contracts in place as of September 30, 2017

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.47 ceiling
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.35 ceiling
April - December 2017	30,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.65 ceiling
May - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.60 ceiling
May - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.20 floor / $3.65 ceiling
January - March 2018	100,000 Mmbtu	NYMEX Henry Hub	$3.50 floor / $3.95 ceiling
January - March 2018	150,000 Mmbtu	NYMEX Henry Hub	$3.40 floor / $3.95 ceiling
January - December 2018	40,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.35 ceiling
January - December 2018	40,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.30 ceiling
Natural gas fixed price swaps			
January - December 2017	25,000 Mmbtu	NYMEX Henry Hub	$3.100
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.070
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.210
April - December 2017	30,000 Mmbtu	NYMEX Henry Hub	$3.300
July - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.510
August - December 2017	100,000 Mmbtu	NYMEX Henry Hub	$3.095
January - March 2018	50,000 Mmbtu	NYMEX Henry Hub	$3.700
January - March 2018	75,000 Mmbtu	NYMEX Henry Hub	$3.575
January - March 2018	100,000 Mmbtu	NYMEX Henry Hub	$3.520
January - December 2018	50,000 Mmbtu	NYMEX Henry Hub	$3.080
Oil costless collars			
January - December 2017	3,000 Bbls	NYMEX WTI	$50.00 floor / $55.00 ceiling
January - December 2017	3,000 Bbls	NYMEX WTI	$52.00 floor / $58.00 ceiling
January - December 2017	3,000 Bbls	NYMEX WTI	$53.00 floor / $57.75 ceiling
April - December 2017	2,000 Bbls	NYMEX WTI	$50.00 floor / $57.50 ceiling
July - December 2017	5,000 Bbls	NYMEX WTI	$45.00 floor / $56.25 ceiling
January - June 2018	2,000 Bbls	NYMEX WTI	$47.50 floor / $52.75 ceiling
January - December 2018	2,000 Bbls	NYMEX WTI	$47.50 floor / $52.50 ceiling
January - December 2018	2,000 Bbls	NYMEX WTI	$48.00 floor / $53.25 ceiling
Oil fixed price swaps			
January - December 2017	3,000 Bbls	NYMEX WTI	$53.89
April - December 2017	2,000 Bbls	NYMEX WTI	$54.20
January - March 2018	4,000 Bbls	NYMEX WTI	$54.00
January - June 2018	4,000 Bbls	NYMEX WTI	$51.25
January - December 2018	3,000 Bbls	NYMEX WTI	$50.72
January - December 2018	2,000 Bbls	NYMEX WTI	$52.02

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Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Derivative contracts in place as of September 30, 2016

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
April - October 2016	200,000 Mmbtu	NYMEX Henry Hub	$1.95 floor / $2.40 ceiling
October - December 2016	70,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.05 ceiling
October - December 2016	50,000 Mmbtu	NYMEX Henry Hub	$2.90 floor / $3.40 ceiling
November 2016 - March 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.25 floor / $3.65 ceiling
November 2016 - March 2017	80,000 Mmbtu	NYMEX Henry Hub	$2.25 floor / $3.95 ceiling
November 2016 - March 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.60 floor / $3.25 ceiling
January - June 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.85 floor / $3.35 ceiling
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.47 ceiling
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.35 ceiling
Natural gas fixed price swaps			
October 2016	100,000 Mmbtu	NYMEX Henry Hub	$2.410
October 2016 - March 2017	25,000 Mmbtu	NYMEX Henry Hub	$3.200
November 2016 - April 2017	80,000 Mmbtu	NYMEX Henry Hub	$2.955
January - December 2017	25,000 Mmbtu	NYMEX Henry Hub	$3.100
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.070
Oil costless collars			
July - December 2016	3,000 Bbls	NYMEX WTI	$35.00 floor / $49.00 ceiling
October - December 2016	3,000 Bbls	NYMEX WTI	$40.00 floor / $47.25 ceiling
October 2016 - March 2017	3,000 Bbls	NYMEX WTI	$40.00 floor / $58.50 ceiling
October 2016 - March 2017	3,000 Bbls	NYMEX WTI	$45.00 floor / $54.00 ceiling
October 2016 - March 2017	3,000 Bbls	NYMEX WTI	$45.00 floor / $55.50 ceiling

The Company has elected not to complete 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 $516,159 as of September 30, 2017, and a net liability of $428,271 as of September 30, 2016. Realized and unrealized gains and (losses) are recorded in gains (losses) on derivative contracts on the Company's Statement of Operations.

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 Balance Sheets. The following table summarizes and reconciles the Company's

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Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

derivative contracts' fair values at a gross level back to net fair value presentation on the Company's Balance Sheets at September 30, 2017, and September 30, 2016. The Company has offset all amounts subject to master netting agreements in the Company's Balance Sheets at September 30, 2017, and September 30, 2016.

	9/30/2017 Fair Value (a) Commodity Contracts				9/30/2016 Fair Value (a) Commodity Contracts			
	Current Assets	Current Liabilities	Non-Current Assets	Non-Current Liabilities	Current Assets	Current Liabilities	Non-Current Assets	Non-Current Liabilities
Gross amounts recognized	$735,702	$190,778	$ 9,439	$ 38,204	$68,235	$471,847	$ 4,759	$ 29,418
Offsetting adjustments	(190,778)	(190,778)	(9,439)	(9,439)	(68,235)	(68,235)	(4,759)	(4,759)
Net presentation on Balance Sheets	$544,924	$-	$ -	$ 28,765	$-	$403,612	$ -	$ 24,659

(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 only if the impact is deemed material. The impact of credit risk was immaterial for all periods presented.

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.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis.

