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, 2019

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:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, $0.01666 par value	PHX	New York Stock Exchange

Securities registered under Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities 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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). _X_ Yes __ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the 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 $15.70 per share closing price of registrant's Class A Common Stock, as reported by the New York Stock Exchange at March 31, 2019, was $246,376,520.

As of December 1, 2019, the Registrant had 16,339,255 shares of Class A Common Stock outstanding.

Documents Incorporated By Reference

Portions of the definitive Proxy Statement of Panhandle Oil and Gas Inc. (to be filed no later than 120 days after September 30, 2019) relating to the Annual Meeting of Stockholders to be held on March 3, 2020, are incorporated into Part III of this Form 10-K.

TABLE OF CONTENTS

Special Note Regarding Forward Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act"), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-K by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements. Forward-looking statements may include, but are not limited to statements relating to: our ability to execute our business strategies; the volatility of realized oil and natural gas prices; the level of production on our properties; estimates of quantities of oil, NGL and natural gas reserves and their values; general economic or industry conditions; legislation or regulatory requirements; conditions of the securities markets; our ability to raise capital; changes in accounting principles, policies or guidelines; financial or political instability; acts of war or terrorism; title defects in the properties in which we invest; and other economic, competitive, governmental, regulatory or technical factors affecting our properties, operations or prices.

We caution you that the forward-looking statements contained in this Form 10-K are subject to risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K for the year ended September 30, 2019 (the "2019 Annual Report on Form 10-K" or this "Annual Report"), and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or elsewhere in our 2019 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except required by applicable law.

Except as required by applicable law, all forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Glossary of Certain Terms

The following is a glossary of certain accounting, oil and natural gas industry and other defined terms used in this Annual 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	the board of directors of the Company.
BTU	British Thermal Units.
Common Stock	the Company's Class A Common Stock.
completion	the post-drilling processes of preparing a well 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.
EBITDA	earnings before interest, taxes, depreciation and amortization (including impairment). This is a Non-GAAP measure.
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.
GAAP	generally accepted accounting principles.

gross acres or gross wells	the total acres or wells in which an interest is owned.
held by production or HBP	an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.
horizontal drilling	a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.
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.
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.
Mcfed	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 per day.
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 interests owned in gross acres or gross wells.
NGL	natural gas liquids.
NRI	net revenue interest.
NYMEX	the New York Mercantile Exchange.
OPEC	Organization of Petroleum Exporting Countries.
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.
WTI	West Texas Intermediate.

As used herein, the “Company,” “Panhandle,” “we,” “us” and “our” refer to Panhandle Oil and Gas Inc. and its predecessors and subsidiaries unless the context requires otherwise.

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 2019 mean the fiscal year ended September 30, 2019.

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

Overview

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.

Panhandle Oil and Gas Inc. is an Oklahoma City-based company focused on perpetual oil and natural gas mineral ownership in resource plays in the United States. In addition, as part of our evolution as a company, we own interests in leasehold acreage and non-operated interests in oil and natural gas properties. Historically, we have participated with a working interest on some of our mineral and leasehold acreage.

Strategic Focus on Mineral Ownership

During fiscal 2019, the Company made the strategic decision to focus on perpetual oil and natural gas mineral ownership and growth through mineral acquisitions and the development of its significant mineral acreage inventory in its core areas of focus. In accordance with this strategy, the Company plans to cease taking any working interest positions on its mineral and leasehold acreage going forward. The Company believes that its strategy to focus on mineral ownership is the best path to giving our stockholders the greatest risk-weighted returns on their investments going forward.

A "mineral fee" is an interest in real property in which the owner owns all of the rights to the minerals under the surface forever, as compared to a mineral lease in which the lessee's rights end at the expiration of the lease term or after there is no longer production on the lease. Generally, the mineral interest owner of a mineral fee interest reserves a non-cost bearing royalty interest upon the lease of such oil, gas, and other minerals to an oil and gas exploration and development company. Such companies will lease such mineral interest from the fee mineral owner for a term with the expectation of producing oil and gas, thereby generating free cash flow from bonuses and royalties. As referenced above, Panhandle's leasehold interests are non-operated working interests on the lease of the minerals from the mineral fee owner. These non-operated working interests require Panhandle to contribute its proportionate share of the costs incurred by the operator in the development of such minerals. As discussed above and further below, Panhandle no longer expects to participate with such working interests going forward. Panhandle's mineral and leasehold properties are located primarily in Oklahoma, North Dakota, Texas, Arkansas and New Mexico. The majority of our oil, NGL and natural gas production is from wells located in Oklahoma, North Dakota, Texas and Arkansas.

Although a significant amount of our revenues is currently derived from the production and sale of oil, NGL and natural gas on our working interests, a growing portion of our revenues is derived from royalties granted from the production and sale of oil, NGL and natural gas. 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.

We owned approximately 258,231 perpetual mineral acres as of September 30, 2019, as detailed in the table below:

Play	Net Acres	% Producing	% Leased But Not Producing	% Unleased
SCOOP/STACK	11,171	62%	13%	25%
Bakken/Three Forks	3,095	90%	0%	10%
Arkoma Stack	11,592	64%	2%	34%
Permian	39,275	10%	14%	76%
Fayetteville	9,903	72%	0%	28%
Eagle Ford	-	0%	0%	0%
Other	183,195	18%	3%	79%
Total:	**258,231**	**24%**	**5%**	**71%**

Approximately 71% of our net mineral position is currently unleased, providing us the opportunity to generate additional cash flow from bonus payments and royalties without spending additional capital. We also own leases on 17,199 net acres primarily in Oklahoma and working interests, royalty interests or both, in 6,496 producing oil and natural gas wells and 120 wells in the process of being drilled or completed.

Exploration and development of our oil and natural gas properties are conducted by oil and natural gas exploration and production companies, primarily larger independent operating companies. We do not operate any of our oil and natural gas properties. While we previously have been an active working interest participant for many years in wells drilled on the Company's mineral and leasehold acreage, our current focus is on growth through mineral acquisitions and through development of our significant mineral acreage inventory in our core areas of focus.

We intend to maximize value to our stockholders through the acquisition of mineral acreage, in the cores of resource plays, with substantial undeveloped opportunities; divestiture of non-core minerals with limited optionality when the amount negotiated exceeds our projected total value; and aggressive leasing of our mineral holdings.

Our Business Strategy

Our principal business objective is to maximize value to our stockholders. At the end of 2019, the Company made the strategic decision to cease taking any working interest positions on its mineral and leasehold acreage going forward. The Company has decided to focus on growth through mineral acquisitions and through development of its significant mineral acreage inventory in its core areas of focus. The Company believes that this is the best path to giving our stockholders the greatest risk-weighted returns on their investments going forward. We intend to accomplish this objective by executing the following corporate strategies:

- ***Manage Mineral and Leasehold Assets as a Portfolio to Maximize Value.*** We plan to manage our mineral and leasehold assets through the following:

- Growing our mineral fee holdings by acquiring mineral acreage, in the cores of oil and liquids-rich resource plays, with substantial undeveloped opportunities that meet or exceed our corporate return threshold;
- Aggressively leasing our mineral holdings;
- Selectively divesting non-core minerals with limited optionality when the amount negotiated exceeds our projected total value; and
- Optimizing our leasehold and working interest positions through strategic sales and farmouts for overriding royalty interests or cash payments.

- ***Maintain Strong Financial Position.*** We plan to maintain our strong financial position through the following:
  - Allocating capital for highest stockholder returns;
  - Utilize in-house technology and engineering expertise as a competitive advantage;
  - Maintaining conservative leverage ratio to ensure the ability to survive and thrive in all business and commodity cycles; and
  - Hedging to manage commodity risk and to protect our balance sheet.

Our Business Strengths

We believe the following attributes position Panhandle to achieve its objectives:

- ***Focused on Perpetual Mineral Fee Ownership.*** Our strategic decision to focus on mineral ownership provides us with the perpetual option to benefit from future development and technology. We are focused on generating meaningful revenues through lease bonuses and royalty interests and these revenues have been a growing proportion of our total revenues when compared to our working interests. We owned approximately 258,231 net mineral acres as of September 30, 2019, held principally in Oklahoma, North Dakota, Texas, Arkansas and New Mexico. We also held leases on 17,199 net acres primarily in Oklahoma; and working interests, royalty interests, or both, in 6,496 producing oil and natural gas wells and 120 wells in the process of being drilled or completed.

- ***Mineral and Leasehold Ownership in Multiple Top-Tier Resource Plays.*** We own mineral and leasehold interests in multiple top-tier resource plays in the United States, including positions in the SCOOP/STACK, Bakken/Three Forks, Arkoma Woodford, Eagle Ford, Permian Basin and Fayetteville plays. A significant portion of our revenues is derived from the production and sale of oil, NGL and natural gas from these positions. During the fiscal year ended September 30, 2019, production on our acreage was 28,382 Mcfed with approximately 19%, 13% and 68% being derived from oil, NGL and natural gas, respectively.

- ***Material Undeveloped Mineral Position in Oil and Gas Producing Basins.*** Over 70% of our mineral fee position is currently not leased or in production, providing us with significant value and the opportunity to generate additional cash flows from bonus payments and royalties without deploying additional capital. We have an active program in place focused on leasing open acreage to generate additional lease bonus revenue and future royalty revenue.

- ***Strong and Flexible Financial Position.*** We maintain a strong and flexible financial position through the management of our debt, cash and working capital. We evaluate our position, and we hedge to manage commodity price risk and to protect our balance sheet.

- ***Experienced Management and Technical Team.*** We have a management and technical team with extensive experience in the oil and gas industry. Our management and technical team average over 20 years of industry experience in each applicable area of the Company, including accounting, land, geology, engineering and mergers and acquisitions.

Principal Products and Markets

The Company derives revenue through its bonus and royalty payments and from working interests on its mineral and leasehold acreage. The Company's principal products from the production associated with its non-operated interests, in order of revenue generated, are crude oil, natural gas and NGL. These products are generally sold by our well operators 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 Company's control, 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 may be 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 and protect its return on investments. 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 entered into by the Company.

Competitive Business Conditions

The oil and natural gas industry is highly competitive, particularly in the search for new fee mineral interests and oil, NGL and natural gas reserves. Many factors beyond its control affect Panhandle's competitive position. Some of these factors include: the quantity and price of foreign oil imports; domestic supply and deliverability 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"). Many companies have substantially greater resources than we have, and such companies may have more resources to evaluate, bid for and purchase more mineral fee, royalty and similar interests than our financial or human resources permit.

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, to lease or farmout its mineral or leasehold acreage while retaining a royalty interest and to acquire new mineral acreage. We believe this strategy allows the Company to compete effectively in a competitive mineral market; however, our ability to acquire additional mineral fee, royalty and similar interests in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Major Customers

The Company's oil, NGL and natural gas production is sold, in most cases, through our lessees or well operators to numerous different purchasers.

Regulation of the Oil and Natural Gas Industry

General

As the owner of mineral fee interests and non-operating working interests, we do not have any employees or contractors in the field and we are not directly subject to many of the regulations of the oil and gas industry. The following disclosure describes regulations and environmental matters more directly associated with operators of oil and natural gas properties, including our current operators. Since the Company does not operate any wells in which it owns an interest, actual compliance with many laws and regulations is controlled by the well operators, with Panhandle being responsible only for its proportionate share of the costs, if any, involved on wells in which it owns a working interest.

Oil and natural gas operations are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. Legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for potential revision. Some of these requirements carry substantial penalties for failure to comply.

Although we are generally not directly subject to many of the rules, regulations and limitations impacting the oil and natural gas exploration and production industry as whole, the operators who operate on our properties may be impacted by such rules and regulations and we may be responsible for our proportionate share of costs for wells on which we own a working interest. While this may provide the Company with some insulation from compliance costs applicable to our operator-lessees, we may still be indirectly impacted by operator regulations because our revenue stream depends on operators and the production of oil, NGL and natural gas.

Regulation of Drilling and Production

The production of oil and natural gas is subject to regulation under federal, state and local statutes, rules, orders and regulations. These statutes and regulations require that operators obtain permits for drilling operations and drilling bonds, as well as require reports concerning operations. Additionally, states where we own mineral and leasehold interests have enacted regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that can be produced from wells and to limit the number of wells or the locations at which can be drilled. Additionally, some states where we hold mineral or leasehold interests may impose a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction.

Regulation of Transportation of Oil

The sale and transportation of our crude oil is generally undertaken by the operators (or by third parties at the direction of the operators) of our properties. Sales of crude oil, condensate and NGL are not currently regulated and are made at negotiated prices; however, Congress could reenact price controls in the future.

Sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the “FERC”) regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines’ published tariffs.

Regulation of Transportation and Sale of Natural Gas

The sale and transportation of our natural gas is generally undertaken by the operators (or by third parties at the direction of the operators) of our properties. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the

Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

The FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state.

Environmental Compliance and Risks

Our operators and properties are impacted by extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment and relating to safety and health.

Oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Historically, most of the environmental regulation of oil and gas production has been left to state regulatory boards or agencies in those jurisdictions where there is significant oil and natural gas production, with limited direct regulation by such federal agencies as the Environmental Protection Agency. However, there are various regulations issued by the Environmental Protection Agency ("EPA") and other governmental agencies that would govern significant spills, blow-outs or uncontrolled emissions.

Many states, including states where we own properties have enacted oil and natural gas regulations that apply to the drilling, completion and operations of wells and the disposal of waste oil and salt water. The operators of our properties are subject to such regulations. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency.

At the federal level, among the more significant laws and regulations that may affect our business and the oil and natural gas industry are: The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as "CERCLA" or "Superfund; the Oil Pollution Act of 1990; the Resource Conservation and Recovery Act, also known as "RCRA,";

the Clean Air Act; Federal Water Pollution Control Act of 1972, or the Clean Water Act; and the Safe Drinking Water Act of 1974.

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 on wells that we own a working interest. As such, the Company has no knowledge of any instances of non-compliance with existing laws and regulations. The Company maintains insurance coverage at levels which are customary in the industry, but is not fully insured against all environmental risks.

Taxes

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

Employees

At September 30, 2019, Panhandle employed 22 persons. In addition to serving as the Interim Chief Executive Officer, Mr. Chad Stephens, also serves as a director of the Company.

Corporate Office

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

Available Information

We make available free of charge on our website (www.panhandleoilandgas.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC.

We also make available within the "Corporate Governance" section under the "Investors" section of our website our Code of Ethics & Business Practices, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines, Lead Independent Director Charter and Audit Committee, Corporate Governance and Nominating Committee and Compensation Committee Charters, which have been approved by our Board of Directors. We will make timely disclosure on our website of any change to, or waiver from, the Code of Ethics & Business Practices and Code of Ethics for Senior Financial Officers for our principal executive and senior financial officers. Copies of our Code of Ethics & Business Practices and Code of Ethics for Senior Financial Officers are available free of charge by writing us at: Panhandle Oil and Gas Inc., Attn: Robb Winfield, 5400 N. Grand Blvd., Suite 300, Oklahoma City, OK 73112.

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. As the owner of mineral fee interests and non-operating working interests, we do not operate any oil and natural gas properties, and we do not have any employees or contractors in the field. As such, the risks associated with oil and gas operations only affect us indirectly and typically through our non-operating working interests as we proportionately share in the costs of operating such wells. 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.

Risks Related to our Business

The volatility of oil and natural gas prices, and particularly the ongoing decline in those prices, due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

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 beyond our control, including:

- domestic and 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;
- 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;
- conservation and environmental protection efforts;

- 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; and
- technological advancements affecting energy consumption and energy supply.

Our revenues, operating results, cash available for distribution and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of oil and natural gas;
- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of the OPEC to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;

- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;

- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and

- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. If the prices of oil and natural gas remain at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be determined at the discretion of our lenders.

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

The volatility of the energy markets makes it extremely difficult to predict future oil, NGL and natural gas price movements with any certainty. Oil, NGL and natural gas prices continued to fluctuate in fiscal year 2019 and have fluctuated significantly over the past several months. 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 were 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 operators drill 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; and

- the Company may incur a reduction in the borrowing base on its credit facility.

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. The decision to not participate in future development on our leasehold acreage can trigger a test for impairment. 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, stockholders' 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 "Impairment."

Our future success depends on finding, developing or acquiring additional reserves and 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 the eventual 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; and
- expected sales price to be received for oil, NGL or natural gas produced from the wells.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently hold properties, which could result in unforeseen operating difficulties. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to effectively integrate the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition, results of operations and cash available for distribution. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth, results of operations and cash available for distribution.

Any acquisitions of additional mineral and royalty interests that we complete will be subject to substantial risks.

Even if we do make acquisitions that we believe will increase our cash generated from operations, these acquisitions may nevertheless result in a decrease in our cash distributions per share. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, operating expenses and costs;
- a decrease in our liquidity by using a significant portion of our cash generated from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and
- the occurrence of other significant changes, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges.

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 (DeGolyer and MacNaughton of Dallas, Texas) must make various assumptions with respect to many matters that may prove to be incorrect, including:

- future oil, NGL and natural gas prices;
- unexpected complications from offset well development;
- 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; and
- 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. Production and income tax expenses are deducted from this calculation of future estimated development, 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 records. 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 13 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data."

Since 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 the development and production on 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.

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

Historically, the Company funded 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; and
- 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.

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, 2019, the Company had a balance of $35,425,000 drawn on the facility. The facility has a current borrowing base of $70,000,000, 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;
- a significant increase in the interest rate on our credit facility will limit funds available for other purposes; and
- 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 might adversely affect our business, financial condition, results of operations and cash flows.

We may incur losses as a result of title defects in the properties we own.

Consistent with industry practice, we do not have current abstracts or title opinions on all of our mineral acreage and, therefore, cannot be certain that we have unencumbered title to all of these properties. Our failure to cure any title defects that may exist may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we may suffer a financial loss.

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 or grow production.

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. 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 with reputable operators in this highly competitive environment.

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

The oil and natural gas industry in general has become increasingly dependent upon digital technologies to conduct day-to-day operations, including certain exploration, development and production activities. We use digital technology to estimate quantities of oil, NGL and natural gas reserves, process and record financial data and communicate with our employees and third parties. 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. For instance, unauthorized access to our reserves information or other proprietary or commercially sensitive information could lead to data corruption, communication interruption or other disruptions in our operations or planned

business transactions, any of which could have a material adverse impact on our results of operations. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

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 currently, and may in the future, 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. In addition, this type of derivative contract can limit the benefit we would receive from increases in the prices for oil and natural gas. The fair value of our oil and natural gas derivative instruments outstanding as of September 30, 2019, was a net asset of $2,494,144.

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.

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

We are subject to U.S. federal income tax, as well as income or capital-based taxes in various states, and our operating cash flow is sensitive to the amount of income taxes we must pay. Income taxes are assessed on our revenue after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types of costs that are considered allowable deductions or the rates assessed on our taxable earnings would all impact our income taxes and resulting operating cash flow.

Congress passed legislation in December 2017, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Reform Legislation"), that significantly affects U.S. tax law. The Tax Reform Legislation contains a number of changes to the manner in which the U.S. imposes income tax on multinational corporations. Although some changes should be positive, such as a permanent reduction to the corporate income tax rate, the repeal of the corporate alternative minimum tax, a temporary increase in the amount of bonus depreciation available for qualified property placed into service between September 27, 2017, and December 31, 2022, and other changes may negatively affect the Company. These provisions include, for example, significant additional limitations on the deductibility of interest expense and net operating losses and the repeal of the domestic production activity deduction. In addition, compliance with the Tax Reform Legislation and ensuing regulations will require complex computations and accumulation of information not previously required or regularly produced.

Further revisions to U.S. tax law, such as a reversal of the corporate income tax rate reduction, the repeal of the percentage depletion allowance, the repeal of expensing for intangible drilling costs or the repeal of enhanced bonus depreciation, could have a materially adverse effect on our business. Moreover, the U.S. Department of Treasury has broad authority to issue regulations and interpretative guidance that may significantly impact how we apply U.S. tax law, with a corresponding impact on the results of our operations for the periods affected.

Oklahoma Taxation

Oklahoma imposes a gross production tax, or severance tax, on the value of oil, NGL and natural gas produced within the state. Under recent changes to Oklahoma law, the gross production tax rate on the first three years of a horizontal well's production was increased from 2.2% to 5.2%, effective July 1, 2018. This increase in tax will likely decrease the profitability of newer horizontal wells producing oil, NGL and natural gas in Oklahoma, including wells in which the Company owns an interest.

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 statewide 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 byproduct 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.

Legislation to regulate greenhouse gas emissions has periodically been introduced in the U.S. Congress and such legislation may be proposed in the future. In addition, 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, the President of the United States announced that the United States planned to withdraw from the Paris Agreement and to seek negotiations to either reenter the Paris Agreement on different terms or

establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement, or a separately negotiated agreement are unclear at this time.

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

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.

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 CFTC (the United States Commodity Futures Trading Commission) 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 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.

Risks Related to our Third-Party Operators

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 workover or recomplete 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; and
- 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 oil and natural gas drilling and producing operations of our third-party operators involve various risks.

Because we do not operate our properties, our business relies heavily upon our third-party operators and their operational effectiveness. Through our third-party operators, we are 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;
- 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; and
- regulatory compliance issues.

As a non-operator, we are also 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 might have a material adverse effect on the Company's business condition and financial results.

We may experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

A failure on the part of the operators to make royalty payments gives us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a proceeding under title 11 of the United States Code (the "Bankruptcy Code"), in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise impaired. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have a substantial period of time to decide whether to ultimately reject or assume the lease, which could prevent the execution of a new lease or the assignment of the existing lease to another operator. In the event that the operator rejected the lease, our ability to collect amounts owed would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, the replacement operator may not achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

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.

The marketability of oil and natural gas production is dependent upon transportation, pipelines and refining facilities, which neither we nor many of our operators' control. Any limitation in the availability of those facilities could interfere with our or our operators' ability to market our or our operators' production and could harm our business.

The marketability of our or our operators' production depends in part on the availability, proximity and capacity of pipelines, tanker trucks and other transportation methods and processing and refining facilities owned by third parties. The amount of oil that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of available capacity on these systems, tanker truck availability and extreme weather conditions. Also, the shipment of our or our operators' oil and natural gas on third-party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we or our operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation, processing or refining-facility capacity could reduce our or our operators' ability to market oil production and have a material adverse effect on our financial condition, results of operations and cash distributions to stockholders. Our or our operators' access to transportation options and the prices we or our operators receive can also be affected by federal and state regulation—including regulation of oil production, transportation and pipeline safety—as well by general economic conditions and changes in supply and demand. In addition, the third parties on whom we or our operators rely for transportation services are subject to complex federal, state, tribal and local laws that could adversely affect the cost, manner or feasibility of conducting our business.

Risks Related to the Oil and Gas Industry

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, financial condition and cash available for distribution.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit in the European, Asian and the U.S. markets contribute to

economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, NGL and natural gas, volatility in consumer confidence and job markets, may result in an economic slowdown or recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which oil, NGL and natural gas from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and cash available for distribution.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash available for distribution.

Risks Related to an Investment in our Common Stock

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 stockholders.

The Company 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 stockholders to sell shares of our common stock at prices they deem acceptable.

We are currently authorized to issue an aggregate of 24,000,000 shares of common stock of which 16,339,255 shares were issued and outstanding on December 1, 2019. Future issuances of our common stock, or other securities convertible into our common stock, may result in significant dilution to our existing stockholders. Significant dilution would reduce the proportionate ownership and voting power held by our existing stockholders.

We may reduce or suspend our dividend in the future.

We have paid a quarterly dividend for many years. Our most recent quarterly dividend was $0.04 per share, and we have paid the same quarterly dividend for the past two years. In the future, our Board may, without advance notice, determine to reduce or suspend our dividend in order to maintain our financial flexibility and best position the Company for long-term success. The declaration and amount of future dividends is at the discretion of our Board and will depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our Board deems relevant. The likelihood that dividends will be reduced or suspended is increased during periods of prolonged market weakness. In addition, our ability to pay dividends may be limited by agreements governing our indebtedness now or in the future. Although we do not currently have plans to reduce or suspend our dividend, there can be no assurance that we will not reduce our dividend or that we will continue to pay a dividend in the future.

ITEM 1B. Staff Comments

None

ITEM 2. Properties

General Background

Panhandle is focused on perpetual oil and natural gas mineral ownership in resource plays in the United States. As part of our evolution as a company, we also own interests in leasehold acreage and non-operated working interests in oil and natural gas properties.

At September 30, 2019, Panhandle's principal properties consisted of (i) perpetual ownership of 258,231 net mineral acres, held principally in Oklahoma, North Dakota, Texas, Arkansas and New Mexico; (ii) leases on 17,199 net acres primarily in Oklahoma; and (iii) working interests, royalty interests or both in 6,496 producing oil and natural gas wells and 120 wells in the process of being drilled or completed.

Management's Business Strategy Related to Properties

During fiscal 2019, the Company made the strategic decision to focus on perpetual oil and natural gas mineral ownership and growth through mineral acquisitions and the development of its significant mineral acreage inventory in its core areas of focus. In accordance with this strategy, we will no longer participate in new development on our mineral or leasehold acreage with a cost-bearing working interest. The Company believes that its strategy to focus on mineral ownership is the best path to giving the Company's stockholders the greatest risk-weighted returns on their investments going forward.

Our goal is to increase stockholder value through the management of our fee mineral and leasehold assets as a portfolio. We plan to grow our mineral fee holdings by acquiring mineral acreage, in the cores of resource plays with substantial undeveloped opportunities, that meets or exceeds our corporate return threshold. We also plan to aggressively lease our mineral holdings.

We have an active program in place focused on leasing open acreage to generate additional lease bonus revenue and future royalty revenue.

Title to Properties

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 its properties. In recent years, a few insignificant challenges have been made against the Company's fee title to its acreage.

Acreage

Mineral Interests Owned

The following table of mineral interests owned reflects, in each respective state, the number of (i) net and gross acres owned by the Company, (ii) net and gross producing acres owned by the Company, (iii) net and gross acres leased to others by the Company and (iv) net and gross acres open (unleased) as of September 30, 2019.

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	11,965	51,391	7,167	27,026	-	-	4,798	24,365
Colorado	8,217	39,081	-	-	8	80	8,209	39,001
Florida	3,665	7,878	-	-	-	-	3,665	7,878
Kansas	3,102	11,856	164	1,240	-	-	2,938	10,616
Montana	1,008	17,948	-	-	-	-	1,008	17,948
New Mexico	57,169	173,445	1,336	6,808	190	391	55,643	166,246
North Dakota	14,303	78,103	2,773	14,490	-	-	11,530	63,613
Oklahoma	114,377	960,315	43,889	349,495	7,625	50,313	62,863	560,507
South Dakota	1,825	9,300	-	-	-	-	1,825	9,300
Texas	42,408	355,978	5,269	53,265	5,567	42,162	31,572	260,551
Other	192	3,262	165	3,000	-	-	27	262
Total:	**258,231**	**1,708,557**	**60,763**	**455,324**	**13,390**	**92,946**	**184,078**	**1,160,287**

(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 the Company's net mineral acres leased from others, lease expiration dates, and net leased acres held by production as of September 30, 2019.

		Net Acres Expiring					
State	Net Acres	2020	2021	2022	2023	2024	Net Acres Held by Production
Arkansas	2,159	-	-	-	-	-	2,159
Oklahoma	11,608	-	-	-	-	-	11,608
Texas	2,349	-	-	-	-	-	2,349
Other	1,083	-	-	-	-	-	1,083
TOTAL	17,199	-	-	-	-	-	17,199

Proved Reserves

Summary of Proved Reserves

The following table summarizes estimates of proved reserves of oil, NGL and natural gas held by Panhandle as of September 30, 2019, compared to the two preceding year ends, using prices and costs under existing economic conditions. Proved reserves are located onshore within the contiguous United States and are principally made up of small interests in 6,496 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.

Summary of Proved Oil and Natural Gas Reserves

	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)	Total Proved (Mcfe)
Net Proved Developed Reserves				
September 30, 2019	1,863,096	1,747,242	67,713,193	89,375,221
September 30, 2018	2,334,587	2,085,706	83,151,954	109,673,712
September 30, 2017	2,201,528	1,768,425	87,861,043	111,680,761
Net Proved Undeveloped Reserves				
September 30, 2019	516,994	226,038	12,560,713	17,018,905
September 30, 2018	3,649,835	848,484	36,910,082	63,899,996
September 30, 2017	3,308,139	616,274	33,334,077	56,880,555
Net Total Proved Reserves				
September 30, 2019	2,380,090	1,973,280	80,273,906	106,394,126
September 30, 2018	5,984,422	2,934,190	120,062,036	173,573,708
September 30, 2017	5,509,667	2,384,699	121,195,120	168,561,316

Exploration and development of our oil and natural gas properties is conducted by oil and natural gas exploration and production companies, primarily larger independent operating companies. We do not operate any of our oil and natural gas properties.

For the year ended September 30, 2019, our net total proved reserves decreased by approximately 67.2 Bcfe, as compared to September 30, 2018. The decrease in total proved reserves from 2018 to 2019 is attributable to a combination of the following factors:

- Negative pricing revisions of 4.4 Bcfe (comprised of proved developed revisions of 4.3 Bcfe and PUD revisions of 0.1 Bcfe), which primarily resulted from oil and natural gas wells reaching their economic limits earlier than was projected in 2018 due to lower oil prices and higher natural gas price deducts in 2019 relative to 2018.

- Negative revisions of 56.2 Bcfe, which included (i) proved undeveloped negative revisions of 48.2 Bcfe, primarily resulting from the Company's implementation of its new strategy of focusing on perpetual mineral ownership and not participating with a working interest in future drilling programs, which resulted in the removal of undeveloped leasehold wells (including wells in the Eagle Ford Shale) and lowering the net revenue interest on previously planned working interest wells on our mineral acreage to a royalty revenue interest only and (ii) proved developed revisions of negative 8.0 Bcfe, principally due to lower performance of our high-interest Woodford natural gas wells drilled in 2017 in the Arkoma Stack and, to a lesser extent, lower performance of the Fayetteville Shale natural gas properties in Arkansas.

- Proved developed reserve extensions, discoveries and other additions of 2.1 Bcfe principally resulting from: (i) the Company's royalty interest ownership in the ongoing development of unconventional oil, NGL and natural gas utilizing extended horizontal drilling in the Woodford Shale in the STACK, SCOOP and Arkoma Stack in Oklahoma; (ii) the Company's royalty interest ownership in the ongoing development of unconventional oil, NGL and natural gas utilizing horizontal drilling in the STACK Meramec play in the Anadarko Basin in western Oklahoma; and (iii) the Company's royalty interest ownership in ongoing development of conventional and unconventional oil, NGL and natural gas utilizing horizontal drilling in the Permian Basin.

- The addition of 4.7 Bcfe of PUD reserves within the Company's active drilling program areas of (i) the STACK Meramec in western Oklahoma, (ii) the SCOOP Woodford Shale in western Oklahoma, (iii) the Woodford Shale in the Arkoma Stack in southeastern Oklahoma, (iv) the Marmaton in Ellis County, Oklahoma, and (v) the Yeso in Eddy County, New Mexico.

- The acquisition of 0.8 Bcfe, predominately in the active drilling program of the Bakken in North Dakota, of which 0.5 Bcfe were proved developed and 0.3 Bcfe were proved undeveloped.

- The sale of 3.8 Bcfe, predominately in the Permian Basin in Texas and New Mexico, of which 2.2 Bcfe were proved developed and 1.6 Bcfe were proved undeveloped.

- Production of 10.4 Bcfe from the Company's oil and natural gas properties.

Proved Undeveloped Reserves

The following details the changes in proved undeveloped reserves for 2019 (Mcfe):

Beginning proved undeveloped reserves	63,899,996
Proved undeveloped reserves transferred to proved developed	(1,763,402)
Revisions	(48,404,716)
Extensions and discoveries	4,679,986
Sales	(1,648,780)
Purchases	255,821
Ending proved undeveloped reserves	17,018,905

For the fiscal year ending September 30, 2019, our beginning PUD reserves were 63.9 Bcfe. In 2019, a total of 1.8 Bcfe (3% of the beginning balance) was transferred to proved developed. The 48.4 Bcfe (76% of the beginning balance) of negative revisions to PUD reserves were pricing revisions of 0.2 Bcfe and a revision of 48.2 Bcfe, predominately resulting from the removal of oil, NGL and natural gas reserves associated with our working interest in Eagle Ford wells and working interests in wells in the STACK, SCOOP and Arkoma Stack plays, consistent with the Company implementing the strategy to no longer participate with working interests moving forward.

We anticipate that all the Company's current 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 4.7 Bcfe of PUD reserves in 2019 within the active drilling program areas of (i) the SCOOP Woodford Shale in western Oklahoma, (ii) the Anadarko Basin STACK Meramec in western Oklahoma, (iii) the Marmaton in Ellis County, Oklahoma, (iv) the Arkoma Stack in eastern Oklahoma and (v) the Yeso in Eddy County, New Mexico. These additions result from continuing development and additional well performance data in each of the referenced plays. Additionally, the Company purchased 0.3 Bcfe in the Bakken play in North Dakota and sold 1.6 Bcfe, predominately in the Permian Basin in Texas and New Mexico.

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 each of the years 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, 2019, 2018 and 2017, were as follows: in 2019, $54.40/Bbl for oil, $19.30/Bbl for NGL and $2.48/Mcf for natural gas; in 2018, $62.86/Bbl for oil, $26.13/Bbl for NGL and $2.56/Mcf for natural gas; and in 2017, $46.31/Bbl for oil, $17.55/Bbl for NGL and $2.81/Mcf for natural gas. 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

	9/30/2019	9/30/2018	9/30/2017
Proved Developed	$161,943,514	$236,887,976	$ 206,878,778
Proved Undeveloped	48,900,497	174,078,883	81,303,463
Income Tax Expense	(47,788,416)	(95,872,182)	(102,193,819)
Total Proved	$163,055,595	$315,094,677	$ 185,988,422

10% Discounted Present Value of Estimated Future Net Cash Flows

	9/30/2019	9/30/2018	9/30/2017
Proved Developed	$ 86,814,212	$125,915,804	$ 112,276,166
Proved Undeveloped	23,581,427	78,657,354	13,746,585
Income Tax Expense	(24,834,110)	(48,247,304)	(45,190,176)
Total Proved	$ 85,561,529	$156,325,854	$ 80,832,575

Evaluation and Review of Reserves

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 13 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" for disclosures regarding our oil and natural gas reserves.

Under the SEC rules, 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, prepared the Company's oil, NGL and natural gas reserves estimates as of September 30, 2019, 2018 and 2017 (see Exhibits 23.2 and 99). Within DeGolyer and MacNaughton, the technical person primarily responsible for preparing the estimates set forth in the Report of DeGolyer and MacNaughton dated October 7, 2019, filed as Exhibit 99 to this Annual Report on Form 10-K, was Gregory K. Graves. Mr. Graves has a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin and is a Registered Professional Engineer in the state of Texas. He is a member or the Society of Petroleum Evaluation Engineers and has over 35 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Graves meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

All of the reserve estimates are reviewed and approved by our Vice President of Operations, Freda Webb. 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 36 years of experience in the oil and gas industry. 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, 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. 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, 2019, 2018 and 2017. Since the determination and valuation of proved reserves is a function of testing

and estimation, the reserves presented are expected to change as future information becomes available.

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 9/30/2019	Year Ended 9/30/2018	Year Ended 9/30/2017
Bbls - Oil	329,199	336,565	310,677
Bbls - NGL	216,259	255,176	173,858
Mcf - Natural Gas	7,086,761	8,721,262	8,194,529
Mcfe	10,359,509	12,271,708	11,101,739

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 9/30/2019	Year Ended 9/30/2018	Year Ended 9/30/2017
Per Bbl, Oil	$ 55.07	$ 61.75	$ 46.27
Per Bbl, NGL	$ 17.10	$ 23.14	$ 19.87
Per Mcf, Natural Gas	$ 2.48	$ 2.49	$ 2.70
Per Mcfe	$ 3.80	$ 3.94	$ 3.60

Average Production (lifting) Costs	Year Ended 9/30/2019	Year Ended 9/30/2018	Year Ended 9/30/2017
(Per Mcfe)			
Well Operating Costs (1)	$ 1.21	$ 1.10	$ 1.14
Production Taxes (2)	0.18	0.17	0.14
	$ 1.39	$ 1.27	$ 1.28

(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 2019, approximately 36% 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 field operating costs on those producing wells, but they do bear a share of the handling fees (primarily gathering and transportation).

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, 2019. 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	283	21.50	1,680	1,963
Natural Gas	1,476	55.75	3,057	4,533
Total	1,759	77.25	4,737	6,496

Panhandle's average interest in royalty interest only wells is 0.71%. Panhandle's average interest in working interest wells is 4.39% working interest and 4.27% 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, 2019, Panhandle owned 455,324 gross (60,763 net) developed mineral acres. Panhandle has also leased from others 186,077 gross (17,199 net) developed acres.