	Fair Value Measurement at September 30, 2017			
	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	$ -	$ 364,606	$ -	$ 364,606
Derivative Contracts - Collars	$ -	$ -	$ 151,553	$ 151,553

	Fair Value Measurement at September 30, 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	$ -	$ (111,613)	$ -	$ (111,613)
Derivative Contracts - Collars	$ -	$ -	$ (316,658)	$ (316,658)

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 forward prices and 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.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

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

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value Assets (Liabilities) September 30, 2017
Oil Collars	Oil price volatility curve	0% - 29.06%	14.98 %	$ (60,331)
Natural Gas Collars	Gas price volatility curve	0% - 29.34%	18.13 %	$ 211,884

A reconciliation of the Company’s derivative contracts classified as Level 3 measurements is presented below.

	Derivatives
Net Asset (Liability) Balance of Level 3 as of October 1, 2016	$ (316,658)
Total gains or (losses):	
Included in earnings	460,061
Included in other comprehensive income (loss)	-
Purchases, issuances and settlements	8,150
Transfers in and out of Level 3	-
Net Asset (Liability) Balance of Level 3 as of September 30, 2017	$ 151,553

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.

	Year Ended September 30, 2017		2016	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties (a)	$ 567,077	$ 662,990	$ 9,877,905	$ 12,001,271

(a) At the end of each quarter, the Company assessed the carrying value of its producing properties for impairment. This assessment utilized estimates of future cash flows or fair value (selling price) less cost to sell if the property is held for sale. Significant judgments and assumptions in these assessments include estimates of future oil, NGL and natural gas prices using a forward NYMEX curve adjusted for projected inflation, 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 September 30, 2017, and September 30, 2016, the fair value of financial instruments approximated their carrying amounts. Financial instruments include long-term debt, which 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 relating to nonperformance risk for the debt agreements were considered necessary.

Depreciation, Depletion, Amortization and Impairment

Depreciation, depletion and amortization of the costs of producing oil and natural gas properties are generally computed using the unit-of-production method primarily on an individual property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent Consulting Petroleum Engineer. The Company's capitalized costs of drilling and equipping all development wells, and those exploratory wells that have found proved reserves, are amortized on a unit-of-production basis over the remaining life of associated proved developed reserves. Lease costs are amortized on a unit-of-production basis over the remaining life of associated total proved reserves. Depreciation of furniture and fixtures is computed using the straight-line method over estimated productive lives of five to eight years.

Non-producing oil and natural gas properties include non-producing minerals, which had a net book value of $3,079,008 and $3,349,567 at September 30, 2017 and 2016, respectively, consisting of perpetual ownership of mineral interests in several states, with 91% of the acreage in Arkansas, New Mexico, North Dakota, Oklahoma and Texas. As mentioned, these mineral rights are perpetual and have been accumulated over the 91-year life of the Company. There are approximately 198,176 net acres of non-producing minerals in more than 6,284 tracts owned by the Company. An average tract contains approximately 29 acres, and the average cost per acre is $40. Since inception, the Company has continually generated an interest in several thousand oil and natural gas wells using its ownership of the fee mineral acres as an ownership basis. There continues to be significant drilling and leasing activity each year on these mineral interests. Non-producing minerals are being amortized straight-line over a 33-year period. These assets are considered a long-term investment by the Company, as they do not expire (as do oil and natural gas leases). Given the above, management concluded that a long-term amortization was appropriate and that 33 years, based on past history and experience, was an appropriate period. Due to the fact that the minerals consist of a large number of properties, whose costs are not individually significant, and because virtually all are in the Company's core operating areas, the minerals are being amortized on an aggregate basis.

The Company recognizes impairment losses for long-lived assets when indicators of impairment are present and the undiscounted cash flows are not sufficient to recover the assets' carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted cash flow as estimated by the Company or fair value (sales price) less cost to sell if the property is held for sale. The Company's estimate of fair value of its oil and natural gas properties at September 30, 2017, is based on the best information available as of that date, including estimates of forward oil, NGL and natural gas prices and costs. The Company's oil and natural gas properties were reviewed for impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $662,990,

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Notes to Financial Statements (continued)

$12,001,271 and $5,009,191 for 2017, 2016 and 2015, respectively. 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.

At September 30, 2017, the Company had a group of 68 non-core marginal wells that were held for sale pending a final agreement with the buyer. The sale of these assets closed on October 12, 2017, for $557,750. As the selling price was less than the carrying value and these wells met the criteria of held for sale at September 30, 2017, the carrying amount of these assets was written down to fair value less cost to sell and an impairment expense was recognized for $616,711 (included in Provision for impairment line of Statement of Operations). The net amount of assets less accumulated DD&A ($14,929,309 and $14,371,559, respectively) was reclassed from noncurrent assets in Property and equipment to current assets as Assets held for sale on the Balance Sheets as of September 30, 2017.

Capitalized Interest

During 2017, 2016 and 2015, interest of $168,351, $24,929 and $148,493, respectively, was included in the Company's capital expenditures. Interest of $1,275,138, $1,344,619 and $1,550,483, respectively, was charged to expense during those periods. Interest is capitalized using a weighted average interest rate based on the Company's outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the unit-of-production method.

Asset Retirement Obligations

The Company owns interests in oil and natural gas properties, which may require expenditures to plug and abandon the wells upon the end of their economic lives. The fair value of legal obligations to retire and remove long-lived assets is recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, this cost is capitalized by increasing the carrying amount of the related properties and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties and equipment is depreciated over the useful life of the remaining asset. The Company does not have any assets restricted for the purpose of settling the asset retirement obligations.

The following table shows the activity for the years ended September 30, 2017 and 2016, relating to the Company's asset retirement obligations:

	2017	2016
Asset retirement obligations as of beginning of the year	$2,958,048	$2,824,944
Wells acquired or drilled	114,766	17,338
Wells sold or plugged	(548,634)	(12,956)
Revisions in estimated cash flows	536,536	-
Accretion of discount	136,173	128,722
Asset retirement obligations as of end of the year	$3,196,889	$2,958,048

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Notes to Financial Statements (continued)

The revisions in estimated cash flows in fiscal 2017 were due to increased plugging charges noted recently that were higher than previously estimated. As a non-operator, we do not control the plugging of wells in which we have a working interest and are not involved in the negotiation of the terms of the plugging contracts. Our estimate relies on information that we receive directly from operators as well as relevant information that we can gather from outside sources.

Environmental Costs

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays. The Company does not believe the existence of current environmental laws, or interpretations thereof, will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future effects on the Company of new laws or interpretations thereof. Since the Company does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. Panhandle carries liability and pollution control insurance. However, all risks are not insured due to the availability and cost of insurance.

Environmental liabilities, which historically have not been material, are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At September 30, 2017 and 2016, there were no such costs accrued.

Earnings (Loss) Per Share of Common Stock

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

Share-based Compensation

The Company recognizes current compensation costs for its Deferred Compensation Plan for Non-Employee Directors (the "Plan"). Compensation cost is recognized for the requisite directors' fees as earned and unissued stock is recorded to each director's account based on the fair market value of the stock at the date earned. The Plan provides that only upon retirement, termination or death of the director or upon a change in control of the Company, the shares accrued under the Plan may be issued to the director.

In accordance with guidance on accounting for employee stock ownership plans, the Company records the fair market value of the stock contributed into its ESOP as expense.

Restricted stock awards to officers provide for cliff vesting at the end of three or five years from the date of the awards. These restricted stock awards can be granted based on service time only (non-performance based) or subject to certain share price performance standards (performance based). Restricted stock awards to the non-employee directors provide for

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quarterly vesting during the calendar year of the award. The fair value of the awards on the grant date is ratably expensed over the vesting period in accordance with accounting guidance.

Income Taxes

The estimation of 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. 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 regulations. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities.

The threshold for recognizing the financial statement effect of a tax position is when it is more likely than not, based on the technical merits, that the position will be sustained by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with a taxing authority. The Company files 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 fiscal years prior to 2014.

The Company includes interest assessed by the taxing authorities in interest expense and penalties related to income taxes in general and administrative expense on its Statements of Operations. For fiscal September 30, 2017, 2016 and 2015, the Company's interest and penalties was not material. The Company does not believe it has any significant uncertain tax positions.

Adoption of New Accounting Pronouncements

In April 2015, the FASB issued Accounting Standards Update ("ASU") 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The update requires that debt issuance costs related to a recognized debt liability, such as senior notes, term loans and note payables, be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts. Under previous guidance, debt issuance costs were required to be presented in the balance sheet as an asset. 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.

In August 2015, the FASB issued ASU 2015-15, Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements, which allows for line-of-credit arrangements to be handled consistently with the presentation of debt issuance costs prior to ASU 2015-03 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.

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Notes to Financial Statements (continued)

The Company adopted ASU 2015-03 and ASU 2015-15 as of December 31, 2016. The Company elected to continue to show debt issuance costs associated with its credit facility (Company’s only debt) as assets versus a direct reduction of the debt liability. Therefore, the adoption had no impact on the Company's current and previously reported balance sheets, shareholders' equity, results of operations, or cash flows. In accordance with ASU 2015-15, unamortized debt issuance costs associated with the Company's credit facility, which amounted to $141,956 and $263,584 as of September 30, 2017, and September 30, 2016, respectively, remain reflected in "Other property and equipment" on the balance sheets.

In November 2015, the FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes. 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.

The Company early adopted ASU 2015-17 as of December 31, 2016, on a retrospective basis to all prior balance sheet periods presented. As a result of the adoption, the Company reclassified $310,900 as of September 30, 2016, from "Deferred income taxes" in current assets to “Deferred income tax, net” in long term liabilities on the balance sheets. Adoption of ASU 2015-17 had no impact on the Company's current and previously reported shareholders' equity, results of operations or cash flows. The affected prior period deferred income tax account balances presented throughout this report on Form 10-K have been adjusted to reflect the retroactive adoption of ASU 2015-17.

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments, which addresses certain issues where diversity in practice was identified and may change how an entity classifies certain cash receipts and cash payments on its statement of cash flows. The new guidance also clarifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. This guidance will generally be applied retrospectively and is effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption is permitted. All of the amendments in ASU 2016-15 are required to be adopted at the same time.

The Company early adopted ASU 2016-15 as of December 31, 2016. As a result of the adoption, the Company reclassified “Proceeds from leasing fee mineral acreage”, which totaled $5,194,290, $8,049,434 and $2,053,900 for the fiscal years ending September 30, 2017, 2016 and 2015, respectively, from Investing Activities to Operating Activities on the Condensed Statements of Cash Flows as these transactions are made in our normal course of business and represent operating activities based on the application of the predominance principle. As another result of this adoption, we are also electing to classify our distributions received from equity method investments using the Cumulative Earnings Approach. Distributions received are considered returns on investment and classified as cash inflows from operating activities, unless the investor’s cumulative distributions received less distributions received in prior periods that were determined to be returns of investment exceed cumulative equity in earnings recognized by the investor. When such an excess occurs, the current-period distribution up to this excess should be considered a return of investment and classified as cash inflows from investing activities. This election did not have any impact on our cash flow statements as the Company was already applying this approach. Adoption of ASU 2016-15 had no impact on the Company's current and previously reported shareholders' equity, results of operations or balance sheets. The affected prior period balances in the Condensed Statements of Cash Flows presented throughout this report on Form 10-K have been adjusted to reflect the retroactive adoption of ASU 2016-15.