Undeveloped Acreage

As of September 30, 2019, Panhandle owned 1,253,233 gross and 197,468 net undeveloped mineral acres. All of our leases are held by production (or HBP), and we do not have any leases on undeveloped acres.

Drilling Activity

The following table sets forth Panhandle's 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, 2019	0.939636	0.395755	-
September 30, 2018	0.482972	0.994656	-
September 30, 2017	3.893043	0.456612	-
Exploratory Wells			
Fiscal years ended:			
September 30, 2019	-	-	-
September 30, 2018	-	-	-
September 30, 2017	0.001563	-	-
Purchased Wells			
Fiscal years ended:			
September 30, 2019	-	0.516293	-
September 30, 2018	-	1.566828	-
September 30, 2017	-	-	-

Present Activities

The following table sets forth the Company's gross and net oil and natural gas wells being drilled or waiting on completion as of September 30, 2019, in which Panhandle owns either a working interest, a royalty interest or both. These wells were not producing at September 30, 2019.

	Gross Working Interest Wells	Net Working Interest Wells	Gross Royalty Only Wells	Total Gross Wells
Oil	-	-	91	91
Natural Gas	1	0.0007	28	29

Other Facilities

The Company has an office lease on 12,369 square feet of office space in Oklahoma City, Oklahoma, which is scheduled to expire on April 30, 2020.

ITEM 3. Legal Proceedings

In the ordinary course of business, we may be, from time to time, a claimant or a defendant in various legal proceedings. There were no material pending legal proceedings involving the Company on September 30, 2019, 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

Market for our Common Stock

Our Common Stock is listed on the New York Stock Exchange (NYSE) under the trading symbol "PHX."

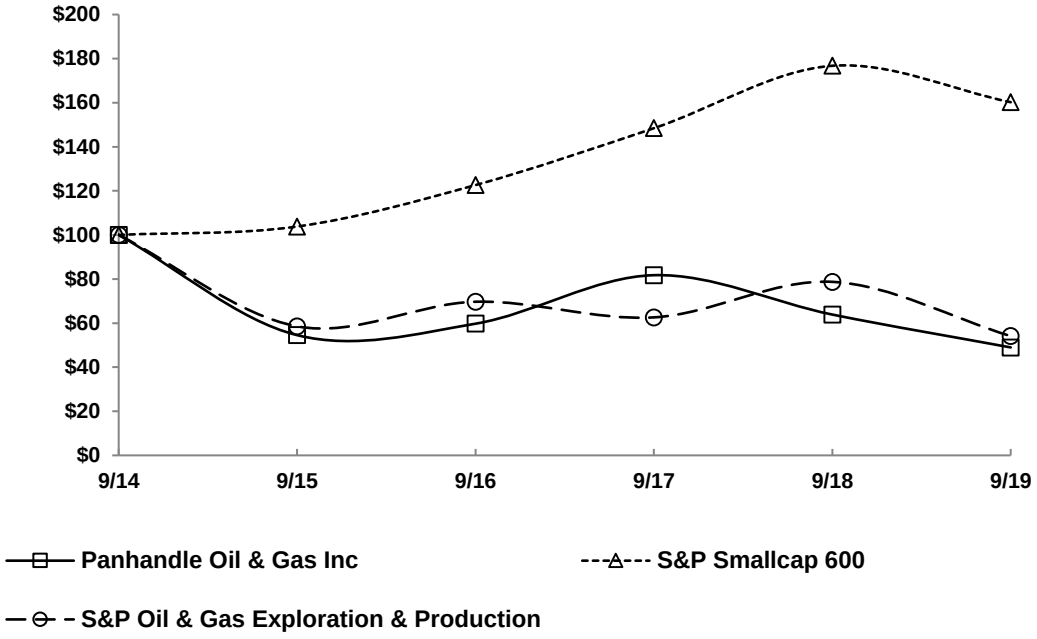
In March 2007, the Company increased its authorized Common Stock from 12 million shares to 24 million shares. On October 8, 2014, the Company split its Common Stock on a 2-for-1 basis in the form of a stock dividend. We currently have 24 million shares of Common Stock authorized.

Performance Graph

The following graph compares the 5-year cumulative total return provided stockholders on our 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, 2014, and the relative performance of such investment is tracked through and including September 30, 2019. This table is not intended to forecast future performance of our Common Stock.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN*

Among Panhandle Oil & Gas Inc, the S&P Smallcap 600 Index
and the S&P Oil & Gas Exploration & Production Index



*$100 invested on 9/30/14 in stock or index, including reinvestment of dividends.
Fiscal year ending September 30.

Record Holders

At December 1, 2019, there were 1,245 holders of record of our Common Stock and approximately 5,300 beneficial owners.

Dividends

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.

Historically, the Company has paid dividends to its stockholders on a quarterly basis. 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 loan agreement sets limits on dividend payments and stock repurchases if those payments would cause the leverage ratio to go above 2.75 to 1.0.

Purchases of Equity Securities by the Company

The following table presents information about repurchases of our Common Stock during the quarter ended September 30, 2019:

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 - 7/31/19	-	$ -	-	$ 215,942
8/1 - 8/31/19	40,581	$ 11.40	40,581	$ 1,253,210
9/1 - 9/30/19	42,858	$ 12.28	42,858	$ 727,128
Total	83,439	$ 11.85	83,439	

Following approval by the stockholders of the Company's 2010 Restricted Stock Plan in March 2010, as amended in May 2018, the Board approved the Company's repurchase program which, as amended, authorizes management to repurchase up to $1.5 million of the Company's Common Stock at its discretion. The repurchase program has an evergreen provision which authorizes the repurchase of an additional $1.5 million of the Company's Common Stock when the previous amount is utilized. As part of the amendment, the number of shares allowed to be purchased by the Company under the repurchase program is no longer capped at an amount equal to the aggregate number of shares of Common Stock (i) awarded pursuant to the Company's Amended 2010 Restricted Stock Plan, (ii) contributed by the Company to the Panhandle Oil and Gas Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan (the "ESOP") and (iii) credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

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,				
	2019	2018	2017	2016	2015
Revenues					
Oil, NGL and natural gas sales	$ 39,410,036	$ 48,385,335	$ 39,935,912	$ 31,411,353	$ 54,533,914
Lease bonuses and rentals	1,547,078	1,580,997	5,149,297	7,735,785	2,010,395
Gains (losses) on derivative contracts	6,105,145	(4,932,068)	1,249,840	(86,355)	13,822,506
Gain on asset sales	18,973,426	-	26,105	2,688,408	-
	66,035,685	45,034,264	46,361,154	41,749,191	70,366,815
Costs and expenses					
Lease operating expense	12,488,425	13,460,278	12,682,969	13,590,089	17,472,408
Production taxes	1,902,636	2,089,050	1,548,399	1,071,632	1,702,302
Depreciation, depletion and amortization	18,196,583	18,395,040	18,397,548	24,487,565	23,821,139
Provision for impairment	76,824,337	-	662,990	12,001,271	5,009,191
Interest expense	1,995,789	1,748,101	1,275,138	1,344,619	1,550,483
General and administrative	8,565,243	7,342,441	7,441,242	7,139,728	7,339,320
Loss on asset sales & other	288,610	102,685	131,935	112,171	(685,369)
	120,261,623	43,137,595	42,140,221	59,747,075	56,209,474
Income (loss) before provision (benefit) for income taxes	(54,225,938)	1,896,669	4,220,933	(17,997,884)	14,157,341
Provision (benefit) for income taxes	(13,481,000)	(12,739,000)	689,000	(7,711,000)	4,836,000
Net income (loss)	$ (40,744,938)	$ 14,635,669	$ 3,531,933	$ (10,286,884)	$ 9,321,341
Basic and diluted earnings (loss) per share	$ (2.43)	$ 0.86	$ 0.21	$ (0.61)	$ 0.56
Dividends declared per share	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Weighted average shares outstanding					
Basic and diluted	16,743,746	16,952,664	16,900,185	16,840,856	16,768,904
Net cash provided by (used in):					
Operating activities	$ 21,005,684	$ 26,943,894	$ 20,758,192	$ 22,639,151	$ 47,624,914
Investing activities	$ 10,325,211	$ (21,829,015)	$ (25,107,760)	$ 565,617	$ (31,642,385)
Financing activities	$ (25,702,706)	$ (5,140,168)	$ 4,436,146	$ (23,337,470)	$ (15,888,369)
Total assets	$ 126,644,947	$ 206,749,686	$ 206,744,219	$ 197,824,326	$ 238,825,273
Long-term debt	$ 35,425,000	$ 51,000,000	$ 52,222,000	$ 44,500,000	$ 65,000,000
Stockholders' equity	$ 79,309,533	$ 128,765,205	$ 116,707,539	$ 115,191,819	$ 127,004,675

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our accompanying financial statements and the notes to those financial statements included elsewhere in this Annual Report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements as a result of many factors, including those discussed under "Risk Factors" and elsewhere in this Annual Report.

Business Overview

We are focused on perpetual oil and natural gas mineral ownership in resource plays in the United States. In addition, as part of our evolution as a company, we own interests in leasehold acreage and non-operated interests in oil and natural gas properties. Historically, we have participated with a working interest on some of our mineral and leasehold acreage.

Our 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. Although a significant amount of our revenues is currently derived from the production and sale of oil, NGL and natural gas on our working interests, a growing portion of our revenues is derived from royalties granted from the production and sale of oil, NGL and natural gas.

Strategic Focus on Mineral Ownership

During fiscal 2019, the Company made the strategic decision to focus on perpetual oil and natural gas mineral ownership and growth through mineral acquisitions and the development of its significant mineral acreage inventory in its core areas of focus. In accordance with this decision, the Company plans to cease taking any working interest positions on its mineral and leasehold acreage going forward. As a result of the Company's strategic plan to focus on mineral ownership, the Company had a negative revision to its reserves, a significant provision for impairment and an increase in the DD&A rate in fiscal year 2019 from the Company's removal of all working interest PUDs from the year-end 2019 reserve report. The Company believes that its strategy to focus on mineral ownership is the best path to giving the Company's stockholders the greatest risk-weighted returns on their investments going forward.

Market Conditions and Commodity Prices

Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future commodity prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our production volumes or revenues.

Our working interest and royalty revenues may vary significantly from period to period as a result of changes in commodity prices, production mix and volumes of production sold by our operators.

Production and Operational Update

Our oil, NGL and natural gas production for the fiscal year ended September 30, 2019, decreased 2%, 15% and 19%, respectively, from that of 2018. The 2019 fiscal year's lower oil, NGL and natural gas prices (as discussed below) and the overall production changes noted above resulted in a 19% decrease in revenues from the sale of oil, NGL and natural gas in 2019.

The Company's proved oil, NGL and natural gas reserves decreased to 106.4 Bcfe in 2019, compared to 173.6 Bcfe in 2018, a decrease of approximately 67.2 Bcfe, or 39%. The decrease was primarily due to revisions slightly offset by additions, extensions and purchases. The revisions were due to the removal of oil, NGL and natural gas undeveloped reserves associated with working interest in Eagle Ford wells and working interest in wells in the STACK, SCOOP and Arkoma Stack plays consistent with the Company implementing a strategy to no longer participate with a working interest moving forward. This was coupled with negative performance revisions on developed reserves principally due to lower performance of high-interest Woodford natural gas wells drilled in 2017 in the Arkoma Stack and, to a lesser extent, lower performance of the Fayetteville Shale natural gas properties in Arkansas.

As of September 30, 2019, the Company owned an average 0.5% net revenue interest in 120 wells (primarily royalty interest) that were being drilled or awaiting completion.

Results of Operations

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

	For the Year Ended September 30,				
	2019	Percent Incr. or (Decr.)	2018	Percent Incr. or (Decr.)	2017
Production:					
Oil (Bbls)	329,199	(2%)	336,565	8%	310,677
NGL (Bbls)	216,259	(15%)	255,176	47%	173,858
Natural Gas (Mcf)	7,086,761	(19%)	8,721,262	6%	8,194,529
Mcfe	10,359,509	(16%)	12,271,708	11%	11,101,739
Average Sales Price:					
Oil (per Bbl)	$55.07	(11%)	$61.75	33%	$46.27
NGL (per Bbl)	$17.10	(26%)	$23.14	16%	$19.87
Natural Gas (per Mcf)	$2.48	(—%)	$2.49	(8%)	$2.70
Mcfe	$3.80	(4%)	$3.94	9%	$3.60

Production by quarter for 2019 and 2018 was as follows (Mcfe):

	2019	2018
First quarter	2,764,530	3,421,812
Second quarter	2,421,525	2,942,274
Third quarter	2,618,369	2,967,340
Fourth quarter	2,555,085	2,940,282
Total	10,359,509	12,271,708

Fiscal Year 2019 Compared to Fiscal Year 2018

Overview

Revenues increased in 2019 primarily due to gain on asset sales and gain on derivative contracts partially offset by lower oil, NGL and natural gas sales. Despite the increase in revenues, the Company recorded a net loss of $40,744,938, or $2.43 per share, in 2019, compared to net income of $14,635,669, or $0.86 per share, in 2018, as the result of a decrease in oil, NGL and natural gas sales and an increase in expenses in 2019. The increase in expenses in 2019 was primarily the result of increases in provision for impairment (non-cash) and increases in our G&A, partially offset by lower LOE, production taxes and DD&A.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales decreased $8,975,299, or 19%, for 2019, as compared to 2018. The decrease was due to decreased oil and NGL prices of 11% and 26%, respectively, combined with lower oil, NGL and natural gas volumes of 2%, 15% and 19%, respectively.

The decrease in oil production was a result of naturally declining production from the 2017 drilling program in the Eagle Ford and Anadarko Basin (STACK/SCOOP), offset by the 2018 seven-well drilling program in the Eagle Ford Shale that came online in March 2019 and mineral acquisitions of Bakken producing properties in late 2018 and during 2019. The NGL production decrease is attributed to natural production decline and operators electing to remove less NGL from the natural gas stream due to lower NGL prices. These decreases in the liquid-rich production from the prior year's drilling program in the Anadarko Basin (STACK/SCOOP plays) and Eagle Ford Shale were slightly offset by a mineral acquisition of producing properties in the Bakken. Decreased natural gas production was primarily due to naturally declining production in the Arkoma Stack and Anadarko Basin STACK and, to a lesser extent, the Fayetteville Shale.

In 2018, our total production significantly increased due to our substantial 2017 drilling program in the Arkoma Woodford (8 wells), Anadarko Woodford (6 wells) and Eagle Ford (10 wells) shales, which began production just before or during early 2018. All of these wells had significantly higher than average NRIs and were producing at high rates during that time. As with most horizontal wells, production from these wells experienced significant declines during their first year. Such declines in production, along with materially lower capital expenditures for drilling during fiscal 2018 and fiscal 2019, accounted for a significant portion of the Company's production decline experienced in 2019.

Given the Company's strategic decision to cease participating with working interests, we plan to offset the natural decline of our existing production base by the development of our current inventory of mineral acreage and through acquisitions of additional mineral interests going forward.

Gains (Losses) on Derivative Contracts

The fair value of derivative contracts was a net asset of $2,494,144 as of September 30, 2019, and a net liability of $3,414,016 as of September 30, 2018. We had a net gain on derivative contracts of $6,105,145 in 2019 as compared to a net loss of $4,932,068 in 2018. The change was principally due to the oil and natural gas collars and fixed price swaps being more beneficial in 2019, as NYMEX oil and natural gas futures experienced decreases in price in relation to the collars and the fixed prices of the swaps. Net cash received related to derivative contracts settled during 2019 was $196,985, compared to net cash paid of $1,001,893 in 2018.

The Company's oil and natural gas costless collar contracts and fixed price swaps in place at September 30, 2019, had expiration dates of December 2019 through December 2020. The Company utilizes derivative contracts for the purpose of protecting its cash flow and return on investments.

Gains on Asset Sales

Gain on asset sales was $18,973,426 in 2019, as a result of mineral and leasehold acreage sold by the Company. The Company sold mineral acreage in Lea and Eddy Counties, New Mexico, for a gain of $9,096,938; Martin County, Texas, (mineral and leasehold) for a gain of $4,921,656; Loving, Reeves and Ward Counties, Texas, for a gain of $2,704,323; and Reagan and Upton Counties, Texas, for a gain of $2,250,509. In 2018, the Company did not have a gain on asset sales.

Lease Operating Expenses (LOE)

LOE decreased $971,853 or 7% in 2019. LOE costs per Mcfe of production increased from $1.10 in 2018 to $1.21 in 2019. LOE related to field operating costs decreased $315,926 or 5% in 2019, compared to 2018. Field operating costs were $0.62 per Mcfe in 2019, compared to $0.55 per Mcfe in 2018. This increase in rate was principally the result of decreased production partially offset by the Company selling some non-core marginal properties which had higher operating costs.

The decrease in LOE related to field operating costs was coupled with a decrease in handling fees (primarily gathering, transportation and marketing costs) of $655,927 in 2019, primarily due to decreased production in 2019. On a per Mcfe basis, these handling fees were $0.59 in 2019 as compared to $0.55 in 2018. The increase in rate was primarily due to natural gas production (from wells with lower handling fees) declining from peak rates noted in 2018 and oil production (with lower handling fees) declining. 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 $186,414 or 9% in 2019, as compared to 2018. The decrease in amount was primarily the result of decreased oil, NGL and natural gas sales of $8,975,299 during 2019. Production taxes as a percentage of oil, NGL and natural gas sales increased from 4.3% in 2018 to 4.8% in 2019. The increase in tax rate was mainly due to a change in the Oklahoma production tax laws that took effect July 1, 2018. The discounted tax rate was increased from 2.2% to 5.2% for the first three years of production on horizontal wells. There was no change in the rate of 7.2% after the expiration of the discounted period. 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 horizontal wells, which are eligible for reduced Oklahoma production tax rates in the first few years of production.

Depreciation, Depletion and Amortization (DD&A)

DD&A decreased $198,457 in 2019. DD&A per Mcfe was $1.76 in 2019, compared to $1.50 in 2018. DD&A decreased $2,866,347 due to oil, NGL and natural gas production volumes decreasing 16% collectively in 2019, compared to 2018. This was mostly offset by an increase of $2,667,890 as the result of a $0.26 increase in the DD&A rate per Mcfe. The rate increase was principally due to the Company's strategic decision at the end of fiscal 2019 to cease participating with a working interest on its mineral and leasehold acreage and to focus solely on growth through mineral acquisitions going forward. Based on the Company's strategic decision to focus on mineral ownership, the Company removed all working interest PUDs from the year-end 2019 reserve report which caused the DD&A rate to temporarily spike in the fourth quarter of 2019 as these volumes could no longer be used in the calculation of DD&A on our leasehold positions. This impact was noted predominantly on our Eagle Ford assets (approximate increase from previous quarters was $1.5 million). Considering the impairment on the Eagle Ford assets (noted below), we expect our DD&A rate going forward to be significantly lower.

Provision for Impairment

Provision for impairment was $76,824,337 in 2019, as compared to no provision for impairment in 2018. During 2019, impairment of $76,560,376 was recorded on our Eagle Ford assets. The remaining $263,961 of impairment was recorded on other assets. The impairment on the Eagle Ford assets was caused by the Company's strategic decision to cease participating with a working interest on its mineral and leasehold acreage going forward and, therefore, removing all working interest PUDs from the reserve reports. The removal of the PUDs caused the asset to fail the step one test for impairment as its undiscounted cash flows were not high enough to cover the book basis of the assets. These assets were written down to their fair market value as required by GAAP. No impairment was recorded during 2018.

Interest Expense

Interest expense increased $247,688 in 2019, as compared to 2018. The increase was due to higher interest rates, partially offset by a lower outstanding debt balance during 2019.

General and Administrative Costs (G&A)

G&A increased $1,222,802 or 17% in 2019, as compared to 2018. The increase was primarily the result of higher personnel expenses. The increase in personnel expenses was primarily due to the severance of approximately $670,000 upon the resignation of our former CEO towards the end of fiscal 2019. We also had an increase in restricted stock expenses as a retirement clause in the restricted stock agreements required certain grants to become fully expensed during 2019. This was coupled with higher salary expenses due to other employee retirements and changes in personnel, as well as other compensation increases compared to 2018. Approximately $800,000 of the increased G&A expenses are attributable to nonrecurring expenses.

Provision (Benefit) for Income Taxes

Income tax benefit increased $742,000, from $12,739,000 in 2018 to $13,481,000 in 2019. In 2019, the benefit was the result of a large pretax loss from the impairment in the fourth quarter. During 2018, the benefit was mainly the result of the Tax Cuts and Jobs Act enacted in December 2017 that reduced the U.S. federal corporate tax rate from 35% to 21%. The tax effect of this law change on the existing deferred tax liabilities of $12,464,000 was made in 2018 and directly affected the effective tax rate noted for 2018. The effective tax rate changed from a 672% benefit in 2018 to a 25% benefit in 2019.

When a provision for income taxes is expected for the year, 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.

Fiscal Year 2018 Compared to Fiscal Year 2017

Overview

The Company recorded net income of $14,635,669, or $0.86 per share, in 2018, compared to net income of $3,531,933, or $0.21 per share, in 2017. Revenues decreased in 2018 primarily due to decreased lease bonuses received and losses on derivative contracts, largely offset by higher oil, NGL and natural gas sales.

Expenses increased in 2018 mainly from increases in LOE, production taxes and interest expenses partially offset by a lower provision for impairment.

Production by quarter for 2018 and 2017 was as follows (Mcfe):

	2018	2017
First quarter	3,421,812	2,517,414
Second quarter	2,942,274	2,351,207
Third quarter	2,967,340	2,953,915
Fourth quarter	2,940,282	3,279,203
Total	12,271,708	11,101,739

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales increased $8,449,423, or 21%, in 2018, as compared to 2017. The increase was due to increased oil and NGL prices of 33% and 16%, respectively, combined with higher oil, NGL and natural gas volumes of 8%, 47% and 6%, respectively, partially offset by decreased natural gas prices of 8% in 2018.

In the first quarter of 2018, we continued to see the results of our 2017 drilling program after four Eagle Ford wells were completed with first sales in November 2017. In the second quarter of 2018 we experienced the relatively steep early decline rates from new high working interest wells placed on production in the second half of 2017 and early 2018, as the wells stopped flowing efficiently due to loading. Volumes then leveled off with the installation of lift equipment on the new wells as they transitioned from flowing efficiently up the production casing to requiring downhole equipment modifications to resume efficient flow. Continued normal declines were then offset by first sales from drilling activity in the Anadarko Basin (STACK/SCOOP), southeastern Oklahoma and the Permian Basin.

The increase in oil production was primarily the result of new well drilling in the Eagle Ford Shale, Anadarko Basin (STACK/SCOOP) and Permian Basin, which was partially offset by declining production from the Bakken and various fields in western and northern Oklahoma and marginal/uneconomic property sales in northwestern Oklahoma.

An overall increase in NGL production was the result of six new wells in the Anadarko Basin STACK Woodford Shale and new well drilling in Anadarko Basin STACK Meramec, which was partially offset by the natural production decline of existing wells in various fields in western Oklahoma.

Natural gas production volume increases in 2018 were primarily the result of 2017 and 2018 drilling in western Oklahoma (STACK/SCOOP) and Arkoma Stack. The increase was partially offset by naturally declining production in the Fayetteville Shale and, to a much lesser extent, declining production from the Anadarko Basin Granite Wash and the non-core marginal/uneconomic property sales in northwestern Oklahoma and Kearny County, Kansas.

Lease Bonus and Rentals

Lease bonuses and rentals decreased $3,568,300 in 2018 from 2017. The decrease was mainly due to the Company leasing less valuable acreage in 2018 versus 2017. In 2018, the Company leased 1,754 net mineral acres in Oklahoma (mainly in Major, Ellis, and Roger Mills Counties), 415 net mineral acres in Texas (mainly in Dawson County) and 135 net mineral acres in New Mexico (mainly in Lea and Eddy Counties). 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).

Gains (Losses) on Derivative Contracts

The fair value of derivative contracts was a net liability of $3,414,016 as of September 30, 2018, and a net asset of $516,159 as of September 30, 2017. We had a net loss on

derivative contracts of $4,932,068 in 2018, as compared to a net gain of $1,249,840 in 2017. The change was principally due to the oil collars and fixed price swaps being less beneficial in 2018, as NYMEX oil futures experienced increases in price in relation to the collars and the fixed prices of the swaps. Net cash paid related to derivative contracts settled during 2018 was $1,001,893, compared to net cash received of $305,410 in 2017. As of September 30, 2018, the Company's oil and natural gas costless collar contracts and fixed price swaps had expiration dates of December 2018 through June 2020. The Company utilizes derivative contracts for the purpose of protecting its return on investments.

Lease Operating Expenses (LOE)

LOE increased $777,309 or 6% in 2018, compared to 2017. LOE costs per Mcfe of production decreased from $1.14 in 2017 to $1.10 in 2018. LOE related to field operating costs increased $225,954 or 3% in 2018, compared to 2017. Field operating costs were $0.55 per Mcfe in 2018, compared to $0.58 per Mcfe in 2017. This decrease in rate was principally the result of significant new low-cost production coming online in late 2017 and the Company selling certain wells with high operating costs in late 2017 and early 2018.

The increase in LOE related to field operating costs was coupled with an increase in handling fees (primarily gathering, transportation and marketing costs) of $551,355 in 2018, primarily due to increased production in 2018. On a per Mcfe basis, these handling fees were $0.55 in 2018, as compared to $0.56 in 2017. 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 $540,651 or 35% in 2018, as compared to 2017. The increase in amount was primarily the result of increased oil, NGL and natural gas sales of $8,449,423 during 2018. Production taxes as a percentage of oil, NGL and natural gas sales increased from 3.9% in 2017 to 4.3% in 2018. The increase in tax rate was mainly due to a change in the Oklahoma production tax laws that took effect July 1, 2018. The discounted tax rate was increased from 2.2% to 5.2% for the first three years of production on horizontal wells. There was no change in the rate of 7.2% after the expiration of the discounted period. 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 horizontal 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 $2,508 in 2018. DD&A per Mcfe was $1.50 in 2018, compared to $1.66 in 2017. DD&A decreased $1,941,354 as the result of a $0.16 decrease in the DD&A rate per Mcfe. This was primarily offset by an increase of $1,938,846 due to oil, NGL and natural gas production volumes increasing 11% collectively in 2018, compared to 2017. The rate decrease was principally due to higher oil and NGL prices utilized in the reserve calculations during 2018, as compared to 2017, lengthening the economic life of wells and, thus, resulting in higher projected remaining reserves on a significant number of wells. The Company had interests in

new high-volume wells with low finding costs begin producing in the later part of 2017 and early 2018, which also contributed to the rate decrease.

Provision for Impairment

No impairment was recorded during 2018. During 2017, impairment of $46,279 was recorded on five fields, primarily in Oklahoma and Texas and $616,711 of impairment was recorded on a group of wells that were held for sale at September 30, 2017.

Interest Expense

Interest expense increased $472,963 in 2018, as compared to 2017. The increase was due to higher interest rates and a higher outstanding debt balance during 2018.

Provision (Benefit) for Income Taxes

Income taxes changed $13,428,000, from a $689,000 provision in 2017 to a $12,739,000 benefit in 2018. This was mainly the result of the new Tax Cuts and Jobs Act enacted in December 2017 that reduced the U.S. federal corporate tax rate from 35% to 21%. The tax effects of this law change on our existing deferred tax liabilities of $12,464,000 was made in 2018 and directly affected the effective tax rate noted for 2018. Additionally, due to the Company having a September 30 year end versus a calendar year end, we calculated the 2018 federal tax provision using a blended rate of 24.53% to adjust for one quarter of our fiscal year being under the old rate of 35% and the remaining three quarters being under the new rate of 21%. The effective tax rate changed from a 16% provision in 2017 to a 672% benefit in 2018.

When a provision for income taxes is expected for the year, 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.

Liquidity and Capital Resources

At September 30, 2019, the Company had positive working capital of $11,378,829, as compared to positive working capital of $2,509,050 at September 30, 2018. The increase in working capital was primarily driven by increased cash from asset sales (like-kind exchanges), increased receivables from derivative contracts and refundable income taxes.

Liquidity

Cash and cash equivalents were $6,160,691 as of September 30, 2019, compared to $532,502 at September 30, 2018, an increase of $5,628,189. Cash flows for the 12 months ended September 30 are summarized as follows:

Net cash provided (used) by:

	2019	2018	Change
Operating activities	$ 21,005,684	$ 26,943,894	$ (5,938,210)
Investing activities	10,325,211	(21,829,015)	32,154,226
Financing activities	(25,702,706)	(5,140,168)	(20,562,538)
Increase (decrease) in cash and cash equivalents	$ 5,628,189	$ (25,289)	$ 5,653,478

Operating activities:

Net cash provided by operating activities decreased $5,938,210 during 2019, as compared to 2018, primarily the result of the following:

- Receipts of oil, NGL and natural gas sales (net of production taxes and gathering, transportation and marketing costs) and other decreased $6,366,441;
- Decreased income tax receipts of $336,061;
- Decreased net payments on derivative contracts of $1,198,878;
- Increased payments for interest expense of $301,301;
- Increased payments for G&A and other expense of $657,239; and
- Decreased field operating expenses of $522,530.

Investing activities:

Net cash provided by investing activities increased $32,154,226 during 2019, as compared to 2018, primarily as the result of the following:

- Lower drilling and completion activity during 2019 decreased our capital expenditures by $8,064,128;
- Lower acquisition activity decreased our expenditures by $5,664,502; and
- Higher proceeds received from the sale of assets of $18,430,598.

Financing activities:

Net cash used by financing activities increased $20,562,538 during 2019, as compared to 2018, primarily as a result of the following:

- Increased stock repurchases by the Company of $6,234,772 during 2019; and
- Increased net payments on long-term debt of $14,353,000.

Capital Resources

Capital expenditures to drill and complete wells decreased $8,064,128, or 70%, from the 2018 to the 2019 period. The Company made the strategic decision to focus on its mineral ownership and elected not to participate with a working interest on any mineral acreage proposals received during 2019; however, the Company did participate with a working interest in seven Eagle Ford wells at the end of 2018 and early 2019 (elections to participate were made prior to 2019). The outstanding capital commitment on those wells was minimal as of September 30, 2019.

At the end of 2019, the Company made the strategic decision to cease taking any working interest positions on its mineral or leasehold acreage going forward. The Company plans to focus on growth through mineral acquisitions and through development of its significant mineral acreage inventory in its core areas of focus. The Company believes that this is the best path to giving our stockholders the greatest risk-weighted returns on their investments going forward.

Since the Company has decided to cease any further participation in wells with a working interest on its mineral and leasehold acreage, we anticipate that capital expenditures for working interest properties to be minimal going forward, as the expenditures will be limited to capital workovers to enhance existing wells.

The Company plans to focus on growing the Company's assets through acquisitions of mineral acreage. We have a significant inventory of leased and unleased locations in the core of our major focus areas, which we believe will generate future revenue streams from bonus and royalty payments.

Net cash provided by our operating activities, as well as the sale of highly valued assets in the Permian Basin, funded all of the Company's capital expenditures, asset acquisitions, overhead costs, treasury stock purchases and dividend payments, while decreasing the Company's outstanding borrowings on the credit facility by $15.6 million and increasing our cash balance by $5.6 million during 2019. The Company received lease bonus payments during 2019 totaling approximately $1.6 million. Looking forward, the cash flow from bonus payments associated with the leasing of drilling rights on the Company's mineral acreage is difficult to project as the Company's mineral acreage position is diverse and spread across several states and oil and gas plays. However, management plans to continue to actively pursue leasing opportunities. The Company may also evaluate the sale of certain of the Company's mineral acres when valuations are greater than our internal estimates of present value are presented.

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 9/30/2019
Cash provided by operating activities	$ 21,005,684
Cash used for (provided by):	
Capital expenditures - acquisitions	5,662,869
Capital expenditures - drilling and completion of wells	3,526,007
Quarterly dividends of $0.04 per share	2,673,706
Treasury stock purchases	7,454,000
Net payments (borrowings) on credit facility	15,575,000
Proceeds from sales of assets	(19,515,735)
Other investing activities	1,648
Net cash used	15,377,495
Net increase (decrease) in cash	$ 5,628,189

Outstanding borrowings on our credit facility at September 30, 2019, were $35,425,000.

Looking forward, the Company intends to fund overhead costs, capital additions related to acquisitions 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 the Company's existing bank debt. The Company had availability of $34,575,000 under its revolving credit facility and was in compliance with its financial covenants at September 30, 2019.

The borrowing base under the credit facility was redetermined in August 2019 and changed to $70 million, which is a level that is expected to provide ample liquidity for the Company to continue to employ its normal operating strategies.

Our next scheduled borrowing base redetermination will occur later in December 2019. Given the current commodity pricing environment and our strategic decision to remove all working interest proved undeveloped reserves from our reserve report, we anticipate a reduction in our borrowing base from its current level of $70 million. We do not know the amount of reduction at this time, but we do not expect that it will impact the liquidity needed to maintain our normal operating strategies.

On November 6, 2017, the Company filed a shelf registration statement with the SEC on Form S-3 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.

Based on the Company's expected capital expenditure levels, anticipated cash provided by operating activities for 2020, combined with availability under its credit facility and shelf registration, 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 $70,000,000 and is secured by certain of the Company's properties with a carrying value of $74,435,747 at September 30, 2019. 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 0.50% to 1.25%, or 30-day LIBOR plus a range of 2.00% to 2.75% annually. At September 30, 2019, the effective rate was 4.34%. 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. The borrowing base under the credit facility was redetermined in August 2019 by the banks and reduced from $80 million to $70 million, which is a level that is expected to provide ample liquidity for the Company to continue to execute its operating strategies. 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 ratio (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, 2019, the Company was in compliance with the covenants of the loan agreement and had $34,575,000 of availability under its outstanding credit facility.

The table below summarizes the Company's contractual obligations and commitments as of September 30, 2019:

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	$35,425,000	$ -	$ -	$35,425,000	$ -
Building lease	$ 122,659	$122,659	$ -	$ -	$ -

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, 2019, the Company's derivative contracts were in a net asset position of $2,494,144. 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 Company's derivative contracts.

As of September 30, 2019, the Company's estimate for asset retirement obligations was $2,835,781. 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.

Off Balance Sheet Arrangements

Other than the lease of office space, the Company had no off balance sheet arrangements during 2019 or prior years.

We currently do not have any other off-balance sheet arrangement that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements in conformity with GAAP 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 include: crude oil, NGL and natural gas reserve estimation; derivative contracts; impairment of assets; oil, NGL and natural gas sales revenue accruals; and provision for income taxes. Management's judgments and estimates 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 13 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. The Company's Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares the Company's estimates of crude oil, NGL and natural gas reserves on an annual basis, with a semi-annual update. These estimates are 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 Company's 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 2019 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $1,819,658 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. 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 onshore in the continental United States and primarily located in the Mid-Continent area. Generally, expenditures on exploratory wells comprise less than 5% 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 costless collar contracts and 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. The Company's derivative contracts are with Bank of Oklahoma and Koch Supply and Trading LP. The derivative contracts with Bank of Oklahoma are secured under the credit facility with Bank of Oklahoma. The derivative contracts with Koch are unsecured.

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, 2019, 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. The decision to not participate in future development on our leasehold acreage can trigger a test for impairment. 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 no longer determined to 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, 2019, 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 GAAP. 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 2020 will impact the amount of cash generated from operating activities, which will in turn impact the level of the Company's capital expenditures for acquisitions and production. Excluding the impact of the Company's 2020 derivative contracts (see below), the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $708,676 for operating revenue based on the Company's prior year natural gas volumes. The price sensitivity in 2020 for each $1.00 per barrel change in wellhead oil is approximately $329,199 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 oil and natural gas prices. The Company does not enter into these derivatives for speculative or trading purposes. All of our outstanding derivative contracts at September 30, 2019, are with Bank of Oklahoma and Koch Supply and Trading LP. The derivative contracts with Bank of Oklahoma are secured under the credit facility with Bank of Oklahoma. The derivative contracts with Koch are unsecured. 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 $276,000. 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 $120,000. For the Company's oil collars, a change of $1.00 (below or above the collar) in the NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $79,000. See Note 1 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding our derivative contracts.

Interest Rate 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 0.50% to 1.25%, or 30-day LIBOR plus from 2.00% to 2.75%. At September 30, 2019, the Company had $35,425,000 outstanding under this facility and the effective interest rate was 4.34%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $354,250 for the year ended September 30, 2019, assuming that our indebtedness remained constant throughout the period. 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 significantly impacted in the near future.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Annual Report on Internal Control Over Financial Reporting

Company management 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, 2019. 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, 2019, 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

The Board of Directors and Stockholders of
Panhandle Oil and Gas Inc.