In March 2016, the FASB issued ASU 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. The guidance changes how companies account for certain aspects of share-based payment awards, including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification in the statement of cash flows. The standard is effective for interim and annual reporting periods beginning after December 15, 2016, and will be adopted either prospectively, retrospectively or using a modified retrospective transition approach depending on the topic covered in the standard. Early adoption is permitted for any organization in any interim or annual period. On a prospective basis, companies will no longer record excess tax benefits and deficiencies in additional paid-in capital. Instead, excess tax benefits and deficiencies will be recognized as income tax expense or benefit in the income statement. This is expected to result in increased volatility in income tax expense/benefit and corresponding variations in the relationship between income tax expense/benefit and pre-tax income/loss from period to period. Also, companies will have to present excess tax benefits and deficiencies as operating activities on the statement of cash flows (prospectively or retrospectively). The new guidance will also require an employer to classify as a financing activity in its statement of cash flows the cash paid to a tax authority when shares are withheld to satisfy the employer’s statutory income tax withholding obligation.

The Company early adopted ASU 2016-09 as of October 1, 2016. As a result of the adoption, the Company recorded $238,000 of excess tax benefits from stock-based compensation in the “Provision (benefit) for income taxes” on the Condensed Statements of Operations in 2017 versus “Capital in excess of par” on the Condensed Balance Sheets in 2016 as was previously required. This part of the guidance is to be applied prospectively, so the prior period balances have not been reclassified. The Company also presented excess tax benefits from stock-based compensation in the “Operating Activities” section of the Condensed Statements of Cash Flows in the current period versus the “Financing Activities” section of the Condensed Statements of Cash Flows as was previously presented. The Company has elected to apply this part of the guidance prospectively, so the prior period balances have not been reclassified. The guidance also requires that companies present employees taxes paid upon vesting (using shares repurchased) as financing activities on the statement of cash flows (Purchases of Treasury Stock). This requirement had no impact on the Company, as this has been the practice historically. The Company is also electing to account for forfeitures of awards as they occur, instead of estimating a forfeiture amount. A cumulative-effect adjustment to retained earnings was not necessary for this transition as there were no material forfeitures estimated or incurred in the past. The adoption of this ASU could cause volatility in the effective tax rate going forward.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Continue as a Going Concern. The update defined management's responsibility to evaluate whether substantial doubt exists about an entity's ability to continue as a going concern. Professional auditing standards require auditors to evaluate the going concern presumption, but previously there was a lack of guidance in GAAP for financial statement preparers. This update requires management to perform a going concern evaluation effective for annual periods ending after December 15, 2016, and annual and interim periods thereafter. The Company adopted this standard in 2017 and management does not believe there is substantial doubt about the entity's ability to continue as a going concern.

New Accounting Pronouncements yet to be Adopted

In February 2016, the FASB issued its new lease accounting guidance in ASU 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. The guidance is effective for us beginning October 1, 2019, including interim periods within the fiscal year. 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. We are assessing the potential impact that this update will have on our financial statements.

In January 2016, the FASB issued ASU 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 us beginning October 1, 2018, including interim periods within the fiscal year. We are assessing the potential impact that this update will have on our financial statements.

In May 2014, the FASB issued ASU 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

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

potential impact that this update will have on our financial statements and the transition method that will be elected.

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.

2. COMMITMENTS

The Company leases office space in Oklahoma City, Oklahoma, under the terms of an operating lease expiring in April 2020. Future minimum rental payments under the terms of the lease are $206,665, $210,273 and $122,659 in 2018, 2019 and 2020, respectively. Total rent expense incurred by the Company was $206,366 in 2017, $202,083 in 2016 and $198,238 in 2015.

3. INCOME TAXES

The Company's provision (benefit) for income taxes is detailed as follows:

	2017	2016	2015
Current:			
Federal	$314,000	$2,166,000	$2,053,000
State	-	83,000	111,000
	314,000	2,249,000	2,164,000
Deferred:			
Federal	390,000	(8,597,000)	2,033,000
State	(15,000)	(1,363,000)	639,000
	375,000	(9,960,000)	2,672,000
	$689,000	$(7,711,000)	$4,836,000

The difference between the provision (benefit) for income taxes and the amount which would result from the application of the federal statutory rate to income before provision (benefit) for income taxes is analyzed below for the years ended September 30:

	2017	2016	2015
Provision (benefit) for income taxes at statutory rate	$1,477,327	$(6,299,259)	$4,955,069
Percentage depletion	(570,801)	(395,649)	(530,783)
State income taxes, net of federal provision (benefit)	3,900	(683,800)	487,500
Effect of graduated rates	85,644	(86,745)	(62,922)
Restricted stock tax benefit	(238,000)	-	-
Deferred directors compensation benefit	(79,000)	-	-
Other	9,930	(245,547)	(12,864)
	$689,000	$(7,711,000)	$4,836,000

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Notes to Financial Statements (continued)

Deferred tax assets and liabilities, resulting from differences between the financial statement carrying amounts and the tax basis of assets and liabilities, consist of the following at September 30:

	2017	2016
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$38,185,387	$33,656,415
Derivative contracts	200,786	-
	38,386,173	33,656,415
Deferred tax assets:		
State net operating loss carry forwards	655,741	259,981
AMT credit carry forwards	3,499,320	-
Deferred directors' compensation	1,295,333	1,273,279
Restricted stock expense	411,019	494,776
Derivative contracts	-	166,597
Statutory depletion carry forwards	634,405	-
Other	839,348	785,775
	7,335,166	2,980,408
Net deferred tax liabilities	$31,051,007	$30,676,007

At September 30, 2017, the Company had a deferred tax asset of $595,526 related to Oklahoma state income tax net operating loss (OK NOL) carry forwards expiring from 2029 to 2037. There is no valuation allowance for the OK NOL's, as management believes they will be utilized before they expire. The AMT carry forwards do not have an expiration date.