Opinion on Internal Control over Financial Reporting

We have audited Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2019, 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). In our opinion, Panhandle Oil and Gas Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of September 30, 2019, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the accompanying balance sheets of the Company as of September 30, 2019 and 2018, and the related statements of operations, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2019, and the related notes and our report dated December 12, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

The Company'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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control Over Financial Reporting

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.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 12, 2019

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Panhandle Oil and Gas Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2019 and 2018, the related statements of operations, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company at September 30, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2019, 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) (PCAOB), the Company's internal control over financial reporting as of September 30, 2019, 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, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1989.
Oklahoma City, Oklahoma
December 12, 2019

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2019	September 30, 2018
Assets		
Current Assets:		
Cash and cash equivalents	$ 6,160,691	$ 532,502
Oil, NGL and natural gas sales receivables (net of allowance for uncollectable accounts)	4,377,646	7,101,629
Refundable income taxes	1,505,442	33,165
Derivative contracts, net	2,256,639	-
Other	177,037	578,880
Total current assets	14,477,455	8,246,176
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	354,718,398	427,448,584
Non-producing oil and natural gas properties	14,599,023	12,563,519
Other	1,722,080	1,529,770
	371,039,501	441,541,873
Less accumulated depreciation, depletion and amortization	(259,314,590)	(243,257,472)
Net properties and equipment	111,724,911	198,284,401
Investments	205,076	219,109
Derivative contracts, net	237,505	-
Total assets	$ 126,644,947	$ 206,749,686

(Continued on next page)

See accompanying notes.

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2019	September 30, 2018
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 665,160	$ 881,130
Derivative contracts, net	-	3,064,046
Accrued liabilities and other	2,433,466	1,791,950
Total current liabilities	3,098,626	5,737,126
Long-term debt	35,425,000	51,000,000
Deferred income taxes	5,976,007	18,088,007
Asset retirement obligations	2,835,781	2,809,378
Derivative contracts, net	-	349,970
Stockholders' equity:		
Class A voting common stock, $0.01666 par value; 24,000,000 shares authorized; 16,897,306 issued at September 30, 2019; 16,896,881 issued at September 30, 2018	281,509	281,502
Capital in excess of par value	2,967,984	2,824,691
Deferred directors' compensation	2,555,781	2,950,405
Retained earnings	81,848,301	125,266,945
	87,653,575	131,323,543
Treasury stock, at cost; 558,051 shares at September 30, 2019; 145,467 shares at September 30, 2018	(8,344,042)	(2,558,338)
Total stockholders' equity	79,309,533	128,765,205
Total liabilities and stockholders' equity	$126,644,947	$206,749,686

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Operations

	Year ended September 30,		
	2019	**2018**	**2017**
Revenues:			
Oil, NGL and natural gas sales	$ 39,410,036	$ 48,385,335	$39,935,912
Lease bonuses and rentals	1,547,078	1,580,997	5,149,297
Gains (losses) on derivative contracts	6,105,145	(4,932,068)	1,249,840
Gain on asset sales	18,973,426	-	26,105
	66,035,685	45,034,264	46,361,154
Costs and expenses:			
Lease operating expenses	12,488,425	13,460,278	12,682,969
Production taxes	1,902,636	2,089,050	1,548,399
Depreciation, depletion and amortization	18,196,583	18,395,040	18,397,548
Provision for impairment	76,824,337	-	662,990
Interest expense	1,995,789	1,748,101	1,275,138
General and administrative	8,565,243	7,342,441	7,441,242
Loss on asset sales and other expense (income)	288,610	102,685	131,935
	120,261,623	43,137,595	42,140,221
Income (loss) before provision (benefit) for income taxes	(54,225,938)	1,896,669	4,220,933
Provision (benefit) for income taxes	(13,481,000)	(12,739,000)	689,000
Net income (loss)	$ (40,744,938)	$ 14,635,669	$ 3,531,933
Basic and diluted earnings (loss) per common share	$ (2.43)	$ 0.86	$ 0.21

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, 2016	16,863,004	$280,938	$ 3,191,056	$ 3,403,213	$112,482,284	(262,708)	$(4,165,672)	$115,191,819
Net income (loss)	-	-	-	-	3,531,933	-	-	3,531,933
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
Dividends declared ($0.16 per share)	-	-	-	-	(2,684,001)	-	-	(2,684,001)
Distribution of restricted stock to officers and directors	-	-	(1,010,275)	-	-	63,121	1,010,938	663
Distribution of deferred directors' compensation	-	-	(145,469)	(301,962)	-	27,216	447,431	-
Common shares to be issued to directors for services	-	-	-	358,658	-	-	-	358,658
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
Net income (loss)	-	-	-	-	14,635,669	-	-	14,635,669
Purchase of treasury stock	-	-	-	-	-	(63,404)	(1,219,228)	(1,219,228)
Issuance of treasury shares to ESOP	-	-	19,509	-	-	20,632	362,665	382,174
Restricted stock awards	-	-	655,414	-	-	-	-	655,414
Dividends declared ($0.16 per share)	-	-	-	-	(2,698,940)	-	-	(2,698,940)
Distribution of restricted stock to officers and directors	1,278	21	(845,788)	-	-	50,455	846,629	862
Distribution of deferred directors' compensation	32,599	543	269,112	(811,219)	-	31,838	541,564	-
Common shares to be issued to directors for services	-	-	-	301,715	-	-	-	301,715
Balances at September 30, 2018	16,896,881	$281,502	$ 2,824,691	$ 2,950,405	$125,266,945	(145,467)	$(2,558,338)	$128,765,205
Net income (loss)	-	-	-	-	(40,744,938)	-	-	(40,744,938)
Purchase of treasury stock	-	-	-	-	-	(515,972)	(7,454,000)	(7,454,000)
Issuance of treasury shares to ESOP	-	-	(25,830)	-	-	26,629	398,104	372,274
Restricted stock awards	-	-	771,797	-	-	-	-	771,797
Dividends declared ($0.16 per share)	-	-	-	-	(2,673,706)	-	-	(2,673,706)
Distribution of restricted stock to officers and directors	425	7	(394,824)	-	-	24,360	395,230	413
Distribution of deferred directors' compensation	-	-	(207,850)	(667,115)	-	52,399	874,962	(3)
Common shares to be issued to directors for services	-	-	-	272,491	-	-	-	272,491
Balances at September 30, 2019	16,897,306	$281,509	$ 2,967,984	$ 2,555,781	$ 81,848,301	(558,051)	$(8,344,042)	$ 79,309,533

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Cash Flows

	Year ended September 30,		
	2019	**2018**	**2017**
Operating Activities			
Net income (loss)	$(40,744,938)	$ 14,635,669	$ 3,531,933
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	18,196,583	18,395,040	18,397,548
Impairment	76,824,337	-	662,990
Provision for deferred income taxes	(12,112,000)	(12,963,000)	375,000
Gain from leasing fee mineral acreage	(1,546,298)	(1,520,262)	(5,147,957)
Proceeds from leasing fee mineral acreage	1,565,649	1,564,225	5,194,290
Net (gain) loss on sales of assets	(18,730,197)	660,597	94,889
Common stock contributed to ESOP	372,274	382,174	312,380
Common stock (unissued) to Directors' Deferred Compensation Plan	272,491	301,715	358,658
Fair value of derivative contracts	(5,908,160)	3,930,175	(944,430)
Restricted stock awards	771,797	655,414	597,940
Other	19,085	6,326	(5,783)
Cash provided (used) by changes in assets and liabilities:			
Oil, NGL and natural gas sales receivables	2,723,983	483,856	(2,298,256)
Refundable income taxes	(1,472,277)	456,780	(406,071)
Other current assets	21,116	57,752	165,557
Accounts payable	105,217	(140,600)	(103,389)
Other non-current assets	7,166	(62,295)	-
Accrued liabilities	639,856	100,328	(27,107)
Total adjustments	61,750,622	12,308,225	17,226,259
Net cash provided by operating activities	21,005,684	26,943,894	20,758,192

(Continued on next page)

Panhandle Oil and Gas Inc.
Statements of Cash Flows (continued)

	Year ended September 30,		
	2019	**2018**	**2017**
Investing Activities			
Capital expenditures	$ (3,526,007)	$(11,590,135)	$(25,807,897)
Acquisition of minerals and overrides	(5,662,869)	(11,327,371)	-
Investments in partnerships	(1,648)	3,354	(23,563)
Proceeds from sales of assets	19,515,735	1,085,137	723,700
Net cash used in investing activities	10,325,211	(21,829,015)	(25,107,760)
Financing Activities			
Borrowings under debt agreement	16,642,481	29,017,800	27,809,185
Payments of loan principal	(32,217,481)	(30,239,800)	(20,087,185)
Purchases of treasury stock	(7,454,000)	(1,219,228)	(601,853)
Payments of dividends	(2,673,706)	(2,698,940)	(2,684,001)
Net cash provided by (used in) financing activities	(25,702,706)	(5,140,168)	4,436,146
Increase (decrease) in cash and cash equivalents	5,628,189	(25,289)	86,578
Cash and cash equivalents at beginning of year	532,502	557,791	471,213
Cash and cash equivalents at end of year	$ 6,160,691	$ 532,502	$ 557,791
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ 2,031,762	$ 1,730,461	$ 1,212,878
Income taxes paid (net of refunds received)	$ 103,279	$ (232,782)	$ 720,072
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ 27,782	$ 17,216	$ 624,893
Gross additions to properties and equipment	$ 9,248,415	$ 21,711,279	$ 25,406,894
Net (increase) decrease in accounts payable for properties and equipment additions	(59,539)	1,206,227	401,003
Capital expenditures, including dry hole costs	$ 9,188,876	$ 22,917,506	$ 25,807,897

See accompanying notes.

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 Oklahoma, North Dakota, Texas, Arkansas and New Mexico, with properties located in several other states. The Company's oil, NGL and natural gas production is from interests in 6,496 wells located principally in Oklahoma, Texas, Arkansas and North Dakota. The Company does not operate any wells. Approximately 46%, 9% and 45% of oil, NGL and natural gas revenues were derived from the sale of oil, NGL and natural gas, respectively, in 2019. Approximately 19%, 13% and 68% of the Company's total sales volumes in 2019 were derived from oil, NGL and natural gas, respectively. 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.

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. The Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of crude oil, NGL and natural gas reserves on an annual basis, with a semi-annual update. These estimates are 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.

Basis of Presentation

Certain amounts (loss (gain) on asset sales and other in the Statements of Operations and presentation of deferred tax assets and liabilities in Note 4: Income Taxes) in the prior years have been reclassified to conform to the current year presentation.

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

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.

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 2019, 2018 and 2017 the Company did not have any bad debt expense. The Company's allowance for uncollectible accounts as of the Balance Sheet dates 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 reach commercial production levels. Oil and natural gas mineral and leasehold costs are capitalized when incurred.

Leasing of Mineral Rights

The Company generates lease bonuses by leasing its mineral interests to exploration and production companies. A lease agreement represents the Company's contract with a third party and generally conveys the rights to any oil, NGL or natural gas discovered, grants the Company a right to a specified royalty interest and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Company has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. The Company accounts for its lease bonuses as conveyances 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 income. 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 derivative contracts at September 30, 2019 and 2018, were with Bank of Oklahoma and Koch Supply and Trading LP. The Company’s derivative contracts with Bank of Oklahoma are secured under its credit facility with Bank of Oklahoma. The derivative contracts with Koch are unsecured. The derivative instruments have settled or will settle based on the prices below.

Derivative contracts in place as of September 30, 2019

Contract period	Production volume covered per month	Index	Contract price
Natural gas fixed price swaps			
July - December 2019	100,000 Mmbtu	NYMEX Henry Hub	$2.960
July - December 2019	100,000 Mmbtu	NYMEX Henry Hub	$2.950
July - December 2019	100,000 Mmbtu	NYMEX Henry Hub	$2.995
July 2019 - March 2020	100,000 Mmbtu	NYMEX Henry Hub	$2.982
August - December 2019	100,000 Mmbtu	NYMEX Henry Hub	$3.004
January - December 2020	80,000 Mmbtu	NYMEX Henry Hub	$2.750
Oil costless collars			
January - December 2019	1,000 Bbls	NYMEX WTI	$50.00 floor / $60.00 ceiling
January - December 2019	2,000 Bbls	NYMEX WTI	$60.00 floor / $69.25 ceiling
July - December 2019	3,000 Bbls	NYMEX WTI	$60.00 floor / $70.75 ceiling
July 2019 - June 2020	2,000 Bbls	NYMEX WTI	$65.00 floor / $76.15 ceiling
January - June 2020	2,000 Bbls	NYMEX WTI	$60.00 floor / $67.00 ceiling
January - December 2020	2,000 Bbls	NYMEX WTI	$55.00 floor / $62.00 ceiling
Oil fixed price swaps			
January - December 2019	1,000 Bbls	NYMEX WTI	$56.15
January - December 2019	2,000 Bbls	NYMEX WTI	$56.71
January - December 2019	1,000 Bbls	NYMEX WTI	$58.56
July - December 2019	2,000 Bbls	NYMEX WTI	$56.85
July - December 2019	5,000 Bbls	NYMEX WTI	$58.50
July - December 2019	1,000 Bbls	NYMEX WTI	$60.60
January - December 2020	2,000 Bbls	NYMEX WTI	$55.28
January - December 2020	2,000 Bbls	NYMEX WTI	$58.65
January - December 2020	2,000 Bbls	NYMEX WTI	$60.00

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 $2,494,144 as of September 30, 2019, and a net liability of $3,414,016 as of September 30, 2018. Realized and unrealized gains and (losses) are recorded in gains (losses) on derivative contracts on the Company's Statement of Operations. The portion of the gain (loss) on derivatives settled in cash for 2019, 2018 and 2017 was $196,985 (net received), $1,001,893 (net paid) and $305,410 (net received), respectively.

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 derivative contracts' fair values at a gross level back to net fair value presentation on the Company's Balance Sheets at September 30, 2019, and September 30, 2018. The Company has offset all amounts subject to master netting agreements in the Company's Balance Sheets at September 30, 2019, and September 30, 2018.

	9/30/2019 Fair Value Commodity Contracts		9/30/2018 Fair Value Commodity Contracts		
	Current Assets	Non-Current Assets	Current Assets	Current Liabilities	Non-Current Liabilities
Gross amounts recognized	$ 2,256,639	$ 237,505	$ 42,150	$3,106,196	$ 349,970
Offsetting adjustments	-	-	(42,150)	(42,150)	-
Net presentation on Balance Sheets	$ 2,256,639	$ 237,505	$ -	$3,064,046	$ 349,970

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

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: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity fixed-price swaps and commodity options (i.e. price collars).

The Company uses an option pricing valuation model for option derivative contracts that considers various inputs including: future prices, time value, volatility factors, counterparty credit risk and current market and contractual prices for the underlying instruments. The values calculated are then compared to the values given by counterparties for reasonableness.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and unobservable (or less observable) from objective sources (supported by little or no market activity).

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, 2019			
	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	$ -	$1,892,954	$ -	$1,892,954
Derivative Contracts - Collars	$ -	$ 601,190	$ -	$ 601,190

	Fair Value Measurement at September 30, 2018			
	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	$ -	$(2,317,069)	$ -	$(2,317,069)
Derivative Contracts - Collars	$ -	$(1,096,947)	$ -	$(1,096,947)

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,					
	2019		2018		2017	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Producing Properties [a]	$9,101,032	$76,824,337	$ -	$ -	$567,077	$ 662,990

[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, 2019, and September 30, 2018, the carrying values of cash and cash equivalents, receivables, and payables are considered to be representative of their respective fair values due to the short-term maturities of those instruments. Financial instruments include long-term debt, which the valuation is classified as Level 2 as the carrying amount of the Company's revolving credit facility approximates fair value because the interest rates are reflective of market rates. The estimated current market interest rates are based primarily on interest rates currently being offered on borrowings of similar amounts and terms. In addition, no valuation input adjustments were considered necessary relating to nonperformance risk for the debt agreements.

Properties and Equipment

Depreciation, Depletion and Amortization

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 $9,673,787 and $8,025,015 at September 30, 2019 and 2018, respectively, consisting of perpetual ownership of mineral interests in several states, with 91% of the acreage in Oklahoma, North Dakota, Texas, Arkansas and New Mexico. As mentioned, these mineral rights are perpetual and have been accumulated over the 93-year life of the Company. There are approximately 197,468 net acres of non-producing minerals in more than 6,688 tracts owned by the Company. An average tract contains approximately 30 acres, and the average cost per acre is $73. 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 on these mineral interests each year. 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 Company's mineral ownership consists 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 (by mineral deed).

When a new well is drilled on our mineral acreage, all of the non-producing mineral costs for the associated mineral deed are transferred to producing minerals and are amortized straight-line over a 20-year period (insignificant fields are amortized over 10-year period). Management has historically chosen to move non-producing mineral costs in this manner, as it is very difficult for the Company, as a non-operator, to predict well spacing and timing of drilling on all of the minerals that we have purchased over the long life of the Company. Given that we are moving all of the costs to the first new well drilled on each mineral deed, we believe that a straight-line amortization over a 20-year period is appropriate as these wells and future development will deplete these assets over a fairly long period.

Impairment

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, market quotes where available 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, 2019, is based on the best information available as of that date, including estimates of forward oil, NGL and natural gas prices and costs along with market quotes for specific assets. 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 $76,824,337, $0 and $662,990 for 2019, 2018 and 2017, respectively.

At the end of 2019, impairment of $76,560,376 was recorded on our Eagle Ford assets. The remaining $263,961 of impairment was taken on other assets. The impairment on the Eagle Ford assets was caused by the Company making the strategic decision to cease participating with a working interest on its mineral and leasehold acreage going forward and therefore removing all working interest PUDs from the Company's reserve reports. The removal of the PUDs caused the Eagle Ford assets to fail the step one test for impairment, as its undiscounted cash flows were not high enough to cover the book basis of the assets. These assets were written down to their fair market value as required by GAAP. The Company determined the fair value based on discounted cash flows of the properties as well as active market bids received from interested potential buyers. The discounted cash flows of the properties were prepared using NYMEX strip pricing as of year-end, using a discount rate of 10% for proved developed and assigning no value to undeveloped locations. Market bids received from interested potential buyers corroborated the fair value of the discounted cash flows as of year-end. The fair value was determined to be $9.1 million based on the discounted cash flows and market quotes. The Company decided not to sell the assets after the marketing process was complete, as we believed that the market conditions were not ideal for selling at that time and that the highest and best use of the assets was to continue to own and produce out the Eagle Ford properties.

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.

Divestitures

During the 2019 fiscal year, the Company sold 112 non-core wells and 890 net mineral and non-participating royalty interest acres for $19,515,735 and recorded a net gain on sales of $18,730,197. The total net book value that was removed from the Balance Sheets due to these sales was approximately $786,000. On the Statements of Operations, the net gain is reflected in the Gain on asset sales line item with a balance of $18,973,426 with an offset to the Loss on asset sales line item in the amount of $243,228.