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 $80,000,000 and a maturity date of November 30, 2022. 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 $152,025,984 at September 30, 2017. The interest rate is based on BOK prime plus from 0.375% to 1.250%, or 30 day LIBOR plus from 1.875% to 2.750%. 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 September 30, 2017, the effective interest rate was 3.72%.

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.

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Notes to Financial Statements (continued)

Determinations of the borrowing base are made semi-annually (usually June and December) or whenever the banks, in their sole discretion, believe that there has been a material change in the value of the Company’s oil and natural gas properties. In October 2017, during the renegotiation of our credit facility, the borrowing base was redetermined by the banks and left unchanged at $80,000,000. 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 by the bank agreement – current assets includes availability under outstanding credit facility) of no less than 1.0 to 1.0 and a funded debt to EBITDA (trailing 12 months as defined by bank agreement – traditional EBITDA with the unrealized gain or loss on derivative contracts also removed from earnings) of no more than 4.0 to 1.0. At September 30, 2017, the Company was in compliance with the covenants of the loan agreement and had $27,778,000 of availability under its outstanding credit facility.

5. SHAREHOLDERS’ EQUITY

Upon approval by the shareholders of the Company’s 2010 Restricted Stock Plan in March 2010, the Board approved purchase of up to $1.5 million of the Company’s Common Stock, from time to time, equal to the aggregate number of shares of Common Stock awarded pursuant to the Company’s 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. Effective May 2014, the board of directors approved for management to make these purchases of the Company’s Common Stock at their discretion. The Board’s approval included an initial authorization to purchase up to $1.5 million of Common Stock, with a provision for subsequent authorizations without specific action by the Board. As the amount of Common Stock purchased under any authorization reaches $1.5 million, another $1.5 million is automatically authorized for Common Stock purchases unless the Board determines otherwise. Pursuant to these resolutions adopted by the Board, the purchase of additional $1.5 million increments of the Company’s Common Stock became authorized and approved effective March 2011, March 2012, and June 2013. As of September 30, 2017, $5,599,643 had been spent under the current program to purchase 370,950 shares. The shares are held in treasury and are accounted for using the cost method.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

6. EARNINGS (LOSS) PER SHARE

The following table sets forth the computation of earnings (loss) per share.

	Year ended September 30,		
	2017	2016	2015
Numerator for basic and diluted earnings (loss) per share:			
Net income (loss)	$3,531,933	$(10,286,884)	$9,321,341
Denominator for basic and diluted earnings per share:			
Weighted average shares (including for 2017, 2016 and 2015, unissued, vested directors' shares of 253,603, 263,057 and 246,442, respectively)	16,900,185	16,840,856	16,768,904

7. EMPLOYEE STOCK OWNERSHIP PLAN

The Company’s ESOP was established in 1984 and is a tax qualified, defined contribution plan that serves as the sole retirement plan for all its employees to which the Company makes contributions. Company contributions are made at the discretion of the Board and, to date, all contributions have been made in shares of Company Common Stock. The Company contributions are allocated to all ESOP participants in proportion to their compensation for the plan year, and 100% vesting occurs after three years of service. Any shares that do not vest are treated as forfeitures and are distributed among other vested employees. For contributions of Common Stock, the Company records as expense the fair market value of the stock contributed. The 252,542 shares of the Company’s Common Stock held by the plan as of September 30, 2017, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings-per-share computations and receive dividends.

Contributions to the plan consisted of:

Year	Shares	Amount
2017	13,125	$312,380
2016	11,418	$200,158
2015	11,455	$185,113

8. DEFERRED COMPENSATION PLAN FOR DIRECTORS

Annually, independent directors may elect to be included in the Panhandle Oil and Gas Inc. Deferred Directors' Compensation Plan for Non-Employee Directors (the "Plan"). The Plan provides that each independent 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, if and 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.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

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 Plan be issued to the director. The promise to issue such shares in the future is an unsecured obligation of the Company. As of September 30, 2017, there were 261,846 shares (272,564 shares at September 30, 2016) recorded under the Plan. The deferred balance outstanding at September 30, 2017, under the Plan was $3,459,909 ($3,403,213 at September 30, 2016). Expenses totaling $358,658, $329,465 and $302,353 were charged to the Company's results of operations for the years ended September 30, 2017, 2016 and 2015, respectively, and are included in general and administrative expense in the accompanying Statement of Operations.

9. 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 the Company can respond as necessary to provide competitive compensation in order to retain, attract and motivate officers of the Company and to align their interests with those of the Company's shareholders.

In June 2010, the Company began awarding shares of the Company's Common Stock as restricted stock (non-performance based) to certain officers. The restricted stock vests at the end of the vesting period and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares was based on the closing price of the shares on their award date and will be recognized as compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury.

In December 2010, the Company also began awarding shares of the Company's Common Stock, subject to certain share price performance standards (performance based), as restricted stock to certain officers. Vesting of these shares is based on the performance of the market price of the Common Stock over the vesting period. The fair value of the performance shares was estimated on the grant date using a Monte Carlo valuation model that factors in information, including the expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance shares. Compensation expense for the performance shares is a fixed amount determined at the grant date and is recognized over the vesting period regardless of whether performance shares are awarded at the end of the vesting period. Should the shares vest, they are expected to be issued out of shares held in treasury.