During the 2018 fiscal year, the Company sold 324 non-core marginal wells for $1,085,137 and recorded a net loss on the sales of $660,597. The total net book value that was removed from the Balance Sheets due to these sales was approximately $1.7 million. The loss on sales was included in the Loss on asset sales and other line of the Statements of Operations.

Acquisitions

During the 2019 fiscal year, the Company acquired mineral acreage in the cores of the Bakken in North Dakota and the STACK and SCOOP plays in Oklahoma. The Company acquired a total of 790 net mineral acres for $5.7 million or an average of approximately $7,200 per net mineral acre. These mineral purchases were accounted for as asset acquisitions.

During the 2018 fiscal year, the Company acquired mineral acreage in the cores of the Bakken in North Dakota and the STACK and SCOOP plays in Oklahoma. The Company acquired a total of 4,306 net mineral acres for $11.3 million or an average of approximately $2,600 per net mineral acre. These mineral purchases were accounted for as asset acquisitions.

Capitalized Interest

During 2019, 2018 and 2017, interest of $38,606, $89,023 and $168,351, respectively, was included in the Company's capital expenditures. Interest of $1,995,789, $1,748,101 and $1,275,138, 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.

Accrued Liabilities

The following table shows the balances for the years ended September 30, 2019 and 2018, relating to the Company's accrued liabilities:

	Year Ended September 30,	
	2019	2018
Accrued compensation	$ 1,446,710	$ 905,445
Revenues payable	396,954	253,850
Accrued ad valorem	260,550	317,105
Other	329,252	315,550
Total accrued liabilities	$ 2,433,466	$ 1,791,950

The increase in accrued compensation is primarily due to the one-time severance with the Company's former CEO of approximately $670,000 upon his resignation towards the end of fiscal 2019. This increase was somewhat offset by a decrease in the overall bonus accrual for 2019 as compared to 2018.

The increase in revenues payable was primarily due to oil, NGL and natural gas revenues received on properties sold during 2019 that related to production after the effective date of the sale.

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, 2019 and 2018, relating to the Company's asset retirement obligations:

	2019	2018
Asset retirement obligations as of beginning of the year	$ 2,809,378	$ 3,196,889
Wells acquired or drilled	27,783	17,215
Wells sold or plugged	(134,090)	(542,892)
Accretion of discount	132,710	138,166
Asset retirement obligations as of end of the year	$ 2,835,781	$ 2,809,378

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 can gather from outside sources as well as relevant information that we receive directly from operators.

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 (on working interest wells only). 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, 2019 and 2018, 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 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 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 Tax Cuts and Jobs Act was enacted on December 22, 2017. The Act reduced the U.S. federal corporate tax rate from 35% to 21%. As of September 30, 2018, we completed our estimates accounting for the tax effects of the Act. Based on these estimates, we recognized an

amount which was included as a component of income tax expense (benefit) from continuing operations in 2018.

We remeasured certain deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21%. The amount recorded related to the remeasurement of our deferred tax balance was $12,464,000 income tax benefit.

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

Both excess federal percentage depletion, which is limited to certain production volumes and by certain income levels, and excess Oklahoma percentage depletion, which has no limitation on production volume, reduce estimated taxable income or add to estimated taxable loss projected for any year. Federal and Oklahoma excess percentage depletion, when a provision for income taxes is expected for the year, decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is expected for the year. The benefits of federal and Oklahoma excess percentage depletion and excess tax benefits and deficiencies of stock-based compensation are not directly related to the amount of pre-tax income (loss) recorded in a period. Accordingly, in periods where a recorded pre-tax income or loss is relatively small, the proportional effect of these items on the effective tax rate may be significant. The effective tax rate for the year ended September 30, 2018, was a 672% benefit, as compared to a 25% benefit for the year ended September 30, 2019.

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 2016.

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, 2019, 2018 and 2017, the Company's interest and penalties were not material. The Company does not believe it has any significant uncertain tax positions.

Adoption of New Accounting Pronouncements

Revenue recognition and presentation – In May 2014, the FASB issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which supersedes nearly all previously existing revenue recognition guidance under U.S. GAAP. Subsequently, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, *Revenue from Contracts with Customers (Topic 606):*

Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This new guidance became effective for reporting periods beginning after December 15, 2017. The Company adopted the new revenue recognition and presentation guidance on October 1, 2018, as required. See Note 3: Revenues for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New Accounting Pronouncements yet to be Adopted

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires lessees to recognize a lease liability and a right-of-use (ROU) asset on the balance sheet for all leases, including operating leases, with terms in excess of 12 months. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The standard will not apply to our leases of mineral rights to explore for or use oil and natural gas resources, including the intangible rights to explore for those natural resources and rights to use the land in which those natural resources are contained, as these are accounted for under ASC 932. The Company plans to make certain elections permitting us to not reassess whether any expired or existing contracts contained leases, permitting us to not reassess the lease classification for any expired or existing leases (all existing leases that were classified as operating leases in accordance with Topic 840 will be classified as operating leases) and permitting us to not reassess initial direct costs for any existing leases.

The Company has completed the assessment of contracts potentially affected by the new standard and has completed the assessment of the accounting treatment for these leases. The adoption will primarily impact other assets and other liabilities and will also impact ongoing disclosures but will not have a material impact on our balance sheet, results of operations or cash flows. We plan to adopt the new standard on October 1, 2019, the effective date, and as permitted by ASU 2018-11 we will not adjust comparative-period financial statements and will continue to apply the guidance in ASC 840, including its disclosure requirements, in the comparative periods presented prior to adoption.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. This standard changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost. The standard is effective for interim and annual periods beginning after December 15, 2019, and shall be applied using a modified retrospective approach resulting in a cumulative effect adjustment to retained earnings upon adoption. This standard will be effective for Panhandle starting October 1, 2020. The Company is evaluating the new standard and is unable to estimate its financial statement impact at this time; however, the impact is not expected to be material. Historically, the Company's credit losses on oil, NGL and natural gas sales receivables have been immaterial.

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 $122,659, $0 and $0 in 2020, 2021 and 2022, respectively. Total rent expense incurred by the Company was $218,899 in 2019, $215,803 in 2018 and $206,366 in 2017.

3. REVENUES

Lease bonus income

The Company also earns income from lease bonuses. The Company generates lease bonus income by leasing its mineral interests to exploration and production companies. A lease agreement represents the Company's contract with a third party and generally conveys the rights to any oil, NGL or natural gas discovered, grants the Company a right to a specified royalty interest and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Company has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. The Company accounts for its lease bonuses as conveyances 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 rental income line item on the Company’s Statements of Operations.

Oil and natural gas derivative contracts

See Note 1 for discussion of the Company’s accounting for derivative contracts.

Adoption of new revenue recognition and disclosure guidance

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation and recognize revenue as obligations are satisfied. Additionally, the standard requires expanded disclosures related to revenue recognition.

Subsequent to the issuance of ASU 2014-09, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)*, pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. This guidance requires an entity to record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity shall record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer.

The Company adopted the new revenue recognition and presentation guidance 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 and utilizes a cumulative effect adjustment to retained earnings in the period of adoption to account for prior period effects rather than restating previously reported results. The Company chose to use the modified retrospective method upon adoption and has applied the guidance only to contracts that are not complete at the date of initial application. Adoption of the new guidance had no cumulative effect impact on the Company's retained earnings at October 1, 2018.

The standard did not have a material effect on the timing or measurement of the Company's revenue recognition or its financial position, results of operations, net income and cash flows. Additionally, the application of ASU 2016-08’s gross versus net presentation guidance did not impact the Company’s presentation of revenues and expenses. As the Company’s interests in oil and natural gas properties are non-operated interests or royalty interests, the Company evaluated its agreements with operators in connection with the ASC 606 principal versus agent indicators. Consistent with previous conclusions under ASC 605, the Company concluded that the operators act as an agent in the transfer of commodities to third-party customers. This determination required judgment in the application of the guidance for principal versus agent under ASC 606.

Revenues from Contracts with Customers

Oil, NGL and natural gas sales

Sales of oil, NGL and natural gas are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. Oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. The price the Company receives for natural gas and NGL is tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality and heat content of natural gas, and prevailing supply and demand conditions, so that the price of natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. Each unit of commodity is considered a separate performance obligation; however, as consideration is variable, the Company utilizes the variable consideration allocation exception permitted under the standard to allocate the variable consideration to the specific units of commodity to which they relate.

Disaggregation of oil, NGL and natural gas revenues

The following table presents the disaggregation of the Company's oil, NGL and natural gas revenues for the year ended September 30, 2019.

	Year Ended September 30, 2019		
	Royalty Interest	Working Interest	Total
Oil revenue	$ 7,057,906	$ 11,072,081	$ 18,129,987
NGL revenue	1,148,033	2,549,920	3,697,953
Natural gas revenue	5,785,686	11,796,410	17,582,096
Oil, NGL and natural gas sales	$ 13,991,625	$ 25,418,411	$ 39,410,036

Performance obligations

The Company satisfies the performance obligations under its oil and natural gas sales contracts upon delivery of its production and related transfer of title to purchasers. Upon delivery of production, the Company has a right to receive consideration from its purchasers in amounts that correspond with the value of the production transferred.

Allocation of transaction price to remaining performance obligations

Oil, NGL and natural gas sales

As the Company has determined that each unit of product generally represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. The Company has utilized the practical expedient in ASC 606, which permits the Company to allocate variable consideration to one or more but not all performance obligations in the contract if the terms of the variable payment relate specifically to the Company’s efforts to satisfy that performance obligation and allocating the variable amount to the performance obligation is consistent with the allocation objective under ASC 606. Additionally, the Company will not disclose variable consideration subject to this practical expedient.

Prior-period performance obligations and contract balances

The Company records revenue in the month production is delivered to the purchaser. As a non-operator, the Company has limited control and visibility into the timing of when new wells start producing and production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices for these properties are estimated and recorded within the Oil, NGL and natural gas sales receivables line item in the accompanying Balance Sheets. The difference between the Company's estimates and the actual amounts received for oil, NGL and natural gas sales is recorded in the quarter that payment is received from the third party. For the years ended September 30, 2019, 2018 and 2017, revenue recognized in these reporting periods related to performance obligations satisfied in prior reporting periods was immaterial and considered a change in estimate.

4. INCOME TAXES

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

	2019	2018	2017
Current:			
Federal	$ (1,388,000)	$ 204,000	$ 314,000
State	19,000	20,000	-
	(1,369,000)	224,000	314,000
Deferred:			
Federal	(9,763,000)	(13,240,000)	390,000
State	(2,349,000)	277,000	(15,000)
	(12,112,000)	(12,963,000)	375,000
	$(13,481,000)	$(12,739,000)	$ 689,000

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:

	2019	2018	2017
Provision (benefit) for income taxes at statutory rate	$(11,387,447)	$ 465,253	$1,477,327
Percentage depletion	(431,340)	(577,780)	(570,801)
State income taxes, net of federal provision (benefit)	(1,986,850)	36,980	3,900
Effect of graduated rates	-	-	85,644
Restricted stock tax benefit	185,000	(69,000)	(238,000)
Deferred directors compensation benefit	(38,000)	(134,000)	(79,000)
Law change (a)	-	(12,464,000)	-
Other	177,637	3,547	9,930
	$(13,481,000)	$(12,739,000)	$ 689,000

(a) This is the tax effect of the Tax Cuts and Jobs Act (enacted in December 2017) on our deferred tax liabilities. This Act reduced the U.S. federal corporate tax rate from 35% to 21%.

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:

	2019	2018
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 8,885,776	$ 23,885,522
Derivative contracts	619,392	-
	9,505,168	23,885,522
Deferred tax assets:		
State net operating loss carry forwards	431,977	551,435
AMT credit carry forwards	1,387,042	2,936,457
Asset retirement obligations	459,810	420,761
Deferred directors' compensation	602,394	693,592
Restricted stock expense	119,697	238,477
Derivative contracts	-	839,573
Business interest limitation	358,110	-
Other	170,131	117,220
	3,529,161	5,797,515
Net deferred tax liabilities	$ 5,976,007	$ 18,088,007

Included in state net operating loss carry forwards at September 30, 2019, the Company had a deferred tax asset of $381,906 related to Oklahoma state income tax net operating loss (OK NOL) carry forwards expiring in 2037. There is no valuation allowance for the OK NOLs, as management believes they will be utilized before they expire.

The AMT carry forwards do not have an expiration date. The corporate alternative minimum tax was repealed by The Tax Cuts and Jobs Act (enacted on December 22, 2017). Taxpayers with AMT credit carryovers can use the credits to offset regular tax liability for any taxable year. In addition, the AMT credit is refundable in any taxable year beginning after 2017 and before 2022 in an amount equal to 50% (100% in the case of taxable years beginning in 2021) of the excess of the minimum tax credit for the taxable year over the amount of the credit allowable for the year against regular tax liability. Thus, the Company’s entire AMT credit carryforward amounts are fully refundable by 2023.

The Company also had a deferred asset of $358,110 related to business interest limitations. This deferred asset does not expire and the Company does not have a valuation allowance for this asset, as we believe that it will be utilized in the future.

5. 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 $70,000,000 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 $74,435,747 at September 30, 2019. The interest rate is based on BOK prime plus from 0.50% to 1.25%, or 30-day LIBOR plus from 2.00% to 2.75%. 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, 2019, the effective interest rate was 4.34%.

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.

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. The borrowing base for the credit facility was redetermined in August 2019 by the banks and reduced to $70,000,000. 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. The loan agreement sets limits on dividend payments and stock repurchases if those payments would cause the leverage ratio to go above 2.75 to 1.0. 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 the 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, 2019, the Company was in compliance with the covenants of the loan agreement and had $34,575,000 of availability under its outstanding credit facility.

6. STOCKHOLDERS' EQUITY

Upon approval by the stockholders of the Company's 2010 Restricted Stock Plan in March 2010, as amended in May 2018, the board of directors approved to continue to allow management to repurchase up to $1.5 million of the Company's common stock at their discretion. The repurchase of an additional $1.5 million of the Company's common stock continues to be authorized and approved effective when the previous amount is utilized. The Board added language to clarify that this is intended to be an evergreen provision. The number of shares allowed to be purchased by the Company under the repurchase program is no longer capped at an amount equal to the aggregate number of shares of common stock (i) awarded pursuant to the Company's Amended 2010 Restricted Stock Plan, (ii) contributed by the Company to its ESOP, and (iii) credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors. For the year ended September 30, 2019, $7,454,000 had been spent to purchase 515,972 shares. The shares are held in treasury and are accounted for using the cost method.

7. EARNINGS (LOSS) PER SHARE

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

	Year Ended September 30,		
	2019	2018	2017
Numerator for basic and diluted earnings (loss) per share:			
Net income (loss)	$(40,744,938)	$14,635,669	$ 3,531,933
Denominator for basic and diluted earnings per share:			
Weighted average shares (including for 2019, 2018 and 2017, unissued, vested directors' shares of 168,586, 205,736 and 253,603, respectively)	16,743,746	16,952,664	16,900,185

8. 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. Compensation expense is equal to the contributions for each year. The 182,337 shares of the Company's Common Stock held by the plan as of September 30, 2019, 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
2019	26,629	$ 372,274
2018	20,632	$ 382,174
2017	13,125	$ 312,380

9. 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, when issued, over annual time periods up to ten years. These unissued shares are recorded to each director's deferred compensation account at the closing market price of the shares (i) on the dates of the Board and committee meetings, and (ii) on the payment dates of the annual retainers. Only

upon a director's retirement, termination, death or a change-in-control of the Company will the shares recorded for such director under the 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, 2019, there were 179,226 shares (212,574 shares at September 30, 2018) recorded under the Plan. The deferred balance outstanding at September 30, 2019, under the Plan was $2,555,781 ($2,950,405 at September 30, 2018). Expenses totaling $272,491, $301,715 and $358,658 were charged to the Company's results of operations for the years ended September 30, 2019, 2018 and 2017, respectively, and are included in general and administrative expense in the accompanying Statements of Operations.

10. RESTRICTED STOCK PLAN

In March 2010, stockholders 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 stockholders. In March 2014, stockholders 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 stockholders.

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 awards 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

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. Forfeitures of awards are recognized when they occur. The dilutive impact of all restricted stock plans is immaterial for all periods presented.

The following table summarizes the Company's pre-tax compensation expense for the years ended September 30, 2019, 2018 and 2017, related to the Company's performance based and non-performance based restricted stock.

	Year Ended September 30,		
	2019	2018	2017
Performance based, restricted stock	$ 367,091	$ 276,272	$ 233,122
Non-performance based, restricted stock	404,706	379,142	364,818
Total compensation expense	$ 771,797	$ 655,414	$ 597,940

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	$ 105,592	1.95
Non-performance based, restricted stock	166,100	1.36
Total	$ 271,692	

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

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

	Performance Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value	Non-Performance Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value
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
Granted	29,099	11.34	19,918	20.77
Vested	(35,485)	12.18	(16,248)	19.34
Forfeited	-	-	-	-
Unvested shares as of September 30, 2018	92,704	$ 11.00	28,667	$ 20.40
Granted	43,287	8.24	27,978	15.61
Vested	-	-	(24,785)	18.30
Forfeited	(89,321)	10.08	(13,153)	18.23
Unvested shares as of September 30, 2019	46,670	$ 10.21	18,707	$ 17.54

The intrinsic value of the vested shares in 2019 was $368,259.

11. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

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

The following table shows sales, by percentage, through various operators/purchasers during 2019, 2018 and 2017.

	2019	2018	2017
Company A	23%	24%	18%
Company B	8%	16%	3%
Company C	8%	11%	8%
Company D	5%	7%	13%

The loss of any of these major purchasers of oil, NGL and natural gas production could have a material adverse effect on the ability of the Company to produce and sell its oil, NGL and natural gas production.

12. SUBSEQUENT EVENTS

On November 14, 2019, Panhandle closed on the sale of 530 net mineral acres in Eddy County, New Mexico, for $3.4 million.

On November 22, 2019, Panhandle signed a PSA to acquire 704 net mineral acres in Kingfisher, Canadian and Garvin Counties, Oklahoma, for a purchase price of $9.65 million (subject to normal closing adjustments). We expect to close on this purchase by the end of the calendar year and it will be mostly funded with cash from our like-kind exchange sales.