In May 2014, the Company also began awarding shares of the Company's Common Stock as restricted stock (non-performance based) to its non-employee directors. The restricted stock vests quarterly during the calendar year of the award and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares was based on the closing price of the shares on their award date and will be recognized as

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Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury.

Compensation expense for the restricted stock awards is recognized in G&A.

The following table summarizes the Company's pre-tax compensation expense for the years ended September 30, 2017, 2016 and 2015, related to the Company's performance based and non-performance based restricted stock.

	Year Ended September 30,		
	2017	2016	2015
Performance based, restricted stock	$233,122	$390,655	$480,159
Non-performance based, restricted stock	364,818	390,824	414,968
Total compensation expense	$597,940	$781,479	$895,127

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.

	Unrecognized Compensation Cost	Weighted Average Period (in years)
Performance based, restricted stock	$ 267,618	1.82
Non-performance based, restricted stock	240,126	1.44
Total	$ 507,744	

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

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

A summary of the status of unvested shares of restricted stock awards and changes is presented below:

	Performance Based Unvested Restricted Shares	Weighted Average Grant-Date Fair Value	Non-Performance Based Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of September 30, 2014	112,184	$ 8.42	56,353	$ 15.52
Granted	35,485	12.18	22,028	19.25
Vested	(10,209)	9.73	(38,415)	16.58
Forfeited	(25,209)	9.73	-	-
Unvested shares as of September 30, 2015	112,251	$ 9.20	39,966	$ 16.56
Granted	40,446	9.32	26,478	16.37
Vested	(10,197)	7.59	(23,433)	16.91
Forfeited	(28,083)	7.59	-	-
Unvested shares as of September 30, 2016	114,417	$ 9.78	43,011	$ 16.25
Granted	20,531	14.27	16,426	24.41
Vested	(34,672)	8.07	(28,449)	18.02
Forfeited	(1,186)	8.07	(5,991)	17.04
Unvested shares as of September 30, 2017	99,090	$ 11.33	24,997	$ 19.41

The intrinsic value of the vested shares in 2017 was $1,466,415.

10. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

Virtually all oil and natural gas producing activities of the Company are conducted within the contiguous United States (principally in Arkansas, Oklahoma and Texas) and represent substantially all of the business activities of the Company.

The following table shows sales, by percentage, through various operators/purchasers during 2017, 2016 and 2015.

	2017	2016	2015
Company A	18 %	23 %	23 %
Company B	13 %	12 %	14 %

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of oil and natural gas properties and related accumulated depreciation, depletion and amortization as of September 30 is as follows:

	2017	2016
Producing properties	$434,571,516	$434,469,093
Non-producing minerals	7,243,802	7,364,630
Non-producing leasehold	185,125	204,101
Exploratory wells in progress	-	5,917
	442,000,443	442,043,741
Accumulated depreciation, depletion and amortization	(245,640,247)	(251,004,735)
Net capitalized costs	$196,360,196	$191,039,006

Costs Incurred

For the years ended September 30, the Company incurred the following costs in oil and natural gas producing activities:

	2017	2016	2015
Property acquisition costs	$20,190	$-	$146,261
Exploration costs	-	21,049	898,818
Development costs	25,382,377	5,075,710	24,931,571
	$25,402,567	$5,096,759	$25,976,650

Estimated Quantities of Proved Oil, NGL and Natural Gas Reserves

The following unaudited information regarding the Company’s oil, NGL and natural gas reserves is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geosciences 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 that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an

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Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, calculated the Company’s oil, NGL and natural gas reserves as of September 30, 2017, 2016 and 2015.

The Company’s net proved oil, NGL and natural gas reserves, which are located in the contiguous United States, as of September 30, 2017, 2016 and 2015, have been estimated by the Company’s Independent Consulting Petroleum Engineering Firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

All of the reserve estimates are reviewed and approved by our Vice President of Operations, Freda Webb, who reports directly to our President and CEO. Ms. Webb holds a Bachelor of Science Degree in Mechanical Engineering from the University of Oklahoma, a Master of Science Degree in Petroleum Engineering from the University of Southern California and a Professional Engineering License in Petroleum Engineering in the State of Oklahoma. Ms. Webb has more than 35 years of experience in the oil and gas industry. Before joining the Company, she was sole proprietor of a consulting petroleum engineering firm and a mineral acquisition company. Ms. Webb held various positions of increasing responsibility at

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Southwestern Energy Company and Occidental Petroleum Corporation, with reservoir engineering assignments in several field locations across the United States. She is an active member of the Society of Petroleum Engineers (SPE).

Our Vice President of Operations and internal staff work closely with our Independent Consulting Petroleum Engineers to ensure the integrity, accuracy and timeliness of data furnished to them for their reserves estimation process. We provide historical information (such as ownership interest, oil and gas production, well test data, commodity prices, operating costs and handling fees, and development costs) for all properties to our Independent Consulting Petroleum Engineers. Throughout the year, our team meets regularly with representatives of our Independent Consulting Petroleum Engineers to review properties and discuss methods and assumptions.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data was available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Net quantities of proved, developed and undeveloped oil, NGL and natural gas reserves are summarized as follows:

	Proved Reserves			
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total Bcfe
September 30, 2014	7,569,579	3,040,181	142,492,360	206.2
Revisions of previous estimates	(1,697,309)	(425,300)	(31,273,207)	(44.0)
Acquisitions (divestitures)	-	-	-	-
Extensions, discoveries and other additions	1,619,285	516,679	18,740,114	31.6
Production	(453,125)	(210,960)	(9,745,223)	(13.7)
September 30, 2015	7,038,430	2,920,600	120,214,044	180.0
Revisions of previous estimates	(1,552,010)	(1,192,143)	(47,068,144)	(63.5)
Acquisitions (divestitures)	-	-	-	-
Extensions, discoveries and other additions	303,922	65,306	16,864,075	19.1
Production	(364,252)	(171,060)	(8,284,377)	(11.5)
September 30, 2016	5,426,090	1,622,703	81,725,598	124.0
Revisions of previous estimates	253,481	407,250	13,651,501	17.6
Acquisitions (divestitures)	(37,724)	(12,953)	(669,064)	(1.0)
Extensions, discoveries and other additions	178,497	541,557	34,681,614	39.0
Production	(310,677)	(173,858)	(8,194,529)	(11.1)
September 30, 2017	5,509,667	2,384,699	121,195,120	168.6

The prices used to calculate reserves and future cash flows from reserves for oil, NGL and natural gas, respectively, were as follows: September 30, 2017 - $46.31/Bbl, $17.55/Bbl, $2.81/Mcf; September 30, 2016 - $36.77/Bbl, $12.22/Bbl, $1.97/Mcf; September 30, 2015 - $55.27/Bbl, $19.10/Bbl, $2.84/Mcf.

The revisions of previous estimates from 2016 to 2017 were primarily the result of:

- Positive pricing revisions of 17.9 Bcfe, resulting from the extension of projected economic limits than projected in 2016: proved developed revisions of 17.3 Bcfe and PUD revisions of 0.6 Bcfe.
- Negative performance revisions of 0.3 Bcfe.

The divestiture of 1.0 Bcfe in marginal properties located in southwestern Oklahoma.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Extensions, discoveries and other additions from 2016 to 2017 are principally attributable to:

- Proved developed reserve extensions, discoveries and other additions of 9.9 Bcfe principally resulting from the Company's participation in six wells in the liquids rich portion of the Anadarko Woodford Shale in Canadian County, Oklahoma.
- The addition of 29.1 Bcfe of PUD reserves, all are within the Company's active drilling program areas of the Anadarko Woodford Shale (Cana, STACK and SCOOP) and southeastern Oklahoma Woodford.

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)
September 30, 2015	2,725,077	1,466,834	82,899,159	4,313,353	1,453,766	37,314,885
September 30, 2016	1,980,519	1,095,256	62,929,047	3,445,571	527,447	18,796,551
September 30, 2017	2,201,528	1,768,425	87,861,043	3,308,139	616,274	33,334,077

The following details the changes in proved undeveloped reserves for 2017 (Mcfe):

Beginning proved undeveloped reserves	42,634,659
Proved undeveloped reserves transferred to proved developed	(15,670,848)
Revisions	819,338
Extensions and discoveries	29,097,406
Purchases	-
Ending proved undeveloped reserves	56,880,555

Beginning PUD reserves were 42.6 Bcfe. A total of 15.7 Bcfe (37% of the beginning balance) was transferred to proved developed producing during 2017. The 0.8 Bcfe (2% of the beginning balance) of positive revisions to PUD reserves were pricing revisions of 0.6 Bcfe and performance revision of 0.2 Bcfe. No PUD locations from 2013 remain in the PUD category. We anticipate that all the Company's PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves, which are no longer projected to be drilled within five years from the date they were added to PUD reserves, will be removed as revisions at the time that determination is made. In the event that there are undrilled PUD locations at the end of the five-year period, it is our intent to remove the reserves associated with those locations from our proved reserves as revisions. The Company added 29.1 Bcfe of PUD reserves in 2017 within the Company's active drilling program areas of the Anadarko Woodford Shale (Cana, STACK, SCOOP) and southeastern Oklahoma Woodford Shale.

Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards prescribe guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs to the estimated quantities of oil, NGL and natural gas to be produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced, based on continuation of the economic conditions applied for such year.

Estimated future income taxes are computed using current statutory income tax rates, including consideration for the current tax basis of the properties and related carry forwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates affect the valuation process.

	2017	2016	2015
Future cash inflows	$637,509,599	$380,263,695	$786,295,155
Future production costs	(256,193,675)	(182,948,045)	(311,933,151)
Future development and asset retirement costs	(93,133,683)	(72,431,842)	(124,857,957)
Future income tax expense	(102,193,819)	(38,674,100)	(123,007,909)
Future net cash flows	185,988,422	86,209,708	226,496,138
10% annual discount	(105,155,847)	(56,439,589)	(144,904,927)
Standardized measure of discounted future net cash flows	$80,832,575	$29,770,119	$81,591,211

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Panhandle Oil and Gas Inc.

Notes to Financial Statements (continued)

Changes in the standardized measure of discounted future net cash flows are as follows:

	2017	2016	2015
Beginning of year	$29,770,119	$81,591,211	$204,782,504
Changes resulting from:			
Sales of oil, NGL and natural gas, net of production costs	(25,783,055)	(16,749,632)	(35,359,204)
Net change in sales prices and production costs	37,186,619	(86,198,778)	(211,336,729)
Net change in future development and asset retirement costs	(7,939,156)	21,636,258	9,569,985
Extensions and discoveries	38,582,908	11,640,704	34,327,400
Revisions of quantity estimates	15,282,587	(41,716,689)	(51,375,950)
Acquisitions (divestitures) of reserves-in-place	(962,667)	-	-
Accretion of discount	4,789,294	14,424,032	37,000,855
Net change in income taxes	(27,070,430)	44,533,277	102,592,290
Change in timing and other, net	16,976,356	609,736	(8,609,940)
Net change	51,062,456	(51,821,092)	(123,191,293)
End of year	$80,832,575	$29,770,119	$81,591,211

12. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a summary of the Company's unaudited quarterly results of operations.