13. 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:

	2019	2018
Producing properties	$ 354,718,398	$ 427,448,584
Non-producing minerals	14,413,899	12,378,395
Non-producing leasehold	185,124	185,124
Exploratory wells in progress	-	-
	369,317,421	440,012,103
Accumulated depreciation, depletion and amortization	(258,063,849)	(242,169,604)
Net capitalized costs	$ 111,253,572	$ 197,842,499

Costs Incurred

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

	2019	2018	2017
Property acquisition costs	$6,235,905	$11,409,673	$ 20,190
Exploration costs	-	-	-
Development costs	3,012,095	10,291,476	25,382,377
	$9,248,000	$21,701,149	$25,402,567

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 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, prepared the Company's oil, NGL and natural gas reserves estimates as of September 30, 2019, 2018 and 2017.

The Company's net proved oil, NGL and natural gas reserves, which are located in the contiguous United States, as of September 30, 2019, 2018 and 2017, 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. 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 36 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 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, 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.

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, 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
Revisions of previous estimates	(1,407,995)	303,728	(29,247)	(6.7)
Acquisitions (divestitures)	236,690	24,765	(1,782,949)	(0.2)
Extensions, discoveries and other additions	1,982,624	476,174	9,400,374	24.2
Production	(336,564)	(255,176)	(8,721,262)	(12.3)
September 30, 2018	5,984,422	2,934,190	120,062,036	173.6
Revisions of previous estimates	(3,266,351)	(890,046)	(35,644,135)	(60.6)
Acquisitions (divestitures)	(322,023)	(18,881)	(948,496)	(3.0)
Extensions, discoveries and other additions	313,241	164,276	3,891,262	6.8
Production	(329,199)	(216,259)	(7,086,761)	(10.4)
September 30, 2019	2,380,090	1,973,280	80,273,906	106.4

The prices used to calculate reserves and future cash flows from reserves for oil, NGL and natural gas, respectively, were as follows: September 30, 2019 - $54.40/Bbl, $19.30/Bbl, $2.48/Mcf; September 30, 2018 - $62.86/Bbl, $26.13/Bbl, $2.56/Mcf; September 30, 2017 - $46.31/Bbl, $17.55/Bbl, $2.81/Mcf.

The revisions of previous estimates from 2018 to 2019 were primarily the result of:

- Negative pricing revisions of 4.4 Bcfe, primarily resulting from oil and natural gas wells currently projected to reach their economic limits earlier than was projected in 2018 due to lower oil prices and higher natural gas price deducts in 2019 relative to 2018; proved developed revisions of 4.3 Bcfe and PUD revisions of 0.1 Bcfe.

- Negative revisions of 56.2 Bcfe. Proved undeveloped negative revisions of 48.2 Bcfe were the result of the Company implementing the new strategy of not participating with a working interest in future drilling programs, which resulted in removal of undeveloped leasehold wells, including the Eagle Ford Shale, and lowering the net revenue interest on previously planned working interest wells on our mineral acreage to a royalty revenue interest only. These proved undeveloped locations remaining are in active areas of our core mineral acreage. Proved developed revisions were negative 8.0 Bcfe, principally due to lower performance of our high-interest Woodford gas wells drilled in 2017 in the Arkoma Stack and, to a lesser extent, lower performance of the Fayetteville Shale gas properties in Arkansas.

Acquisitions and divestitures were the result of:

- The acquisition of 0.8 Bcfe, predominately in the active drilling program of the Bakken in North Dakota; 0.5 Bcfe were proved developed and 0.3 Bcfe were proved undeveloped.

- The sale of 3.8 Bcfe, predominately in the Permian Basin in Texas and New Mexico; 2.2 Bcfe were proved developed and 1.6 Bcfe were proved undeveloped.

Extensions, discoveries and other additions from 2018 to 2019 are principally attributable to:

- Proved developed reserve extensions, discoveries and other additions of 2.1 Bcfe resulting from:

  a) The Company's royalty interest ownership in the ongoing development of unconventional oil, NGL and natural gas utilizing extended horizontal drilling in the Woodford Shale in the STACK, SCOOP and Arkoma Stack in Oklahoma.

  b) The Company's royalty interest ownership in ongoing development of unconventional oil, NGL and natural gas utilizing horizontal drilling in the STACK Meramec play in the Anadarko Basin in western Oklahoma.

  c) The Company's royalty interest ownership in ongoing development of conventional and unconventional oil, NGL and natural gas utilizing horizontal drilling in the Permian Basin.

- The addition of 4.7 Bcfe of PUD reserves within the Company's active drilling program areas of 1) the STACK Meramec in western Oklahoma 2) the SCOOP Woodford Shale in western Oklahoma, 3) the Woodford Shale in the Arkoma Stack, 4) the Marmaton in Ellis County, Oklahoma, and 5) the Yeso in Eddy County, New Mexico.

- Production of 10.4 Bcfe from the Company's oil and natural gas properties.

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)
September 30, 2017	2,201,528	1,768,425	87,861,043	3,308,139	616,274	33,334,077
September 30, 2018	2,334,587	2,085,706	83,151,954	3,649,835	848,484	36,910,082
September 30, 2019	1,863,096	1,747,242	67,713,193	516,994	226,038	12,560,713

The following details the changes in proved undeveloped reserves for 2019 (Mcfe):

Beginning proved undeveloped reserves	63,899,996
Proved undeveloped reserves transferred to proved developed	(1,763,402)
Revisions	(48,404,716)
Extensions and discoveries	4,679,986
Sales	(1,648,780)
Purchases	255,821
Ending proved undeveloped reserves	17,018,905

For the fiscal year ending September 30, 2019, our beginning PUD reserves were 63.9 Bcfe. In 2019, a total of 1.8 Bcfe (3% of the beginning balance) was transferred to proved developed. The 48.4 Bcfe (76% of the beginning balance) of negative revisions to PUD reserves were pricing revisions of 0.2 Bcfe and a revision of 48.2 Bcfe, predominately resulting from the removal of oil, NGL and natural gas reserves associated with working interest in Eagle Ford wells and working interests in wells in STACK, SCOOP and Arkoma Stack plays consistent with the Company implementing the strategy to no longer participate with working interests moving forward. The proved undeveloped locations remaining are royalty interest only and are in active areas of our core mineral acreage. We anticipate that all the Company's current 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 4.7 Bcfe of royalty interest PUD reserves in 2019 within the active drilling program areas of 1) the SCOOP Woodford Shale in western Oklahoma, 2) the Anadarko Basin STACK Meramec in western Oklahoma, 3) the Marmaton in Ellis County, Oklahoma, 4) the Arkoma Stack in eastern Oklahoma and 5) the Yeso in Eddy County, New Mexico. These additions result from continuing development and additional well performance data in each of the referenced plays. Additionally, the Company purchased 0.3 Bcfe in the Bakken in North Dakota and sold 1.6 Bcfe, predominately in the Permian Basin in Texas and New Mexico.

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.

	2019	2018	2017
Future cash inflows	$ 366,697,321	$ 759,899,074	$ 637,509,599
Future production costs	(153,935,373)	(259,413,766)	(256,193,675)
Future development and asset retirement costs	(1,917,937)	(89,518,449)	(93,133,683)
Future income tax expense	(47,788,416)	(95,872,182)	(102,193,819)
Future net cash flows	163,055,595	315,094,677	185,988,422
10% annual discount	(77,494,066)	(158,768,823)	(105,155,847)
Standardized measure of discounted future net cash flows	$ 85,561,529	$ 156,325,854	$ 80,832,575

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

	2019	2018	2017
Beginning of year	$156,325,854	$ 80,832,575	$ 29,770,119
Changes resulting from:			
Sales of oil, NGL and natural gas, net of production costs	(25,072,122)	(32,836,007)	(25,783,055)
Net change in sales prices and production costs	(76,588,460)	47,533,281	37,186,619
Net change in future development and asset retirement costs	43,607,535	1,580,942	(7,939,156)
Extensions and discoveries	7,074,245	34,667,557	38,582,908
Revisions of quantity estimates	(60,308,497)	(8,391,223)	15,282,587
Acquisitions (divestitures) of reserves-in-place	(3,134,783)	(307,472)	(962,667)
Accretion of discount	20,457,930	12,602,209	4,789,294
Net change in income taxes	23,413,194	(3,057,128)	(27,070,430)
Change in timing and other, net	(213,367)	23,701,120	16,976,356
Net change	(70,764,325)	75,493,279	51,062,456
End of year	$ 85,561,529	$156,325,854	$ 80,832,575

14. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

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

	Fiscal 2019 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 26,328,994	$ 7,636,213	$16,342,394	$ 15,728,084
Income (loss) before provision for income taxes	$ 16,306,940	$ (2,061,334)	$ 5,919,236	$ (74,390,780)
Net income (loss)	$ 12,735,940	$ (1,931,334)	$ 4,604,236	$ (56,153,780)
Earnings (loss) per share	$ 0.75	$ (0.11)	$ 0.28	$ (3.35)

	Fiscal 2018 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 12,490,526	$11,421,258	$ 9,557,937	$ 11,564,543
Income (loss) before provision for income taxes	$ 1,074,939	$ 1,046,176	$ (984,093)	$ 759,647
Net income (loss)	$ 13,784,939	$ 1,070,176	$ (775,093)	$ 555,647
Earnings (loss) per share	$ 0.81	$ 0.06	$ (0.05)	$ 0.04

ITEM 9 CHANGES 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 Interim 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 Interim 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). Our internal control structure is designed to provide reasonable assurance to our management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of our financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles. The Company's management, including the Interim 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, 2019.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent registered public accounting firm, Ernst & Young LLP, has issued an attestation report regarding its assessment of the Company's internal control over

financial reporting as of September 30, 2019, presented preceding the Company's financial statements included in this Form 10-K. Additionally, the financial statements for the years ended September 30, 2018 and 2017, covered in this 2019 Annual Report on Form 10-K, have also been audited by the Company's independent registered public accounting firm, whose report is presented preceding the their report on the Company's internal control over financial reporting.

(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, 2019, 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 and Corporate Governance, 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 Accounting 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

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, January 19, 2017, and April 3, 2018)
(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 (incorporated by reference to Form 10-K dated December 12, 2017)
(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)
(10.7)	Fifth Amendment to Amended and Restated Credit Agreement and Joinder dated July 2, 2018 (incorporated by reference to Form 8-K dated July 2, 2018)
(10.8)	Sixth Amendment to Amended and Restated Credit Agreement and Joinder dated August 6, 2019 (Incorporated by reference to Form 10-Q dated August 8, 2019)
(10.9)	Transition Agreement between Panhandle Oil and Gas Inc. and Paul F. Blanchard, former CEO effective August 26, 2019
(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
(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

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/ Chad L. Stephens III
Chad L. Stephens III
Interim Chief Executive Officer

Date: December 12, 2019

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

Signature	Title	Date
/s/ Chad L. Stephens III Chad L. Stephens III	Interim Chief Executive Officer, Director	December 12, 2019
/s/Robb P. Winfield Robb P. Winfield	Vice President, Chief Financial Officer and Controller	December 12, 2019
/s/ Mark T. Behrman Mark T. Behrman	Lead Independent Director	December 12, 2019
/s/ Lee M. Canaan Lee M. Canaan	Director	December 12, 2019
/s/ Peter B. Delaney Peter B. Delaney	Director	December 12, 2019
/s/ Christopher T. Fraser Christopher T. Fraser	Director	December 12, 2019
/s/ Robert E. Robotti Robert E. Robotti	Director	December 12, 2019

EXHIBIT 10.9

TRANSITION AGREEMENT

This Transition Agreement (the "***Agreement***"), between Panhandle Oil and Gas, Inc. ("***Panhandle***") and Paul F. Blanchard ("***Blanchard***") (collectively, the "***Parties***") is effective as of the 26th day of August 2019 (the "***Effective Date***").

WHEREAS, Panhandle has decided to end the employer/employee relationship with Blanchard on the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the mutual promises set forth herein, the sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. Termination of Employment Relationship. Blanchard's employment with Panhandle will cease on September 30, 2019 (the "***Termination Date***"). On the Effective Date, Blanchard hereby resigns as a Director of the Panhandle Board of Directors and as an Officer of Panhandle. Blanchard shall remain an active employee of Panhandle with pay and benefits until the Termination Date. During the period between the Effective Date and the Termination Date, (the "***Transition Period***") Blanchard will work as an advisor at the direction of the Interim CEO to cooperate and assist in the transition of job duties and responsibilities. The Parties have agreed to certain conditions as set forth in this Agreement as consideration for Blanchard signing the General Release attached as Exhibit A on or before September 20, 2019 and, the General Release attached as Exhibit B within 21 days of the Termination Date.

2. Transition/Severance Payments. Panhandle shall make certain payments outlined below (the "***Transition Payment***" or "***Severance Payment***") as consideration for Blanchard signing each General Release and complying with the terms of this Agreement. If Blanchard signs this Agreement, Panhandle will continue payment of Blanchard's current Base Salary from the Effective Date through the Termination Date. Blanchard states that as of the Effective Date, he has been paid all wages due and owing to him.

The Severance Payment shall be: A lump sum payment equal to (i) one year of Employee's annualized salary in the amount of Three Hundred Twenty-Six Thousand Five Hundred Dollars ($326,500); and, (ii) an annual bonus payment in the amount of Three Hundred Twenty-Six Thousand Five Hundred Dollars ($326,500); and, (iii) an amount equal to the cost of extending medical coverage for Blanchard and his spouse and/or eligible dependents, (as applicable and to the extent such participation is allowed by the terms of the medical plan maintained by Panhandle) under the Panhandle medical plan as available under the Consolidated Omnibus Reconciliation Act of 1986 ("***COBRA***") for a period of 12 months following the Termination Date. Additionally, as part of the Severance Payment, Panhandle will accelerate vesting on 100% of the 3950 shares purchased pursuant to the Stock Purchase and Restriction Agreement, 2016 Non-Performance share grant. Blanchard will also be eligible for the 2019 bonus (including discretionary component) to the extent the relevant metrics are met as determined by the Board of Directors.

The Severance Payment will be paid in one lump sum in accordance with Panhandle normal payroll practices in effect on the Termination Date, provided the payment shall not occur until Blanchard signs and does not revoke the General Release attached as Exhibit B within 21 days after the Termination Date. The Severance Payment will be subject to standard withholding for taxes and other deductions in accordance with usual payroll policy.

Except as otherwise provided in the Agreement, Blanchard acknowledges he is not vested in any shares purchased under any Stock Purchase and Restriction Agreement: Performance Shares; and, Panhandle will exercise its repurchase option as to those shares. Blanchard further acknowledges that he is not vested in any Stock Purchase and Restriction Agreement: Non Performance Shares purchased under the 2017 and 2018 grants and Panhandle will exercise the option to repurchase all shares. If Blanchard does not sign or if he revokes his signature on the General Release attached as Exhibit B, Panhandle will also repurchase all shares purchased under the 2016 grant.

3. Outplacement Assistance. If Blanchard signs and does not revoke his signature on the General Release attached as Exhibit A, as a Transition Payment, Panhandle will pay an additional sum for Blanchard to receive outplacement services from a provider selected by Panhandle. Panhandle will pay the outplacement services company directly, and the total cost of services shall not exceed Thirty Five Thousand Dollars ($35,000).

4. Employee Stock Ownership Plan. The Parties acknowledge the July 2019 board approval of an Employee Stock Ownership Plan ("***ESOP***") company contribution ("***ESOP Contribution***"), with any amount above the IRS contribution limits being paid in cash to employees ("***ESOP Contribution Payment***"). The Parties agree that Blanchard will be eligible for and will be paid the ESOP Contribution and ESOP Contribution Payment pursuant to the board's directive.

5. Vacation Payout. Regardless of whether Employee signs this Agreement, Employee will be paid for his accrued but unused vacation, subject to all applicable withholdings and deductions, on Panhandle's next regular pay date following the Termination Date.

6. Acknowledgements. Blanchard acknowledges that he does not have a pre- existing duty or obligation to enter into this Agreement. Blanchard acknowledges that if he does not (i) sign and accept the terms of this Agreement and (ii) execute a General Release now and again following his termination of employment, or if he violates the provisions of this Agreement, Panhandle has no obligation to make the Transition Payment or Severance Payment, in which case the release of claims provided and any promises made by Blanchard within this Agreement will be null and void. Panhandle acknowledges that if Blanchard signs and complies with the terms of this Agreement and each General Release that Panhandle is bound to make the Transition Payment or Severance Payment.

Blanchard's and his spouse's coverage under Panhandle health plans will end on the last day of the month following the Termination Date, September 30, 2019, unless he elects COBRA continuation coverage. By signing this Agreement, Blanchard acknowledges that he is solely responsible for electing COBRA continuation coverage and Panhandle acknowledges that it is responsible to provide Blanchard with all required notices regarding COBRA continuation coverage.

7. Counsel. Blanchard acknowledges that he has been represented by legal counsel, and his attorney reviewed each of these documents before he signed.

8. Acceptance. Blanchard acknowledges he has been provided twenty-one (21) days from the Effective Date to consider signing the General Release attached as Exhibit A, and will have twenty-one (21) days after the Termination Date to sign the General Release attached as Exhibit B. Blanchard may waive all or any part of either twenty-one (21) day period by signing and returning a General Release prior to the expiration of the applicable twenty-one (21) day period.

9. Revocation. If Blanchard decides to sign either General Release A or B, Blanchard may revoke that decision with regard to claims under the Age Discrimination in Employment Act at any time within seven (7) calendar days of the execution of each General Release by written notice to the Lead Independent Director of Panhandle. Blanchard understands that he cannot revoke his signature on a General Release at any time after that seven (7) day period. Blanchard also understands that the seven (7) day revocation period cannot be waived.

10. Actions. By signing this Agreement, Blanchard represents that he has not commenced and will not commence any action or complaint with any court, arbitrator or other body with jurisdiction over such disputes regarding his employment. Furthermore, if he has filed any such action, he promises to dismiss the same with prejudice. Nothing in this Agreement is intended to prohibit Blanchard from reporting possible violations of federal law or regulation to any governmental agency or entity, including but not limited to the Department of Justice, the Securities and Exchange Commission, Congress, and any agency Inspector General, or making other disclosures, including providing documents and other information, that are protected under the whistleblower provisions of federal law or regulation.

11. Non-Solicitation. Blanchard agrees that for a period of one (1) year following the Effective Date, Blanchard shall not directly, or through any other person or entity, solicit the purchase or sale of mineral interests, including but not limited to: mineral rights, leasehold rights, working interests, override interests or royalty interests ("Mineral Interests") from any Customer of Panhandle. Customer is defined as any entity or individual from which Panhandle has solicited, purchased, evaluated for purchase or is in the process of purchasing Mineral Interests. Blanchard, thru written request to the Lead Independent Director may seek an exception to this limitation. Blanchard further agrees that for a period of one (1) year following the Effective Date Blanchard shall not solicit, directly or indirectly, actively or inactively, the employees or independent contractors of Panhandle to become employees or independent contractors of another person or business.