	Fiscal 2017 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$7,036,643	$13,964,288	$12,437,186	$12,896,932
Income (loss) before provision for income taxes	$(3,345,392)	$4,273,433	$1,827,758	$1,465,134
Net income (loss)	$(2,238,392)	$3,470,433	$1,260,758	$1,039,134
Earnings (loss) per share	$(0.13)	$0.21	$0.07	$0.06

	Fiscal 2016 Quarter Ended			
	December 31	March 31	June 30	September 30

Revenues	$11,445,856	$7,592,852	$9,864,090	$10,157,985
Income (loss) before provision for income taxes	$(5,167,118)	$(12,013,161)	$(1,730,795)	$913,190
Net income (loss)	$(2,799,118)	$(7,438,161)	$(786,795)	$737,190
Earnings (loss) per share	$(0.17)	$(0.44)	$(0.05)	$0.05

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

None

ITEM 9A CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company maintains “disclosure controls and procedures,” as such term is defined in Rule 13a-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/CEO and Vice President/CFO, 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.

(b) MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company’s management is responsible for establishing and maintaining adequate “internal control over financial reporting,” as such term is defined in Exchange Act Rule 13a-15(f). The Company’s management, including the President/CEO and Vice President/CFO, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the Company’s management concluded that its internal control over financial reporting was effective as of September 30, 2017.

(c) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

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 ended September 30, 2017, or subsequent to the date the assessment was completed.

ITEM 9B OTHER INFORMATION

None

PART III

The information called for by Part III of Form 10-K (Item 10 – Directors and Executive Officers of the Registrant, Item 11 – Executive Compensation, Item 12 – Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13 – Certain Relationships and Related Transactions, and Item 14 – Principal Accountant Fees and Services), is incorporated by reference from the Company's definitive proxy statement, which will be filed with the SEC within 120 days after the end of the fiscal year to which this report relates.

PART IV

ITEM 15 EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K
FINANCIAL STATEMENT SCHEDULES

The Company has omitted all schedules because the conditions requiring their filing do not exist or because the required information appears in the Company's Financial Statements, including the notes to those statements.

EXHIBITS

(3)	Amended Certificate of Incorporation (incorporated by reference to Exhibit attached to Form 10 filed January 27, 1980, and to Forms 8-K dated June 1, 1982, December 3, 1982, to Form 10-QSB dated March 31, 1999, and to Form 10-Q dated March 31, 2007)
	By-Laws as amended (incorporated by reference to Forms 8-K dated October 31, 1994, February 24, 2006, October 29, 2008, August 2, 2011, December 11, 2013, and January 19, 2017)
(4)	Instruments defining the rights of security holders (incorporated by reference to Certificate of Incorporation and By-Laws listed above)
*(10.1)	Agreement indemnifying directors and officers (incorporated by reference to Form 10-K dated September 30, 1989, and Form 8-K dated June 15, 2007)
*(10.2)	Agreements to provide certain severance payments and benefits to executive officers should a Change-in-Control occur as defined by the agreements (incorporated by reference to Form 8-K dated September 4, 2007)
(10.3)	Amended and Restated Credit Agreement dated November 25, 2013 (incorporated by reference to Form 10-K dated December 11, 2013)
(10.4)	Second Amendment to Amended and Restated Credit Agreement and Joinder dated June 17, 2014 (incorporated by reference to Form 8-K dated June 19, 2014)
(10.5)	Third Amendment to Amended and Restated Credit Agreement and Joinder dated December 8, 2016
(10.6)	Fourth Amendment to Amended and Restated Credit Agreement and Joinder dated October 25, 2017 (incorporated by reference to Form 8-K dated October 26, 2017)
(12.1)	Statement of Computation of Ratio of Earnings to Fixed Charges
(23.1)	Consent of Ernst & Young, LLP
(23.2)	Consent of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(31.1)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(31.2)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32.1)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(93)	

(32.2)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(99)	Report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(101.INS)	XBRL Instance Document
(101.SCH)	XBRL Taxonomy Extension Schema Document
(101.CAL)	XBRL Taxonomy Extension Calculation Linkbase Document
(101.LAB)	XBRL Taxonomy Extension Labels Linkbase Document
(101.PRE)	XBRL Taxonomy Extension Presentation Linkbase Document
(101.DEF)	XBRL Taxonomy Extension Definition Linkbase Document

* Indicates management contract or compensatory plan or arrangement

REPORTS ON FORM 8-K

Form 8-K dated October 26, 2017; item 1.01 – Enter Into a Material Definitive Agreement

Form 8-K dated November 6, 2017; item 8.01 – Other Events

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

PANHANDLE OIL AND GAS INC.

By: /s/ Paul F. Blanchard Jr.
Paul F. Blanchard Jr.
Chief Executive Officer

Date: December 12, 2017

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Paul F. Blanchard Jr.	President, Chief Executive Officer, Director	December 12, 2017
Paul F. Blanchard Jr.		
/s/Robb P. Winfield	Vice President, Chief Financial Officer and Controller	December 12, 2017
Robb P. Winfield		
/s/ Mark T. Behrman	Director	December 12, 2017
Mark T. Behrman		
/s/ Lee M. Canaan	Director	December 12, 2017
Lee M. Canaan		
/s/ Robert O. Lorenz	Lead Independent Director	December 12, 2017
Robert O. Lorenz		
/s/ Robert E. Robotti	Director	December 12, 2017
Robert E. Robotti		
/s/ Darryl G. Smette	Director	December 12, 2017
Darryl G. Smette		
/s/ Chad L. Stephens III	Director	December 12, 2017
Chad L. Stephens III		
/s/ H. Grant Swartzwelder	Director	December 12, 2017
H. Grant Swartzwelder		