12. Confidentiality of Information. As a further condition of this Agreement, Blanchard promises not to make any independent use of, or disclose to any other person or organization, or destroy any of the non-public, confidential, proprietary information or trade secrets of Panhandle except as expressly permitted in an email or other written communication from the Independent Lead Director of the Panhandle Board of Directors. This shall apply to any information which is of a special and unique value and includes, without limitation, both written and unwritten information relating to operations, business planning and strategies.

13. Commitment to Preserve Good Name. Furthermore, Blanchard will not disparage but will instead uphold and preserve the name and reputation of Panhandle and the names and reputations of the Board Members, trustees, officers, employees, and representatives of Panhandle

to any individuals, entities or the press or media. Panhandle and its Board Members, and officers of Panhandle will not disparage but will instead uphold and preserve the name and reputation of Blanchard to any individuals, entities or the press or media.

14. Arbitration. The Parties agree that any dispute, claim or controversy between the Parties which may arise out of or relate to Blanchard's employment relationship or this Agreement shall be settled by arbitration. Any arbitration shall be in accordance with the Rules of the American Arbitration Association and undertaken pursuant to the Federal Arbitration Act. Panhandle will pay all required filing fees, fees of the arbitrator and any other arbitration fees. Arbitration will be held in Oklahoma City, Oklahoma unless the Parties mutually agree on another location. The decision of the arbitrator will be enforceable in any court of competent jurisdiction. The Parties agree that punitive, liquidated or indirect damages shall not be awarded by the arbitrator unless such damages would have been awarded by a court of competent jurisdiction. Nothing in this agreement to arbitrate shall preclude Panhandle from obtaining injunctive relief from a court of competent jurisdiction prohibiting any on-going breaches of Blanchard of this Agreement.

15. Entire Agreement. This Agreement and each General Release constitute the entire agreement between Panhandle and Blanchard with regard to the parties' employer/employee relationship. Panhandle and Blanchard agree that there are no oral representations or understandings between them that are not contained within the written terms of these documents. Furthermore, the parties agree that this Agreement and each General Release may not be modified orally. To change the terms of this Agreement, both Blanchard and Panhandle must do so in writing. Finally, if any portion of this Agreement is held by a court to be invalid, or unenforceable, the remainder of the provisions shall remain in full force and effect and shall in no way be impaired, or invalidated.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement to be as of the date first above written.

Dated: September 20, 2019

/s/ Paul F. Blanchard
Paul F. Blanchard

Dated: September 30, 2019

Panhandle Oil and Gas, Inc.

By /s/ Mark T. Behrman

Its Lead Independent Director

Exhibit A

GENERAL RELEASE

In consideration of the agreement by PANHANDLE to make certain payments to me pursuant to the terms reflected in the Transition Agreement dated September 20, 2019 (the "*Transition* Agreement"), I hereby release and discharge PANHANDLE and its directors, trustees, employees, officers and benefit plans (hereafter collectively referred to as "PANHANDLE") from all claims, liabilities, demands, and causes of action, known or unknown, fixed or contingent, which I may have or claim to have against PANHANDLE either as a result of my employment with PANHANDLE and/or the severance of that relationship, and hereby waive any and all rights I may have with respect to and promise not to file a lawsuit to assert any such claims whether such claims are pursuant to an express or implied employment agreement or otherwise.

I understand that this release means that I have forfeited my right to sue PANHANDLE for any reason related to my past employment. This release will prevent me from asserting that I was discriminated against because of race, color, gender, age, religion, national origin, military status, workers' compensation claims, FMLA claims, sexual orientation, gender identity, genetic data, disability or any other status protected by law. This release will also prevent me from alleging that I was retaliated against for any reason, or that I was denied any money, benefits, leave, or any other term of employment.

This General Release includes, but is not limited to, claims arising under express or implied contracts of employment, Title VII of the Civil Rights Act of 1964, the Civil Rights Act of 1866, the Pregnancy Discrimination Act of 1978, the Equal Pay Act, the Civil Rights Act of 1991, the Age Discrimination in Employment Act, the Rehabilitation Act of 1973, the Americans With Disabilities Act, the Employee Retirement Income Security Act of 1974 and the Veterans Reemployment Rights Act (all as amended from time to time). This General Release also includes, but is not limited to, any rights I may have under the Older Workers Benefit Protection Act of 1990, the Worker Adjustment and Retraining Act of 1988, the Fair Labor Standards Act, the Family and Medical Leave Act, the Occupational Health and Safety Act, and any other federal, state and/or municipal statutes, orders or regulations pertaining to labor, employment and/or employee benefits.

This General Release also serves to waive all claims or rights available to me pursuant to the Uniformed Services Employment and Reemployment Rights Act of 1994 and the Veterans' Reemployment Rights Act, including, but not limited to, rights to reinstatement or reemployment. This General Release also applies to any claims or rights I may have growing out of the employer/employee relationship between me and PANHANDLE or any legal or equitable restrictions on PANHANDLE right not to continue an employment relationship with its employees, including any express or implied employment contracts, "public policy" claims, and to any claims I may have against PANHANDLE for fraudulent inducement or misrepresentation, defamation, wrongful termination or other retaliation claims in connection with workers' compensation or alleged "whistleblower" status or on any other basis whatsoever.

It is specifically agreed, however, that this General Release does not have any effect on any rights or claims I may have against PANHANDLE (i) which arise after the date I execute this General Release or (ii) on any vested rights I may have under any of PANHANDLE benefit plans or arrangements as of or after my last day of employment with PANHANDLE or (iii) on any of PANHANDLE obligations under the Transition Agreement. Nothing contained herein shall interfere with or waive my right to enforce or challenge the Transition Agreement in a court of competent jurisdiction or in arbitration, as further provided by the Transition Agreement. Furthermore, it is specifically agreed that nothing in the Transition Agreement or this General Release is intended to affect the rights and responsibilities of the Equal Employment Opportunity Commission or other governmental agency to enforce any statutes prohibiting employment discrimination or to interfere with my right to file a charge or participate in an investigation or proceeding conducted by any such agency. However, I do agree not to accept any relief or recovery from any charge or complaint filed against PANHANDLE with any such agency or court with regard to claims arising from my employment.

I have carefully reviewed and fully understand all the provisions of the Transition Agreement and this General Release. I have not relied on any representation or statement, oral or written, by PANHANDLE or any of its representatives, which is not set forth in those documents.

The Transition Agreement and this General Release set forth the entire agreement between me and PANHANDLE with respect to this subject. I understand that PANHANDLE's obligation to enter into the Transition Agreement and perform under the Transition Agreement is contingent not only on my execution of this General Release, but also on my continued compliance with my other obligations under the Transition Agreement.

I also acknowledge that PANHANDLE advised me to seek independent legal advice as to these matters, if I chose to do so. I hereby represent and state that I have taken such actions and obtained such information and independent legal advice that I believed were necessary for me to fully understand the effects and consequences of the Transition Agreement and this General Release prior to signing those documents.

I acknowledge that PANHANDLE gave me twenty-one (21) days to consider whether I wish to accept or reject the terms of the Transition Agreement in exchange for this General Release. I understand that if I sign and date this agreement prior to the expiration of the twenty-one (21) day period I hereby waive my rights to such twenty-one-day period and understand that my seven (7) day revocation period will begin on the date that I sign and return this General Release to PANHANDLE.

Dated this 20th day of September 2019.

By: /s/ Paul F. Blanchard
Paul F. Blanchard

Exhibit B

GENERAL RELEASE

In consideration of the agreement by PANHANDLE to make certain payments to me pursuant to the terms reflected in the Transition Agreement dated September 20, 2019 (the "*Transition* Agreement"), I hereby release and discharge PANHANDLE and its directors, trustees, employees officers and benefit plans (hereafter collectively referred to as "PANHANDLE") from all claims, liabilities, demands, and causes of action, known or unknown, fixed or contingent, which I may have or claim to have against PANHANDLE either as a result of my employment with PANHANDLE and/or the severance of that relationship, and hereby waive any and all rights I may have with respect to and promise not to file a lawsuit to assert any such claims whether such claims are pursuant to an express or implied employment agreement or otherwise.

I understand that this release means that I have forfeited my right to sue PANHANDLE for any reason related to my past employment. This release will prevent me from asserting that I was discriminated against because of race, color, gender, age, religion, national origin, military status, workers' compensation claims, FMLA claims, sexual orientation, gender identity, genetic data, disability or any other status protected by law. This release will also prevent me from alleging that I was retaliated against for any reason, or that I was denied any money, benefits, leave, or any other term of employment.

This General Release includes, but is not limited to, claims arising under express or implied contracts of employment, Title VII of the Civil Rights Act of 1964, the Civil Rights Act of 1866, the Pregnancy Discrimination Act of 1978, the Equal Pay Act, the Civil Rights Act of 1991, the Age Discrimination in Employment Act, the Rehabilitation Act of 1973, the Americans With Disabilities Act, the Employee Retirement Income Security Act of 1974 and the Veterans Reemployment Rights Act (all as amended from time to time). This General Release also includes, but is not limited to, any rights I may have under the Older Workers Benefit Protection Act of 1990, the Worker Adjustment and Retraining Act of 1988, the Fair Labor Standards Act, the Family and Medical Leave Act, the Occupational Health and Safety Act, and any other federal, state and/or municipal statutes, orders or regulations pertaining to labor, employment and/or employee benefits.

This General Release also serves to waive all claims or rights available to me pursuant to the Uniformed Services Employment and Reemployment Rights Act of 1994 and the Veterans' Reemployment Rights Act, including, but not limited to, rights to reinstatement or reemployment. This General Release also applies to any claims or rights I may have growing out of the employer/employee relationship between me and PANHANDLE or any legal or equitable restrictions on PANHANDLE rights not to continue an employment relationship with its employees, including any express or implied employment contracts, "public policy" claims, and to any claims I may have against PANHANDLE for fraudulent inducement or misrepresentation, defamation, wrongful termination or other retaliation claims in connection with workers' compensation or alleged "whistleblower" status or on any other basis whatsoever.

It is specifically agreed, however, that this General Release does not have any effect on any rights or claims I may have against PANHANDLE (i) which arise after the date I execute this General Release or (ii) on any vested rights I may have under any of PANHANDLE benefit plans or arrangements as of or after my last day of employment with PANHANDLE or (iii) on any of PANHANDLE obligations under the Transition Agreement. Nothing contained herein shall interfere with or waive my right to enforce or challenge the Transition Agreement in a court of competent jurisdiction or in arbitration, as further provided by the Transition Agreement. Furthermore, it is specifically agreed that nothing in the Transition Agreement or this General Release is intended to affect the rights and responsibilities of the Equal Employment Opportunity Commission or other governmental agency to enforce any statutes prohibiting employment discrimination or to interfere with my right to file a charge or participate in an investigation or proceeding conducted by any such agency. However, I do agree not to accept any relief or recovery from any charge or complaint filed against PANHANDLE with any such agency or court with regard to claims arising from my employment.

I have carefully reviewed and fully understand all the provisions of the Transition Agreement and this General Release. I have not relied on any representation or statement, oral or written, by PANHANDLE or any of its representatives, which is not set forth in those documents.

The Transition Agreement and this General Release set forth the entire agreement between me and PANHANDLE with respect to this subject. I understand that PANHANDLE's obligation to enter into the Transition Agreement and perform under the Transition Agreement is contingent not only on my execution of this General Release, but also on my continued compliance with my other obligations under the Transition Agreement.

I also acknowledge that PANHANDLE advised me to seek independent legal advice as to these matters, if I chose to do so. I hereby represent and state that I have taken such action and obtained information and independent legal advice that I believed was necessary for me to fully understand the effects and consequences of the Transition Agreement and this General Release prior to signing those documents.

I acknowledge that PANHANDLE gave me twenty-one (21) days to consider whether I wish to accept or reject the terms of the Transition Agreement in exchange for this General Release. I understand that if I sign and date this agreement prior to the expiration of the twenty-one (21) day period I hereby waive my rights to such twenty-one-day period and understand that my seven (7) day revocation period will begin on the date that I sign and return this General Release to PANHANDLE.

Dated this 1st day of October 2019.

By: /s/ Paul F. Blanchard
Paul F. Blanchard

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-221370) of Panhandle Oil and Gas Inc. and in the related Prospectus of our reports dated December 12, 2019, with respect to the financial statements of Panhandle Oil and Gas Inc., and the effectiveness of internal control over financial reporting of Panhandle Oil and Gas Inc., included in this Annual Report (Form 10-K) for the year ended September 30, 2019.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 12, 2019

EXHIBIT 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

December 12, 2019

Panhandle Oil and Gas Inc.
Grand Centre, Suite 300
5400 North Grand Blvd.
Oklahoma City, OK 73112

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, and to the inclusion of information taken from the reports listed below in the Panhandle Oil and Gas Inc. Annual Report on Form 10-K ("the 10-K"):

- Report as of September 30, 2019 on Reserves and Revenue of Certain Properties with interests attributable to Panhandle Oil and Gas Inc.;
- Report as of September 30, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Panhandle Oil and Gas Inc.; and
- Report as of September 30, 2017 on Certain Properties owned by Panhandle Oil and Gas Inc.

We further consent to the inclusion of our report of third party dated October 7, 2019, as Exhibit 99 in the 10-K.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATION

I, Chad L. Stephens III, certify that:

1. I have reviewed this annual report on Form 10- K of Panhandle Oil and Gas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Chad L. Stephens III
Chad L. Stephens III
Interim Chief Executive Officer
Date: December 12, 2019

Exhibit 31.2

CERTIFICATION

I, Robb P. Winfield, certify that:

1. I have reviewed this annual report on Form 10- K of Panhandle Oil and Gas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Robb P. Winfield
Robb P. Winfield
Chief Financial Officer
Date: December 12, 2019

Exhibit 32.1

Panhandle Oil and Gas Inc.
5400 North Grand Blvd. Suite #300
Oklahoma City, OK 73112

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
REGARDING PERIODIC REPORT CONTAINING
FINANCIAL STATEMENTS

I, Chad L. Stephens III, Interim Chief Executive Officer of Panhandle Oil and Gas Inc. (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify in connection with the Company's Annual Report on Form 10- K for the period that ended September 30, 2019, as filed with the Securities and Exchange Commission (the "Report") that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Chad L. Stephens III
Chad L. Stephens III
Interim Chief Executive Officer

December 12, 2019

Exhibit 32.2

Panhandle Oil and Gas Inc.
5400 North Grand Blvd. Suite #300
Oklahoma City, OK 73112

CERTIFICATION OF CHIEF FINANCIAL OFFICER
REGARDING PERIODIC REPORT CONTAINING
FINANCIAL STATEMENTS

I, Robb P. Winfield, Vice President and Chief Financial Officer of Panhandle Oil and Gas Inc. (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify in connection with the Company's Annual Report on Form 10- K for the period that ended September 30, 2019, as filed with the Securities and Exchange Commission (the "Report") that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robb P. Winfield
Robb P. Winfield
Vice President,
Chief Financial Officer and Controller

December 12, 2019

EXHIBIT 99

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

October 7, 2019

Panhandle Oil and Gas Inc.
5400 North Grand Boulevard
Suite 300
Oklahoma City, Oklahoma 73112

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of September 30, 2019, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Panhandle Oil and Gas Inc. (Panhandle) has represented it holds an interest. This evaluation was completed on October 7, 2019. The properties evaluated herein are located in Arkansas, New Mexico, North Dakota, Oklahoma, Texas, and Utah. Panhandle has represented that these properties account for 100 percent of Panhandle's net proved reserves as of September 30, 2019. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Panhandle.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after September 30, 2019. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Panhandle after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, transportation expenses,

capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, processing expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Panhandle to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Panhandle, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary nominal discount rate of 10 percent compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Panhandle and from public sources. Additionally, this information includes data supplied by IHS Markit Inc; Copyright 2019 IHS Markit Inc. In the preparation of this report we have relied, without independent verification, upon information furnished by Panhandle with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves estimated in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a)(1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report,

including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *Proved oil and gas reserves* – Proved oil and gas reserves are those quantities of oil and 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.
>
> > (i) The area of the reservoir considered as proved includes:
> > (A) The area identified by drilling and limited by fluid contacts, if any, and (B) 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 gas on the basis of available geoscience and engineering data.
> >
> > (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
> >
> > (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated 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.
> >
> > (iv) 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:
(A) 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 (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) 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 gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and 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.

(i) Reserves on undrilled acreage shall be 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.
>
> (ii) 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.
>
> (iii) 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, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and 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 (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. 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.

Based on the current stage of field development, production performance, the development plans provided by Panhandle, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. Proved undeveloped reserves were estimated for locations that have been permitted, are currently drilling, are drilled but not yet completed, or locations where the operator has indicated to Panhandle its intention to drill.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of

data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Panhandle from wells drilled through September 30, 2019, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through March 2019. Estimated cumulative production, as of September 30, 2019, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 6 months.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. All gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state in which the reserves are located. Gas reserves included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Panhandle. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Panhandle has represented that the oil, condensate, and NGL prices were based on West Texas Intermediate (WTI) pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Panhandle to the reference price of $57.85 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $54.40 per barrel of oil and condensate and $19.30 per barrel of NGL.

Gas Prices

Panhandle has represented that the gas prices were based on Henry Hub pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The gas prices were calculated for each property using differentials furnished by Panhandle to the reference price of $2.92 per million Btu and held constant thereafter. Btu factors provided by Panhandle were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves

over the lives of the properties was $2.481 per thousand cubic feet of gas.

Production Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Panhandle based on recent payments.

Operating Expenses, Transportation Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses and transportation expenses, provided by Panhandle and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2019 values, provided by Panhandle, and were not adjusted for inflation. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Panhandle for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of September 30, 2019, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of September 30, 2019		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved Developed	**1,863**	**1,747**	**67,713**
Proved Undeveloped	**517**	**226**	**12,561**
Total Proved	**2,380**	**1,973**	**80,274**

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of September 30, 2019, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	Total Proved (M$)
Future Gross Revenue	304,518	366,697
Production and Ad Valorem Taxes	17,377	21,113
Operating and Transportation Expenses	123,279	132,822
Capital and Abandonment Costs	1,918	1,918
Future Net Revenue	161,944	210,844
Present Worth at 10 Percent	86,814	110,396

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the September 30, 2019, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Panhandle. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Panhandle. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare this report of third party addressed to Panhandle dated October 7, 2019, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 35 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton