2022 ANNUAL REPORT

PHX MINERALS

Dear PHX Shareholders,

As we moved through 2021 into 2022, the post-Covid economy was running very hot (both domestically and globally). Supply chain issues could not meet demand, wage inflation was driving the employment landscape and lack of political will led to historic price inflation in the summer of 2022. This required the Fed to act quickly and decisively and begin raising interest rates at a historic pace in the second half of 2022. The predicted outcome is an economic slowdown with leading indicators threatening a potential recession in 2023, as evidenced by an inverted yield curve (short term rates higher than long term rates).

These events and the uncertainty they introduce have created high volatility in the markets, especially in the energy sector. Despite these headwinds, development activity in the oil and gas space remained steady during 2022. Oil prices increased 15% year-over-year and domestic natural gas prices were up over 50% with both commodities seeing dramatic price spikes over the summer of 2022. As we publish this, oil prices have abated as fears of a global recession spread. Volatility in natural gas prices persists as winter weather remains the central catalyst.

Rig counts for oil and gas drilling activity were up in 2022 from 2021 by 33% and 47%, respectively (still well short of pre-Covid levels). Despite this increased activity, year-over-year domestic oil volumes were up approximately 10% and natural gas volumes up a modest 2%.

The central issue that impacted the global energy markets was Russia's invasion of Ukraine and the subsequent restriction of oil and gas supplies from Russia. The long-term implication from this is the pivot to the west by most European countries to source their energy needs, especially Liquified Natural Gas (LNG), thereby, increasing the global demand for natural gas.

As a response to this increase in demand, the U.S. has focused on increasing its LNG export capacity. As of year-end 2022, the U.S. capacity for exporting LNG stood at approximately 13 bcf/d. Given the announced and proposed new projects in the U.S., it is estimated that this capacity will grow to 26.0 bcf/d by 2030, with a majority of this new capacity being built on the Texas/Louisiana coast.

Against this backdrop of industry volatility, we think it timely to reflect on the considerable transformation PHX Minerals has made since January of 2020. At that time, we initiated a corporate strategy change to become a minerals-only company. This strategy change was swift and included the installation of new management and technical team, a company name change and establishing relationships with a new energy bank and new third-party engineering firm. PHX's strong quarterly financial results have validated this transition, and we believe the future of PHX Minerals is bright.

Over the last three years ('20, '21 and '22), we have divested of $13.3 million legacy non-operating working interest assets, representing approximately 20% of our reserve base. Additionally, over the same three-year period, we have divested of almost 22,000 net mineral acres that generate no cash flow and represent no strategic value to the company for total cash consideration of $8.3 million. We have redeployed the sale proceeds, as well as allocating a material portion of our free cash flow, into acquiring higher-margin minerals in two core focus areas: the Haynesville, in East Texas and Louisiana, and the SCOOP, in Southern Oklahoma. This is the essence of high grading our asset base. When we made the aforementioned strategy change in 2020, the company's production volumes were approximately 61% non-op working interest (higher cost/lower margin) and 39% royalty volumes. At fiscal year-end 2022, PHX total corporate volumes are 35% nonop W.I. and 65% royalty volumes. We are anticipating that in 2023, PHX royalty volumes will represent over 90% of total corporate volumes, as nonop working interest will no longer be material. To highlight this point, PHX's royalty volumes will have increased roughly 2.3 times from what they were in Fiscal Year 2020. We will continue to focus on mainly clean natural gas assets, which currently represent greater than 75% of our production volumes.

Letter Continued on Inside Back Cover...

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

FORM 10-K

(Mark One)

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

For the fiscal year ended SEPTEMBER 30, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM TO**

Commission File Number 001-31759

PHX MINERALS INC.
(Exact name of Registrant as specified in its Charter)

DELAWARE	**73-1055775**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1320 South University Drive, Suite 720	
Fort Worth, TX	**76107**
(Address of principal executive offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to 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 Act. YES ☐ NO ☒

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. YES ☐ NO ☒

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☒ 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). YES ☒ NO ☐

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

Large accelerated filer	☐	Accelerated filer	☐
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. ☐

Indicate by check mark whether the Registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant, computed by using the $3.06 per share closing price of registrant's Common Stock, as reported by the New York Stock Exchange at March 31, 2022, the last day of the Registrant's most recently completed second fiscal quarter, was $67,013,392.

The number of shares of Registrant's Common Stock outstanding as of December 6, 2022, was 36,528,844.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of PHX Minerals Inc. (to be filed no later than 120 days after September 30, 2022) relating to the Annual Meeting of Stockholders, to be held on March 6, 2023, are incorporated into Part III of this Form 10-K.

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Special Note Regarding Forward Looking Statements

This Annual Report on Form 10-K for the fiscal year ended September 30, 2022 (this “Annual Report on Form 10-K”, this “Annual Report” or this “Form 10-K”) includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). 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 Annual Report on Form 10-K 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 natural gas and oil prices; the level of production on our properties; estimates of quantities of natural gas, oil and NGL 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 natural gas and oil. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K, 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 this 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 we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as 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, natural gas and oil industry and other defined terms used in this Annual Report:

ASC	Accounting Standards Codification.
ASU	Accounting Standards Update.
At-The-Market Program	Our Common Stock offering arrangement by which we may offer and sell, from time to time through or to Stifel, up to 3,000,000 shares of our Common Stock pursuant to an At-The-Market Equity Offering Sales Agreement, as amended, with Stifel as sales agent and/or principal.
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.
Bbl	Barrel.
Board	Board of directors of the Company.
BTU	British Thermal Units.
Common Stock	Common Stock, par value $0.01666 per share, of the Company.
completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas and/or crude oil.
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 natural gas or crude oil reservoir to the depth of a stratigraphic horizon known to be productive.
dry hole	Exploratory or development well that does not produce natural gas and/or crude oil in economically producible quantities.
EBITDA	Earnings before interest, taxes, depreciation and amortization (including impairment). EBITDA is a Non-GAAP measure.
ESOP	The PHX Minerals 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 natural gas or crude oil 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 costs.
GAAP	United States 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 gas and/or oil 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 natural gas and crude oil production.
Independent Consulting Petroleum Engineer(s)	DeGolyer and MacNaughton for the 2021 fiscal year and Cawley, Gillespie & Associates beginning in fiscal year 2022.
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	New York Mercantile Exchange.
OPEC	Organization of Petroleum Exporting Countries.
overriding royalty interest	An interest in the natural gas and oil produced under a lease, or the proceeds from the sale thereof, apportioned out of the working interest, to be received free and clear of all costs of development, operation or maintenance.
PDP	Proved developed producing.
play	Term applied to identified areas with potential natural gas and/or oil reserves.
production or produced	Volumes of natural gas, oil and NGL that have been both produced and sold.
proved reserves	The quantities of natural gas and crude oil, 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.
SOFR	The Secured Overnight Financing Rate.
Stifel	Stifel, Nicolaus & Company, Incorporated
unconventional	An area believed to be capable of producing natural gas and crude oil 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 gas and oil 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 natural gas and/or crude oil.
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,” “PHX,” “we,” “us” and “our” refer to PHX Minerals Inc., formerly known as Panhandle Oil and Gas Inc., and its predecessors and subsidiaries unless the context requires otherwise.

Fiscal year references

All references to years or fiscal years in this Annual Report, unless otherwise noted, refer to the Company’s fiscal year ended September 30. For example, references to 2022 mean the fiscal year ended September 30, 2022.

References to natural gas and oil properties

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

PART I

ITEM 1. Business

Overview

PHX Minerals Inc., a Delaware corporation, is a Fort Worth-based company focused on perpetual natural gas and oil mineral ownership in resource plays in the United States. Prior to a strategy change in 2019, the Company participated with a working interest on some of its mineral and leasehold acreage and as a result still holds legacy interests in leasehold acreage and non-operated working interests in natural gas and oil properties. In this Annual Report, we generally refer to such working interests and the related wells as "legacy" interests and wells.

The Company was originally founded as a cooperative in 1926, and its shares became publicly traded in 1979. Effective April 1, 2022, the Company changed its state of incorporation from Oklahoma to Delaware through a merger with a wholly owned subsidiary, which was conducted for such purpose (the "Reincorporation"). Other than the change in the state of incorporation, the Reincorporation did not result in any change in the business, physical location, management, assets, liabilities or net worth of the Company, nor did it result in any change in location of the Company's employees, including the Company's management.

Strategic Focus on Mineral Ownership

During fiscal year 2019, we made the strategic decision to focus on perpetual natural gas and oil mineral ownership and growth by acquiring minerals in our core focus areas and by developing our significant mineral acreage inventory. In accordance with this strategy, we have ceased taking any working interest positions on our mineral and leasehold acreage. During the three fiscal years ended September 30, 2022, we did not participate with a working interest in the drilling of any new wells. We believe that our strategy to focus on mineral ownership is the best path forward to provide our stockholders the greatest risk-weighted returns on their investments.

A "mineral fee" is an interest in real property in which the owner owns all of the rights to the minerals under the surface in perpetuity, as compared to a mineral lease in which the lessee's rights end at the expiration of the lease term or after production in paying quantities ceases with respect to the lease or the lease otherwise terminates in accordance with its terms. Generally, the mineral interest owner of a mineral fee interest reserves a non-cost bearing royalty interest upon the lease of such gas, oil, and other minerals to a gas and oil exploration and development company. Such companies lease such mineral interests from the fee mineral owner for a term with the expectation of producing natural gas and oil, thereby generating free cash flow from bonuses and royalties to the mineral interest owner.

As referenced above, our legacy leasehold interests, rather than our mineral interests, are non-operated working interests. These legacy non-operated working interests require us to contribute our proportionate share of the costs incurred by the operator in the development of such minerals. As discussed above and further below, since the end of 2019 and going forward, we no longer seek to participate with such working interests and are in the process of divesting legacy working interests and redeploying the proceeds into acquiring high quality mineral and royalty properties. Our producing mineral and leasehold properties are located primarily in Oklahoma, Texas, Louisiana, North Dakota and Arkansas.

Although a significant amount of our revenues is currently derived from the production and sale of natural gas, oil and NGL from our legacy working interests, the majority of our revenues is derived from royalties generated from the production and sale of natural gas, oil and NGL. These royalties are tied to our perpetual ownership of mineral acreage. Royalties are due and payable whenever the operator of such interest produces and sells natural gas, oil or NGL from wells located on our mineral acreage.

As of September 30, 2022, we owned approximately 244,739 perpetual mineral acres, as detailed in the table below:

Play	Net Acres	% Producing	% Leased But Not Producing	% Unleased
SCOOP	7,636	67%	7%	26%
STACK	5,802	90%	4%	6%
Arkoma Stack	10,604	70%	1%	29%
Haynesville	3,321	100%	0%	0%
Bakken /Three Forks	3,108	89%	0%	11%
Fayetteville	9,883	73%	0%	27%
Other	204,385	17%	2%	81%
Total:	**244,739**	**27%**	**2%**	**71%**

Approximately 29% of our net minerals are currently under lease with an operator of which 27% have a producing well. Additionally, approximately 71% of our net mineral position is currently unleased, providing the opportunity to generate additional cash flow from bonus payments and royalties without spending additional capital. We may also generate additional cash flows through opportunistically divesting unleased minerals. We also own working interests, royalty interests or both in 6,362 producing natural gas and oil wells and 172 wells in the process of being drilled or completed.

Exploration and development of our natural gas and oil properties are conducted by natural gas and oil exploration and production companies, which typically are larger, independent oil and gas operating companies. We do not operate any natural gas and oil properties. While we previously were an active working interest participant in wells drilled on our mineral and leasehold acreage, we now focus on growth through mineral acquisitions and through development of our significant mineral acreage inventory.

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

Our Business Strategy

Our principal business objective is to maximize stockholder value. At the end of 2019, we made the strategic decision to cease taking working interest positions on our mineral and leasehold acreage. Our focus since then has been on growth through mineral acquisitions and by developing our significant mineral acreage inventory in our core focus areas under high quality operators. We believe this is the best path to provide our stockholders the greatest risk-weighted returns on their investment. We intend to accomplish this objective by executing the following corporate strategies:

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

  - Increasing our mineral fee holdings by acquiring mineral acreage in our core focus areas of natural gas and oil resource plays with substantial undeveloped opportunities that meet or exceed our minimum return threshold;

  - Utilizing in-house geology and engineering expertise as a competitive advantage;

  - Proactively leasing or monetizing our unleased mineral holdings; and

  - High-grading our asset base by: (a) selectively divesting non-core minerals when the anticipated sales price exceeds our projected total value, (b) optimizing our leasehold and working interest positions through strategic sales and farmouts of such assets, and (c) redeploying proceeds from sales into our core focus areas.

- ***Maintain a Stable and Well Capitalized Balance Sheet.*** We plan to maintain a strong financial position through the following:

  - Maintaining a conservative amount of debt outstanding with ample liquidity to ensure our ability to successfully operate in all business and commodity environments; and

  - Hedging a portion of our future natural gas and oil prices to manage commodity price risk and protect our cash flow.

Our Business Strengths

We believe the following attributes position us to achieve our objectives:

- ***Focusing 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 our royalty revenue as a percentage of total revenue continues to increase. As of September 30, 2022, we owned approximately 244,739 net mineral acres located primarily in Oklahoma, Texas, North Dakota, Louisiana and Arkansas. We also own working interests, royalty interests or both in 6,362 producing natural gas and oil wells and 172 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 Haynesville, 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 natural gas, oil and NGL from these positions. During fiscal year 2022, production on our acreage averaged 26,328 Mcfed with approximately 78%, 12% and 10% of such volumes derived from the production of natural gas, oil and NGL, respectively.

- ***Material Undeveloped Mineral Position in Gas and Oil Producing Basins.*** Over 70% of our mineral fee position is currently unleased or not currently producing, providing us with the opportunity to generate additional cash flows from bonus payments and royalties without deploying additional capital. We may also generate additional cash flows through opportunistically divesting these unleased minerals.

- ***Stable and Flexible Financial Position.*** We maintain a stable and flexible financial position by actively managing our debt, cash and working capital. We hedge a portion of our production to manage commodity price risk and to protect our balance sheet and cash flow.

- ***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 members 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

We derive our revenue through bonus and royalty payments and from legacy working interests on our mineral and leasehold acreage. Our principal products from the production associated with our royalty and non-operated interests, in order of revenue generated, are natural gas, crude oil and NGL. These products are generally sold by well operators to various purchasers, including pipeline and marketing companies, which service the areas where the producing wells are located. Since we do not operate any of the wells in which we own an interest, we must rely on the operating expertise of numerous companies that operate the wells in which we own interests, including 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. We receive payments from natural gas, oil and NGL sales from the well operator or the contracted purchaser.

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

We enter into price risk management financial instruments (derivatives) to reduce our exposure to short-term fluctuations in the price of natural gas and oil and to protect our return on investments. The derivative contracts apply only to a portion of our natural gas and oil production, provide only partial price protection against declines in natural gas and oil prices and may limit the benefit of future increases in natural gas and oil prices. Please see Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts we enter into.

Competitive Business Conditions

The oil and natural gas industry is highly competitive, particularly with respect to attempting to acquire additional fee mineral interests and natural gas, oil and NGL reserves. Many factors beyond our control affect our competitive position. Some of these factors include: the quantity and price of foreign oil imports; domestic supply and deliverability of natural gas, oil and NGL; changes in prices received for natural gas, oil and NGL production; business and consumer demand for refined natural gas, oil products and NGL; and the effects of federal, state and local regulation of the exploration for, production of and sales of natural gas, oil and NGL (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.

We do not operate any of the wells in which we have an interest; rather, we rely on operating companies with greater resources, staff, equipment, research and experience for both drilling and production of gas and oil wells. Our business strategy is to use our stable and flexible financial position, coupled with our own geologic and economic evaluations, to acquire new mineral acreage and to lease or farmout our mineral and leasehold acreage interests. We believe this strategy allows us 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

Our natural gas, oil and NGL production is sold, in most cases, through our lessees or well operators to numerous different purchasers. The loss of certain major purchasers of natural gas, oil and NGL production could have a material adverse effect on our ability to produce and sell, through our lessees or well operators, natural gas, oil and NGL production. The following table shows sales to major purchasers, by percentage, through various operators/purchasers during 2022, 2021, and 2020.

	2022	2021	2020
Company A	10%	14%	23%
Company B	5%	7%	6%

Regulation of the Natural Gas and Oil Industry

General

As the owner of mineral fee interests and non-operating working interests, we do not have any employees or contractors actually operating 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 natural gas and oil properties, including our current operators. Since we do not operate any wells in which we have interests, actual compliance with many laws and regulations is controlled by the well operators, and we are responsible only for our proportionate share of the costs, if any, involved on wells in which we own a working interest.

Natural gas and oil 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 natural gas and oil exploration and production industry as a whole, companies that operate our interests 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 we may be partially insulated from compliance costs applicable to our operator-lessees, we may still be indirectly impacted by operator regulations because our revenue stream depends on operators complying with applicable laws and regulations that govern the production of natural gas, oil and NGL.

Regulation of Drilling and Production

The production of natural gas and oil 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 provide for reporting requirements concerning operations. Additionally, the state regulatory agencies where we own mineral and leasehold interests have enacted regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that can be produced from wells and to limit the number of wells or the locations 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 natural gas, oil and NGL within the applicable jurisdictions.

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 has enacted price controls in the past and 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.

Natural gas and oil 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 gas and oil production has been left to state regulatory boards or agencies in those jurisdictions where there is significant natural gas and oil production, with limited direct regulation by such federal agencies as the Environmental Protection Agency (the "EPA"). However, there are various regulations issued by the 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 natural gas and oil 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 we do not operate any wells in which we own an interest, actual compliance with environmental laws is controlled by the well operators, and we are only responsible for our proportionate share of the costs for wells in which we own a working interest. As such, we have no knowledge of any instances of non-compliance with existing laws and regulations. We maintain insurance coverage at levels customary in the industry, but we are not fully insured against all environmental risks.

Taxes

Our natural gas and oil properties are subject to various taxes, such as gross production taxes and, in some cases, ad valorem taxes, which we pay on minerals we own.

Employees

At September 30, 2022, we had 22 full-time employees, including our executive officers, and did not have any part-time employees.

Executive Officers

Chad L. Stephens, age 67, has served as our President and Chief Executive Officer since January 2020. Mr. Stephens served as Interim CEO from October 2019 to December 2019, and he has served as a Director of the Company since September 2017. Prior to joining the Company, Mr. Stephens held several positions at Range Resources Corporation from 1990 through his retirement in 2018, where he served as Senior Vice President – Corporate Development.

Ralph D’Amico, age 47, has served as our Chief Financial Officer, Vice President and Corporate Secretary since March 2020 and served as Vice President – Business Development from January 2019 through February 2020. Prior to joining the Company, Mr. D’Amico served as a Managing Director focused on energy at Stifel Nicolaus and Seaport Global Securities and held various other energy investment banking positions at Jefferies, Friedman Billings Ramsey and Salomon Smith Barney prior to then.

Danielle D. Mezo, age 35, has served as our Vice President of Engineering since January 2022 and as Director of Engineering from November 2020 through December 2021. Prior to joining the Company, she held various reservoir engineering, reserves, acquisitions, corporate planning, and management positions at SandRidge Energy and has 13 years of experience in the oil and gas industry.

Chad D. True, age 37, has served as our Vice President of Accounting and Assistant Corporate Secretary since January 2022 and as Director of Accounting and Assistant Corporate Secretary from May 2020 through December 2021. Prior to joining the Company, he held various audit and accounting positions at Grant Thornton LP and Wexford Capital LP and has more than 14 years of accounting experience.

Kenna D. Clapp, age 36, has served as our Director of Land since November 2020. Prior to joining the Company, she held various land positions at Chesapeake Energy and has more than 10 years of land experience across multiple basins including Haynesville, Eagleford, Mid-Continent and Barnett.

Carl Vandervoort, age 40, has served as our Director of Geology since January 2021. Prior to joining the Company, he managed Rainmaker Resources, a buy-side consulting company for private equity groups and private equity portfolio companies. Prior to that, Mr. Vandervoort was the Exploration Manager at Zenergy, Inc., an Apollo Management portfolio company.

Corporate Office

Our corporate headquarters are located at 1320 South University Drive, Suite 720, Fort Worth, TX 76107. All geology, engineering and accounting employees are located at 1601 NW Expressway, Suite 1100, Oklahoma City, OK 73118. Our telephone number is (405) 948-1560 and our website is **www.phxmin.com**.

Available Information

We make available free of charge on our website (www.phxmin.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 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 "Governance Library" section under the "Corporate Governance" section of our website our Code of Ethics & Business Practices, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines, and Audit Committee, Governance and Sustainability Committee and Compensation Committee Charters, each of 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: PHX Minerals Inc., Attn: Chad True, 1601 NW Expressway, Suite 1100, Oklahoma City, OK 73118.

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 our business and future prospects. If any of the following risk factors should occur, our financial condition could be materially impacted, and the holders of our securities could lose part or all of their investment in the Company. As the owner of mineral fee interests and non-operating working interests, we do not operate any natural gas and oil properties, and we do not have any employees or contractors in the field. As such, the risks associated with natural gas and oil operations 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 our Company and our 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 natural gas and oil 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 natural gas, oil and NGL impact the prices we realize on the sale of these commodities and, in turn, materially affect our financial results. Our revenues, operating results, cash available for distribution and the carrying value of our natural gas and oil properties depend significantly upon the prevailing prices for natural gas, oil and NGL. Natural gas, oil and NGL prices have historically been, and will likely continue to be, volatile. The prices for natural gas, oil and NGL 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 natural gas, oil and NGL, both domestically and abroad;
- the impacts and effects of public health crises, pandemics and epidemics, such as the COVID-19 pandemic;
- 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;
- conservation and environmental protection efforts;
- the level of imports and exports of natural gas, oil and NGL;

- political instability or armed conflicts in major natural gas and oil producing regions;
- actions taken by OPEC or other major natural gas, oil and NGL producing or consuming countries;
- technological advancements affecting energy consumption and energy supply;
- the level of prices and expectations about future prices of natural gas and oil;
- the level of global natural gas and oil exploration and production;
- the cost of exploring for, developing, producing and delivering natural gas and oil;
- 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 OPEC to agree to and maintain oil price and production controls;
- speculative trading in natural gas and crude oil derivative contracts;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- the price and availability of, and competition from, 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;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the U.S., such as the conflict between Ukraine and Russia;
- the proximity, cost, availability and capacity of natural gas and oil 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 natural gas, oil and NGL price movements with any certainty. If the prices of natural gas, oil and NGL decline, our operations, financial condition and level of expenditures for the development of our natural gas, oil and NGL reserves may be materially and adversely affected. Lower natural gas, oil and NGL 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 natural gas, oil and NGL 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 natural gas, oil and NGL price movements with any certainty. Natural gas, oil and NGL prices continued to fluctuate in fiscal year 2022, with the COVID-19 pandemic continuing to contribute to volatility and uncertainty. Our financial position, results of operations, access to capital and the quantities of natural gas, oil and NGL that may be economically produced would be negatively impacted if natural gas, oil and NGL prices were low for an extended period of time. The ways in which low prices could have a material negative effect include the following:

- significantly decrease the number of wells operators drill on our 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

- we may incur a reduction in the borrowing base on our credit facility.

The COVID-19 pandemic may adversely affect our business, financial condition and results of operations.

The COVID-19 pandemic ("COVID-19") created significant uncertainty and economic disruption, as well as heightened volatility in the prices of oil and natural gas. The negative impact on worldwide demand for oil and natural gas resulting from COVID-19 led to a precipitous decline in oil prices, further exacerbated by the early March 2020 failure by OPEC+ to reach an agreement over proposed oil production cuts and global storage considerations. Although OPEC+ subsequently agreed to cut oil production, crude oil prices remained depressed as a result of an increasingly utilized global storage network and the decrease in crude oil demand due to COVID-19. Since then, oil and natural gas prices have risen, but such prices are expected to continue to be volatile as a result of multiple factors, including COVID-19 and related measures taken by governments around the world, and as changes in oil and natural gas inventories, oil demand and economic performance are reported. Although government response measures to COVID-19 have generally relaxed, the ultimate impact of this pandemic is uncertain and subject to change. The extent of the impact of COVID-19 on our operational and financial performance will depend on future developments, including the reemergence of widespread COVID-19 infections, COVID-19 variants, the pandemic's severity, actions to contain the disease or mitigate its impact and the effectiveness of treatments and vaccines, all of which are highly uncertain and cannot be predicted with certainty at this time. Declines in oil prices due to COVID-19 could result in the events discussed in the immediately preceding risk factor, which could have a material adverse effect on our business and financial results. We are unable to predict the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments, including the pandemic's ongoing effect on the demand for oil and natural gas and the response of the overall economy and the financial markets after the pandemic and response measures come to an end, the timing of which remains highly uncertain.

The conflict in Ukraine and related price volatility and geopolitical instability could negatively impact our business.

In late February 2022, Russia launched significant military action against Ukraine. The conflict has caused, and could intensify, volatility in natural gas, oil and NGL prices, and the extent and duration of the military action, sanctions and resulting market disruptions could be significant and could potentially have a substantial negative impact on the global economy and/or our business for an unknown period of time. There is evidence that the increase in crude oil prices during the first half of calendar year 2022 was partially due to the impact of the conflict between Russia and Ukraine on the global commodity and financial markets, and in response to economic and trade sanctions that certain countries have imposed on Russia. Any such volatility and disruptions may also magnify the impact of other risks described in this "Risk Factors" section.

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

We have elected to utilize the successful efforts method of accounting for our natural gas and oil 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 natural gas, oil and NGL volumes produced to total proved or proved developed reserves) as natural gas, oil and NGL are produced.

All long-lived assets, principally our natural gas and oil properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset on our books may be greater than our future net cash flows. The need to test a property for impairment may result from declines in natural gas, oil and NGL sales prices or unfavorable adjustments to natural gas, oil and NGL 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, we 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 11 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 developing our existing inventory of mineral acreage and acquiring additional mineral interests. Failure to develop our existing inventory of mineral acreage and to acquire additional mineral interests will cause reserves and production to decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Our proved reserves will decline materially as reserves are produced except to the extent that we acquire additional mineral interests on properties containing proved reserves and our lessees or well operators conduct additional successful exploration and development drilling, successfully apply new technologies or identify additional behind-pipe zones (different productive zones within existing producing well bores) or secondary recovery reserves.

Drilling for natural gas and oil 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. We rely 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 natural gas, oil or NGL 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 natural gas, oil or NGL produced from the wells.

Competition for acquisitions of mineral interests 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 or assets into our existing operations. The process of integrating acquired businesses or assets 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 mineral interest 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 acquisition of additional mineral and royalty interests that we complete will be subject to substantial risks.

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 natural gas and oil 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 natural gas, oil and NGL with precision. Natural gas, oil and NGL reserve engineering requires subjective estimates of underground accumulations of natural gas, oil and NGL 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 Engineer must make various assumptions with respect to many matters that may prove to be incorrect, including:

- future natural gas, oil and NGL 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 our natural gas, oil and NGL reserves. Please read Item 2 – "Properties – Proved Reserves" and Note 16 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 natural gas, oil and NGL 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.

Debt level and interest rates may adversely affect our business.

On September 1, 2021, we entered into a four-year Credit Agreement (as amended, the "Credit Agreement") with certain lenders and Independent Bank, as Administrative Agent and Letter of Credit Issuer (as defined in the Credit Agreement). The Credit Agreement replaced our prior revolving credit facility set forth in the Amended and Restated Credit Agreement dated as of November 25, 2013, as amended, among the Company, each lender party thereto, and BOKF, NA dba Bank of Oklahoma, as administrative agent, which we repaid in full and terminated. As of September 30, 2022, we had a balance of $28,300,000 drawn on our credit facility set forth in the Credit Agreement (the "Credit Facility). The Credit Facility's borrowing base is set at $50,000,000. All obligations under the Credit Agreement are secured, subject to permitted liens and other exceptions, by a first-priority security interest on substantially all of our personal property and at least 80% of the total value of the proved, developed and producing Oil and Gas Properties (as defined in the Credit Agreement) owned by the Company.

Should we incur additional indebtedness under the Credit Facility to fund capital projects or for other reasons, there is a risk this could adversely affect 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 Credit 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 under the Credit Facility will limit funds available for other purposes; and

- changes in prevailing interest rates may affect our capability to meet our interest payments, as the Credit Facility bears interest at floating rates.

The borrowing base of our Credit Facility is subject to periodic redetermination and is based in part on natural gas, oil and NGL prices. A lowering of our borrowing base because of lower natural gas, oil or NGL prices, or for other reasons, could require us to repay indebtedness in excess of the 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 natural gas and oil 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.

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 natural gas, oil and NGL 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 our ability to conduct our 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.

Our derivative activities may reduce the cash flow received for natural gas and oil sales.

In order to manage exposure to price volatility on our natural gas and oil production, we currently, and may in the future, enter into natural gas and oil derivative contracts for a portion of our expected production. Natural gas and oil price derivatives may limit the cash flow we actually realize and therefore reduce our ability to fund future projects. None of our natural gas and oil 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 natural gas and oil. The fair value of our natural gas and oil derivative instruments outstanding as of September 30, 2022, was a net liability of $8,561,191.

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 natural gas and oil production to commodity price changes and could have a negative effect on our ability to fund future acquisitions.

Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 and 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding derivative contracts.

There are inherent limitations in all control systems, and misstatements due to error or fraud could occur and not be detected.

The ongoing internal control provisions of Section 404 of the Sarbanes-Oxley Act of 2002 require us to identify material weaknesses in internal control over financial reporting, which is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with GAAP. Our management, including our principal executive officer and principal financial officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud in our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of the company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur in the future and not be detected.

In addition, discovery and disclosure of a material weakness, such as the material weakness we previously discovered and disclosed, by definition, could have a material adverse impact on our financial statements. Such an occurrence could negatively affect our business and affect how our stock trades. This could, in turn, negatively affect our ability to access public equity or debt markets for capital.

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

Companies that operate wells in which we own a working interest are subject to extensive federal, state and local regulation. We, as a working interest owner, are 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. In particular, changes in law or regulation related to hydraulic fracturing or greenhouse gases could potentially increase capital, compliance and operating costs significantly, as well as halt or delay the further development of oil and gas reserves on our properties.

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.

Certain beneficial provisions within the Tax Cuts and Jobs Act passed in December 2017 are set to be reduced beginning in 2023 and beyond, such as a reduction in the amount of immediate bonus depreciation available for qualified property placed into service.

The Inflation Reduction Act of 2022 (the "IRA"), which was signed into law in August 2022, includes several provisions that are specifically applicable to corporations. The IRA includes an annual 15% minimum tax on corporations that have "average annual adjusted financial statement income" in excess of $1 billion over a three year period. The IRA also includes a 1% tax on publicly traded corporations on the fair market value of stock repurchased during any taxable year. Such tax applies to the extent such buybacks exceed $1 million during such year, which buyback value may be offset by other stock issuances.

Additionally, 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 material 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 natural gas, oil and NGL produced within the state. Under Oklahoma law, the gross production tax rate on the first three years of a horizontal well's production is 5.2% and 7% thereafter. Future changes to Oklahoma production taxes could affect the profitability of wells producing natural gas, oil and NGL in Oklahoma.

Hydraulic Fracturing and Water Disposal

The vast majority of natural gas and oil 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 we own an interest. Hydraulic fracturing is a process that involves pumping water, sand and additives at high pressure into rock formations to stimulate natural gas and oil 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 gas and oil reserves on our properties. Though the Biden administration has not proposed the outright ban of hydraulic fracturing, the administration has proposed significant regulations regarding methane emissions that could potentially affect new and existing wells, including those that are hydraulically fractured. The proposed methane rule is discussed in more detail in the Climate Change section, below.

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 natural gas and oil, 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 gas and oil 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 EPA issued greenhouse gas monitoring and reporting regulations that cover natural gas and oil 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 resulted in an exit in November 2020. While the U.S. officially exited the Paris Agreement in November of 2020, the Biden administration immediately rejoined the Paris Agreement after taking office in January of 2021. On January 20, 2021, President Biden signed an executive order triggering a 30-day process to re-enter the agreement.

More recently, the EPA issued a proposed rule to regulate methane emissions from the oil and gas industry. If adopted, states will have authority to incorporate the emission guidelines proposed by EPA or to adopt their own standards that achieve the same degree of emission limitations. The proposed rule applies to the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments. If adopted, these rules would result in additional operating costs, such as costs to purchase and operate emissions controls or lower emitting equipment and costs to implement monitoring requirements.

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

We cannot control activities on our properties.

We do not operate any of the properties in which we have an interest and have 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:

- our return on capital used in drilling or property acquisition;
- our production and reserve growth rates;
- capital required to workover or recomplete wells;

- success and timing of drilling, development and exploitation activities on our 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 our financial position and results of operations.

The natural gas and oil 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 natural gas and oil 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;
- natural gas, oil and NGL 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.

We maintain 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 us against all risks. For example, we do 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 our 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 natural gas or oil 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 natural gas, oil and NGL 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 natural gas, oil and NGL 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 our wells, resulting in an adverse effect on our financial condition, cash flow and operating results.

The marketability of natural gas and oil 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' natural gas and oil 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 as 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.

We may be negatively impacted by inflation.

Increases in inflation could have an adverse effect on us. Current and future inflationary effects may be driven by, among other things, supply chain disruptions and governmental stimulus or fiscal policies, and geopolitical instability, including the ongoing conflict between the Ukraine and Russia. Continuing increases in inflation could increase our costs of labor and other costs related to our business, which could have an adverse impact on our business, financial position, results of operations and cash flows. Inflation has also resulted in higher interest rates in the U.S., which could increase our cost of debt borrowing in the future.

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 U.S. markets contribute to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of natural gas, oil and NGL, 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 natural gas, oil and NGL 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 natural gas and oil.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas and oil. The impact of the changing demand for natural gas and oil 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.

We filed a shelf registration statement on Form S-3 on October 19, 2020, and amendments thereto on December 10, 2020, February 8, 2021, and February 19, 2021, which the SEC declared effective on February 24, 2021 (the "February 2021 S-3"). The February 2021 S-3 allows us to issue up to $75 million in securities including Common Stock, preferred stock, debt securities, warrants and units, and is intended to provide us with increased financial flexibility and more efficient access to the capital markets. On August 25, 2021, we entered into an At-The-Market Equity Offering Sales Agreement with Stifel, as sales agent and/or principal, pursuant to which we may offer and sell, from time to time through or to Stifel, up to 3,000,000 shares of our Common Stock under the February 2021 S-3. We also issue shares of our Common Stock in private transactions from time to time. During fiscal year 2022, we issued 1,519,481 shares of Common Stock in a private transaction on December 1, 2021, as consideration for the acquisition of certain mineral and royalty assets. These shares were registered with the SEC through the filing of a resale registration statement on Form S-3, which the SEC declared effective on January 27, 2022.

We cannot predict the effect, if any, that market sales of these securities or the availability of the securities will have on the prevailing market price of our Common Stock 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.

As of September 30, 2022, we were authorized to issue an aggregate of 54,010,500 shares of capital stock, consisting of 54,000,500 shares of Common Stock and 10,000 shares of preferred stock, par value $0.01666 per share ("Preferred Stock"), of which 36,528,844 shares of Common Stock and no shares of Preferred Stock were issued and outstanding on December 6, 2022. Future issuances of our Common Stock or Preferred Stock, or other securities convertible into our Common Stock or Preferred 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 $0.02 per share, and we have paid a quarterly dividend ranging from $0.01 per share or $0.04 per share for the past three 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 us 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.

If we cannot meet the NYSE continued listing requirements, the NYSE may delist our Common Stock.

Our Common Stock is currently listed on the NYSE. In the future, if we are unable to meet the continued listing requirements of the NYSE, including, among other things, (i) the requirement of maintaining a minimum average closing price of $1.00 per share over a consecutive 30 trading-day period and (ii) the requirement of maintaining an average market capitalization of not less than $50 million over a 30 trading-day period with, at the same time, stockholders' equity not less than $50 million, we would fall below compliance standards and risk having our Common Stock delisted. In addition, in the event of an abnormally low share price of our

Common Stock and/or we fail to maintain an average market capitalization of at least $15 million over a 30-trading day period, we would be subject to immediate delisting under the NYSE's rules without any opportunity to cure. A delisting of our Common Stock could negatively impact us by, among other things, the following:

- causing our shares to be transferred to a more limited market than the NYSE, which could affect the market price, trading volume, liquidity and resale price of such shares;
- reducing the number of investors, including institutional investors, willing to hold or acquire our Common Stock, which could negatively impact our ability to raise equity;
- decreasing the amount of news and analyst coverage relating to us;
- limiting our ability to issue additional securities, obtain additional financing or pursue strategic restructuring, refinancing or other transactions; and
- impacting our reputation and, as a consequence, our business.

ITEM 1B. Staff Comments

None

ITEM 2. Properties

General Background

We are focused on perpetual natural gas and oil 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 natural gas and oil properties.

At September 30, 2022, our principal properties consisted of (i) perpetual ownership of 244,739 net mineral acres, held principally in Oklahoma, Texas, Louisiana, North Dakota and Arkansas; (ii) leases on 16,260 net acres primarily in Oklahoma; and (iii) working interests, royalty interests or both in 6,362 producing natural gas and oil wells and 172 wells in the process of being drilled or completed.

Management's Business Strategy Related to Properties

Our primary focus continues to be on perpetual natural gas and oil mineral ownership and growth through mineral acquisitions and the development of our significant mineral acreage inventory in our core focus areas. In accordance with this strategy, we no longer participate in new development on our mineral or leasehold acreage with a cost-bearing working interest. We believe that our strategy to focus on mineral ownership is the best path to giving our stockholders the greatest risk-weighted returns on their investments.

Our goal is to increase stockholder value through the active management of our fee mineral and leasehold assets. We continue to grow our mineral fee holdings by acquiring mineral acreage, in the core areas of resource plays with substantial undeveloped opportunities, that meets or exceeds our corporate return threshold. We have an active program in place focused on leasing open acreage to generate additional lease bonus revenue and future royalty revenue. We also generate additional cash flows through opportunistically divesting unleased minerals.

Title to Properties

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. In recent years, a few insignificant challenges have been made against our fee title to our 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, 2022.

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 Unleased (3)	Gross Acres Unleased (3)
Oklahoma	110,241	1,067,706	47,953	440,221	3,482	29,345	58,807	598,139
Texas	33,077	276,069	5,092	74,703	2,053	12,411	25,931	188,955
Louisiana	2,299	32,574	2,299	32,574	-	-	-	-
North Dakota	14,304	90,362	2,774	26,750	-	-	11,530	63,613
Arkansas	11,754	55,417	7,227	32,157	9	80	4,518	23,180
Other	73,064	257,585	1,076	7,700	68	400	71,920	249,485
Total:	**244,739**	**1,779,713**	**66,421**	**614,105**	**5,612**	**42,236**	**172,706**	**1,123,372**

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

Leases

The following table reflects our net mineral acres leased from others, lease expiration dates, and net leased acres held by production related to leasehold as of September 30, 2022.

		Net Acres Expiring					
State	Net Acres	2022	2023	2024	2025	2026	Net Acres Held by Production
Oklahoma	11,487	-	-	-	-	-	11,487
Texas	2,200	-	-	-	-	-	2,200
Other	1,083	-	-	-	-	-	1,083
TOTAL	14,770	-	-	-	-	-	14,770

The following table reflects our net mineral acres leased from others, lease expiration dates, and net leased acres held by production related to our overriding royalty interests as of September 30, 2022.

		Net Acres Expiring					
State	Net Acres	2022	2023	2024	2025	2026	Net Acres Held by Production
Louisiana	173	-	-	-	-	-	173
Oklahoma	1,288	-	-	-	-	-	1,288
Texas	29	-	-	-	-	-	29
TOTAL	1,490	-	-	-	-	-	1,490

Proved Reserves

Summary of Proved Reserves

The following tables summarize estimates of total and royalty only proved reserves of natural gas, oil and NGL held by the Company as of September 30, 2022, 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 6,362 wells, which are predominately located in the Mid-Continent region. Other than this Annual Report, our reserve estimates are not filed with any federal agency.

Summary of Proved Natural Gas and Oil Reserves

	Natural Gas (Mcf)	Oil (Bbl)	NGL (Bbl)	Total Proved (Mcfe)
Net Proved Developed Reserves				
September 30, 2022	50,304,185	1,275,853	1,698,046	68,147,579
September 30, 2021	60,287,881	1,439,860	1,467,092	77,729,593
September 30, 2020	40,924,083	1,148,989	1,135,864	54,633,201
Net Proved Undeveloped Reserves				
September 30, 2022	11,933,021	106,924	64,637	12,962,387
September 30, 2021	4,664,787	64,980	34,761	5,263,233
September 30, 2020	1,448,690	184,668	83,993	3,060,656
Net Total Proved Reserves				
September 30, 2022	62,237,206	1,382,777	1,762,683	81,109,966
September 30, 2021	64,952,668	1,504,840	1,501,853	82,992,826
September 30, 2020	42,372,773	1,333,657	1,219,857	57,693,857

Summary of Proved Natural Gas and Oil Royalty Reserves

	Natural Gas (Mcf)	Oil (Bbl)	NGL (Bbl)	Total Proved (Mcfe)
Net Proved Developed Royalty Interest Reserves				
September 30, 2022	32,055,133	607,727	685,166	39,812,491
September 30, 2021	23,978,345	667,457	527,142	31,145,939
September 30, 2020	14,559,704	526,934	408,407	20,171,750
Net Proved Undeveloped Royalty Interest Reserves				
September 30, 2022	11,933,021	106,924	64,637	12,962,387
September 30, 2021	4,664,782	64,979	34,762	5,263,228
September 30, 2020	1,448,696	184,666	83,999	3,060,686
Net Total Proved Royalty Interest Reserves				
September 30, 2022	43,988,154	714,651	749,803	52,774,878
September 30, 2021	28,643,127	732,436	561,904	36,409,167
September 30, 2020	16,008,400	711,600	492,406	23,232,436

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

For the year ended September 30, 2022, our net total proved reserves decreased by 1.9 Bcfe, as compared to September 30, 2021. The decrease in total proved reserves from September 30, 2021 to September 30, 2022 is attributable to a combination of the following factors:

- The sale of 17.6 Bcfe proved developed, consisting predominately of working interest properties in the Fayetteville Shale play in Arkansas and the Arkoma Stack play and Western Anadarko Basin in Oklahoma.

- Production of 9.6 Bcfe from our natural gas and oil properties.

- Negative performance revisions of 3.3 Bcfe (comprised of all proved developed), principally due to steep declines following workovers on high working interest Woodford Shale wells in the Arkoma Stack play in Oklahoma and steeper declines on Bossier Shale wells drilled in the last two years as compared to Haynesville Shale wells in the Haynesville play of Texas.

- The acquisition of 15.6 Bcfe, predominately of royalty interest properties in the active drilling programs of the Haynesville Shale play in east Texas and western Louisiana and the Mississippi and Woodford Shale intervals in the SCOOP play in the Ardmore basin of Oklahoma, of which 7.0 Bcfe were proved developed and 8.6 Bcfe were proved undeveloped.

- Positive pricing revisions of 8.1 Bcfe of proved developed revisions due to natural gas and oil wells extending their economic limits later than was projected in 2021 due to higher commodity prices.

- Reserve extensions, discoveries and other additions of 4.9 Bcfe (comprised of 1.7 Bcfe proved developed and 3.2 Bcfe proved undeveloped reserves) principally resulting from: (i) our royalty interest ownership in the ongoing development of unconventional natural gas, utilizing horizontal drilling, in the Haynesville Shale play of East Texas and Western Louisiana; and (ii) our royalty interest ownership in the ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma.

Proved Undeveloped Reserves

The following details the changes in proved undeveloped reserves for fiscal year 2022 (Mcfe):

Beginning proved undeveloped reserves	5,263,233
Proved undeveloped reserves transferred to proved developed	(4,132,227)
Revisions	63,036
Extensions and discoveries	3,164,434
Sales	-
Purchases	8,603,911
Ending proved undeveloped reserves	12,962,387

During fiscal year 2022, total net PUD reserves increased by 7.7 Bcfe. In fiscal year 2022, a total of 4.1 Bcfe (79% of the beginning balance) was transferred to proved developed. The remaining balance of approximately 11.8 Bcfe (225% of the beginning balance) of positive revisions to PUD reserves consist of acquisitions of 8.6 Bcfe in the Haynesville Shale in Texas and Louisiana and Meramec and Woodford SCOOP play in Oklahoma and additions and extensions of 3.2 Bcfe within the active drilling program areas of (i) the Haynesville Shale in Texas and Louisiana, (ii) the SCOOP Meramec and Woodford in Oklahoma, (iii) the STACK Meramec and Woodford in Oklahoma and (iv) the Bakken in North Dakota.

We anticipate that all our 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.

Estimated Future Net Cash Flows

Set forth below are estimated future net cash flows with respect to our 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. We follow 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 natural gas, oil and NGL as of September 30, 2022, 2021, and 2020, were as follows: in fiscal year 2022, $6.41 for natural gas, $90.33 for oil and $38.09 for NGL; in fiscal year 2021, $2.79/Mcf for natural gas, $56.51/Bbl for oil and $20.58/Bbl for NGL; and in fiscal year 2020, $1.62/Mcf for natural gas, $40.18/Bbl for oil and $9.95/Bbl for NGL. These future net cash flows based on SEC pricing rules should not be construed as the fair market value of our reserves. A market value determination would need to include many additional factors, including anticipated natural gas, oil and NGL price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9/30/2022	9/30/2021	9/30/2020
Proved Developed	$ 374,063,580	$ 163,339,707	$ 57,306,480
Proved Undeveloped	83,098,064	16,244,436	8,779,289
Income Tax Expense	(107,209,614)	(40,697,140)	(13,224,535)
Total Proved	$ 349,952,030	$ 138,887,003	$ 52,861,234

10% Discounted Present Value of Estimated Future Net Cash Flows

	9/30/2022	9/30/2021	9/30/2020
Proved Developed	$ 184,948,239	$ 86,793,303	$ 33,270,804
Proved Undeveloped	52,978,389	9,731,036	5,659,479
Income Tax Expense	(55,357,247)	(21,733,997)	(7,796,130)
Total Proved	$ 182,569,381	$ 74,790,342	$ 31,134,153

Evaluation and Review of Reserves

The determination of reserve estimates is a function of testing and evaluating the production and development of natural gas and oil reservoirs in order to establish a production decline curve. The established production decline curves, in conjunction with natural gas and oil prices, development costs, production taxes and operating expenses, are used to estimate natural gas and oil 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.

We follow 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 16 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" for disclosures regarding our natural gas and oil 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 the reservoir 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, that 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 Cawley, Gillespie and Associates, Inc. ("CG&A") of Fort Worth, Texas, prepared our natural gas, oil and NGL reserves estimates as of September 30, 2022, and the independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, prepared our natural gas, oil and NGL reserves estimates as of September 30, 2021 and 2020. Within CG&A, the technical person primarily responsible for preparing the estimates set forth in the Report of CG&A dated October 4, 2022, filed as Exhibit 99.1 to this Annual Report on Form 10-K, was W. Todd Brooker. Mr. Brooker has been a Petroleum Consultant for CG&A since 1992 and became President in 2017. His responsibilities include reserve and economic evaluations, fair market valuations, field studies, pipeline resource studies and acquisition/divestiture analysis. His reserve reports are routinely used for public company SEC disclosures, and his experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures. Prior to CG&A, Mr. Brooker worked in Gulf of Mexico drilling and production engineering at Chevron USA. Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering. He is a registered professional engineer in Texas, No. 83462, a member of the Society of Petroleum Engineers (SPE) and a member of the Society of Petroleum Evaluation Engineers (SPEE). Mr. Brooker 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 Engineering. Our Vice President of Engineering 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, gas and oil 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. Our net proved natural gas, oil and NGL 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, 2022, 2021, and 2020. 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.

Natural Gas, Oil and NGL Production

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

	Year Ended 9/30/2022		
	Royalty Interest	Working Interest	Total
Mcf - Natural Gas	5,020,572	2,407,136	7,427,708
Bbls - Oil	119,518	79,017	198,535
Bbls - NGL	78,662	86,458	165,120
Mcfe	6,209,654	3,399,984	9,609,638

	Year Ended 9/30/2021 Royalty Interest	Working Interest	Total
Mcf - Natural Gas	3,026,761	3,672,959	6,699,720
Bbls - Oil	120,145	104,334	224,479
Bbls - NGL	71,655	99,833	171,488
Mcfe	4,177,559	4,897,960	9,075,519

	Year Ended 9/30/2020 Royalty Interest	Working Interest	Total
Mcf - Natural Gas	2,148,295	3,814,410	5,962,705
Bbls - Oil	135,572	134,213	269,785
Bbls - NGL	64,345	104,278	168,623
Mcfe	3,347,797	5,245,356	8,593,153

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 9/30/2022	Year Ended 9/30/2021	Year Ended 9/30/2020
Per Mcf, Natural Gas	$ 6.16	$ 3.13	$ 1.72
Per Bbl, Oil	$ 91.32	$ 56.58	$ 41.47
Per Bbl, NGL	$ 36.11	$ 23.80	$ 11.42
Per Mcfe	$ 7.27	$ 4.16	$ 2.72

Average Production (lifting) Costs	Year Ended 9/30/2022	Year Ended 9/30/2021	Year Ended 9/30/2020
(Per Total Mcfe)			
Well Operating Costs (1)	$ 1.03	$ 1.11	$ 1.12
Production Taxes (2)	0.34	0.21	0.12
	$ 1.37	$ 1.32	$ 1.24

(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 year 2022, approximately 64% of our natural gas, oil and NGL revenue was generated from royalty payments received on our mineral acreage. Royalty interests bear no share of the field operating costs on those producing wells but 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 our gross and net productive natural gas and oil wells as of September 30, 2022. We own either working interests, royalty interests or both in these wells. We do not operate any wells.

	Gross Working Interest Only Wells	Net Working Interest Only Wells	Gross Working Interest and Royalty Interest Wells	Net Working Interest and Royalty Interest Wells	Gross Royalty Only Wells	Net Royalty Only Wells	Total Gross Wells
Natural Gas	70	3.08	395	17.87	3,825	25.21	4,290
Oil	105	10.29	78	2.34	1,889	10.62	2,072
Total	175	13.37	473	20.21	5,714	35.83	6,362

Our average interest in royalty interest only wells is 0.63%. Our average interest in working interest wells is 5.57% working interest and 5.18% net revenue interest.

Information on multiple completions is not available from our 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, our ownership in each unitized field is counted as one gross well, as we do not have access to the actual well count in all of these unitized fields.

As of September 30, 2022, we owned 614,105 gross (66,421 net) developed mineral acres and leased 191,305 gross (16,260 net) developed acres.

Undeveloped Acreage

As of September 30, 2022, we owned 1,165,608 gross and 178,318 net undeveloped mineral acres. All of our leases are held by production ("HBP"), and we do not have any leases on undeveloped acres.

Drilling Activity

The following table sets forth our net productive development, exploratory and purchased wells and net dry development, exploratory and purchased wells in which we 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, 2022	-	0.986062	-
September 30, 2021	-	0.556684	-
September 30, 2020	-	0.597278	-
Exploratory Wells			
Fiscal years ended:			
September 30, 2022	-	-	-
September 30, 2021	-	-	-
September 30, 2020	-	-	-
Purchased Wells			
Fiscal years ended:			
September 30, 2022	-	1.108386	-
September 30, 2021	-	1.216467	-
September 30, 2020	-	0.364206	-

Present Activities

The following table sets forth our gross and net natural gas and oil wells being drilled or waiting on completion as of September 30, 2022, in which we own either a working interest, a royalty interest or both. These wells were not producing at September 30, 2022.

	Gross Working Interest Wells	Net Working Interest Wells	Gross Royalty Only Wells	Total Net Royalty Interest Wells
Natural Gas	-	-	168	0.81
Oil	-	-	4	0.01
Total	-	-	172	0.82

Other Facilities

We have an office lease on 8,776 square feet of office space in Oklahoma City, Oklahoma, which is scheduled to expire on August 31, 2027, and an office lease on 3,080 square feet of office space in Fort Worth, Texas, which is scheduled to expire on August 31, 2027.

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, 2022, or at the date of this Annual 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

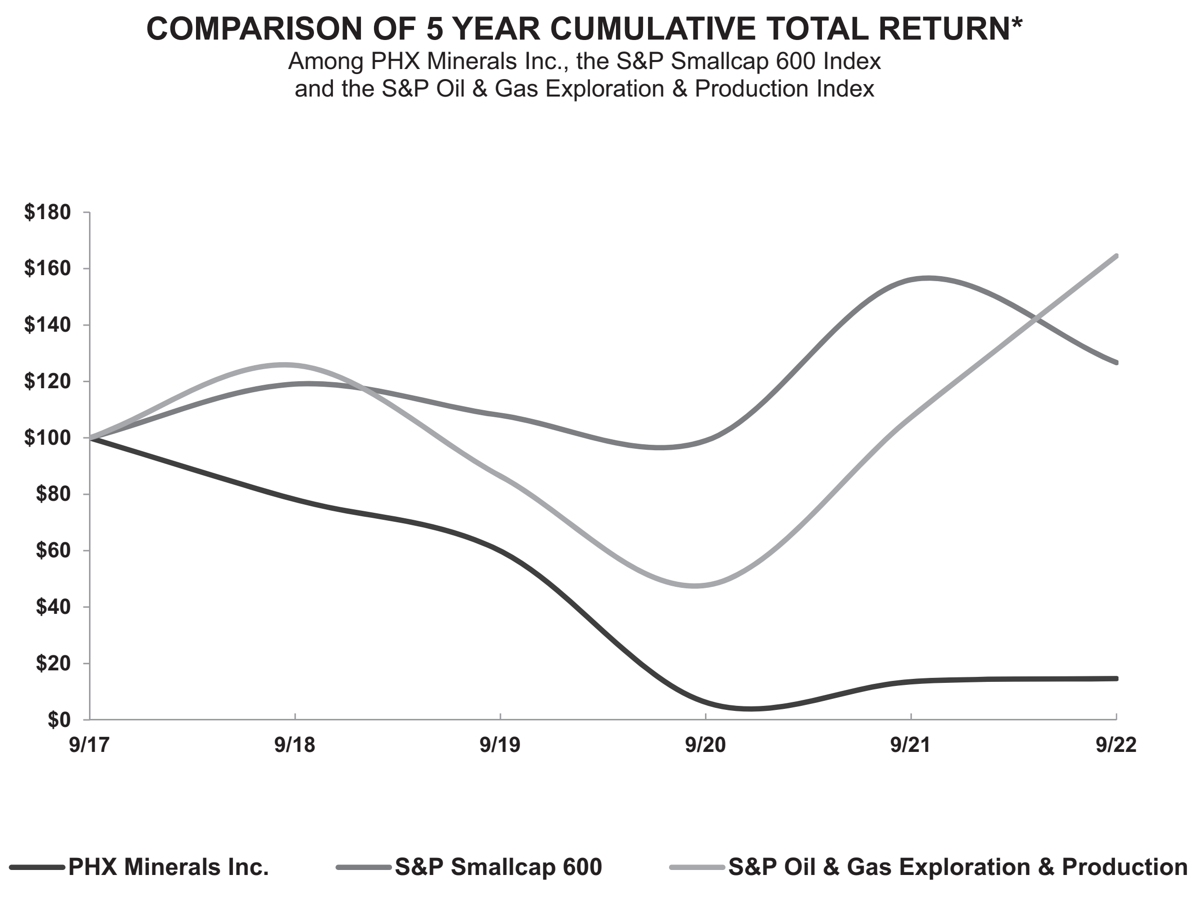
Market for our Common Stock

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

As of September 30, 2022, we were authorized to issue an aggregate of 54,000,500 shares of Common Stock.

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, 2017, and the relative performance of such investment is tracked through and including September 30, 2022. This table is not intended to forecast future performance of our Common Stock.



*$100 invested on 9/30/17 in stock or index, including reinvestment of dividends.
Fiscal year ending September 30.

Record Holders

At December 6, 2022, there were 1,280 holders of record of our Common Stock and approximately 7,000 beneficial owners.

Dividends

During the past three years, we have paid quarterly dividends ranging from $0.01 per share to $0.04 per share on our Common Stock. Approval by our Board is required before the declaration and payment of any dividends.

Historically, we have paid dividends to our stockholders on a quarterly basis. While we anticipate we will continue to pay dividends on our 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. Our Credit Agreement sets limits on dividend payments and stock repurchases if those payments would cause the Leverage Ratio (as defined in the Credit Agreement) to go above 2.50 to 1.0 or the Available Commitment (as defined in the Credit Agreement) to go below ten percent of the Borrowing Base (as defined in the Credit Agreement).

Purchases of Equity Securities by the Company

Following approval by our stockholders of our 2010 Restricted Stock Plan ("2010 Stock Plan") in March 2010, as amended in May 2018, our Board approved our repurchase program which, as amended, authorizes management to repurchase up to $1.5 million of our Common Stock at our discretion. The repurchase program has an evergreen provision which authorizes the repurchase of an additional $1.5 million of our Common Stock when the previous amount is utilized. As part of the amendment, the number of shares allowed to be purchased by us 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 our 2010 Stock Plan, as amended, (ii) contributed by us to the PHX Minerals 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 our Deferred Compensation Plan for Non-Employee Directors.

During the quarter ended September 30, 2022, we did not repurchase any shares of our Common Stock.

ITEM 6. Reserved

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. The following discussion and analysis generally discuss fiscal year 2022 and 2021 items and fiscal year-to-year comparisons between 2022 and 2021. Discussions of 2020 items and year-to-year comparisons between 2021 and 2020 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended September 30, 2021.

Business Overview

We are focused on perpetual natural gas and oil mineral ownership in resource plays in the United States. Prior to a strategy change in 2019, we participated with a working interest on some of our mineral and leasehold acreage and as a result, we still have legacy interests in leasehold acreage and non-operated interests in natural gas and oil properties. Effective October 8, 2020, our corporate name was changed to PHX Minerals Inc. to more accurately reflect our business strategy.

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

Strategic Focus on Mineral Ownership

During fiscal year 2019, we made the strategic decision to focus on perpetual natural gas and oil mineral ownership and growth through mineral acquisitions and the development of our significant mineral acreage inventory in our core focus areas. In accordance with this decision, we ceased taking working interest positions on our mineral and leasehold acreage going forward. During the three fiscal years ended September 30, 2022, we did not participate with a working interest in the drilling of any new wells. We believe that our strategy to focus on mineral ownership is the best path to giving our stockholders the greatest risk-weighted returns on their investments.

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 natural gas production for the fiscal year 2022 increased 11%, while oil and NGL production decreased 12% and 4%, respectively, from that of 2021. The 2022 fiscal year's higher natural gas, oil and NGL prices (as discussed below) and the overall production changes noted above resulted in an 85% increase in revenues from the sale of natural gas, oil and NGL in 2022.

Our proved natural gas, oil and NGL reserves decreased to 81.1 Bcfe in 2022, compared to 83.0 Bcfe in 2021, a decrease of approximately 1.9 Bcfe, or 2%. The decrease was primarily due to the sale of 17.6 Bcfe proved developed working interest properties in the Fayetteville Shale play in Arkansas, and the Arkoma Stack play and Western Anadarko Basin in Oklahoma, coupled with production and, to a lesser extent, performance revisions. This was partially offset by the acquisition of 15.6 Bcfe, predominately of royalty interest properties in the active drilling programs of the Haynesville Shale play in east Texas and western Louisiana and the Mississippi and Woodford Shale intervals in the SCOOP play in the Ardmore basin of Oklahoma. Additional reserve increases include (i) positive pricing revisions primarily related to natural gas and oil wells extending their economic limits later than was projected in 2021 due to higher commodity prices and other reserve parameters, such as differentials and lease operating costs, and (ii) additions resulting from our royalty interest ownership in the ongoing development of unconventional natural gas, utilizing horizontal drilling, in the Haynesville Shale play of East Texas and Western Louisiana; and the ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma.

As of September 30, 2022, we owned an average 0.5% net revenue interest, consisting of all royalty interest, in 172 wells that were being drilled or awaiting completion.

Results of Operations

The following table reflects certain operating data for fiscal 2022 and 2021:

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
Production:			
Natural Gas (Mcf)	7,427,708	6,699,720	11%
Oil (Bbls)	198,535	224,479	(12%)
NGL (Bbls)	165,120	171,488	(4%)
Mcfe	9,609,638	9,075,519	6%
Average Sales Price:			
Natural Gas (per Mcf)	$6.16	$3.13	97%
Oil (per Bbl)	$91.32	$56.58	61%
NGL (per Bbl)	$36.11	$23.80	52%
Mcfe	$7.27	$4.16	75%

Production by quarter for 2022 and 2021 was as follows (Mcfe):

	For the Year Ended September 30, 2022		
	Royalty Interest	Working Interest	Total
First quarter	1,225,220	903,028	2,128,248
Second quarter	1,547,609	912,433	2,460,042
Third quarter	1,595,323	834,437	2,429,760
Fourth quarter	1,841,502	750,086	2,591,588
Total	6,209,654	3,399,984	9,609,638

	For the Year Ended September 30, 2021		
	Royalty Interest	Working Interest	Total
First quarter	744,653	1,329,681	2,074,334
Second quarter	1,230,105	1,066,697	2,296,802
Third quarter	1,204,571	1,288,242	2,492,813
Fourth quarter	998,230	1,213,340	2,211,570
Total	4,177,559	4,897,960	9,075,519

Fiscal Year 2022 Compared to Fiscal Year 2021

Overview

Revenues increased in 2022 primarily due to higher natural gas, oil and NGL sales. We recorded net income of $20,409,272, or $0.59 per share, in 2022, compared to net loss of $6,217,237, or $0.24 per share, in 2021. Expenses increased in 2022, primarily the result of increases in G&A, production taxes, interest expense and transportation, gathering and marketing expenses, partially offset by an increase in gains on asset sales and decreases in DD&A, loss on debt extinguishment and LOE.

Natural Gas, Oil and NGL Sales

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
Natural gas, oil and NGL sales	$ 69,860,631	$ 37,749,044	85%

The increase was due to increased natural gas, oil and NGL prices of 97%, 61% and 52%, respectively, combined with higher natural gas volumes of 11%, partially offset by lower oil and NGL volumes of 12% and 4%, respectively.

The increase in natural gas production was primarily due to acquisitions and new drilling in the Haynesville Shale play of Texas and Louisiana, and slightly offset by divestiture of working interest assets in the Fayetteville Shale and naturally declining production in the Arkoma STACK. The decrease in oil production was a result of naturally declining production in high interest wells in the Eagle Ford and Bakken plays, wells shut in for workovers in the Eagle Ford, our strategy of no longer participating with working interest in new drilling in the Eagle Ford, and the natural decline of wells brought online in fiscal year 2021 in the STACK play. These decreases were partially offset by new drilling and acquisitions in the SCOOP. The decrease in NGL production is primarily attributable to the natural decline in high interest, liquids rich wells in the STACK. This was partially offset by new wells in the SCOOP.

Given our 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.

Gains (Losses) on Derivative Contracts

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
Cash received (paid) on settled derivative contracts:			
Cash received (paid) on settled derivative contracts, net(1)	$ (14,533,560)	$ (11,925,669)	(22%)
Non-cash gain (loss) on derivative contracts:			
Non-cash gain (loss) on derivative contracts, net	$ (2,299,518)	$ (4,276,820)	46%
Gains (losses) on derivative contracts, net	$ (16,833,078)	$ (16,202,489)	(4%)

	As of September 30,		
	2022	2021	
Fair value of derivative contracts			
Net asset (net liability)	$ (8,561,191)	$ (13,784,467)	38%

(1) Excludes $7,522,794 of cash paid to settle off-market derivative contracts that are not reflected on the Condensed Statements of Operations for the year ended September 30, 2022. See Note 12 to the financial statements in Item 8 – “Financial Statements and Supplementary Data” for further explanation on off-market derivative contracts.

The change in net (loss) gain on derivative contracts was due to the settlements of natural gas and oil collars and fixed price swaps and the change in valuation caused by the difference in September 30, 2022 pricing relative to the strike price on open derivative contracts.

Our natural gas and oil fixed price swaps in place at September 30, 2022, had expiration dates through December 2023. We utilize derivative contracts for the purpose of protecting our cash flow and return on investments.

Lease Operating Expenses (LOE)

	For the Year Ended September 30,				
		2022		2021	Percent Incr. or (Decr.)
Lease operating expenses	$	4,047,420	$	4,230,968	(4%)
Lease operating expenses per working interest MCFE	$	1.19	$	0.86	38%
Lease operating expenses per total MCFE	$	0.42	$	0.47	(11%)

We are responsible for a portion of LOE relating to a well as a working interest owner. LOE includes normal recurring and nonrecurring expenses associated with our working interests necessary to produce hydrocarbons from our natural gas and oil wells, including maintenance, repairs, salt water disposal, insurance and workover expenses. Total LOE related to field operating costs decreased $183,548, or 4%, in 2022 compared to 2021. The decrease in LOE was principally the result of the divestiture of working interest properties, partially offset by cost inflation associated with field operating activities.

Transportation, Gathering and Marketing

	For the Year Ended September 30,				
		2022		2021	Percent Incr. or (Decr.)
Transportation, gathering and marketing	$	5,890,390	$	5,767,287	2%
Transportation, gathering and marketing per MCFE	$	0.61	$	0.64	(5%)

Transportation, gathering and marketing increased $123,103, or 2%, in 2022 compared to 2021. This increase in costs was primarily due to increased production in 2022. The decrease in rate per Mcfe was primarily due to the divestiture of assets with higher associated transportation, gathering and marketing rates and the increase in natural gas sales in fields with lower associated transportation, gathering and marketing rates. Natural gas sales bear the large majority of our transportation, gathering and marketing fees.

Production Taxes

	For the Year Ended September 30,				
		2022		2021	Percent Incr. or (Decr.)
Production taxes	$	3,230,867	$	1,938,304	67%
Production taxes as % of sales		4.6%		5.1%	(10%)

Production taxes are paid on produced natural gas and oil based on a percentage of revenues from products sold at both fixed and variable rates established by federal, state or local taxing authorities. Production taxes increased $1,292,563, or 67%, in 2022 compared to 2021. The increase in amount was primarily the result of increased natural gas, oil and NGL sales of $32,111,587 during 2022.

Depreciation, Depletion and Amortization (DD&A)

	For the Year Ended September 30,				
		2022		2021	Percent Incr. or (Decr.)
Depreciation, depletion and amortization	$	7,278,118	$	7,745,804	(6%)
Depreciation, depletion and amortization per MCFE	$	0.76	$	0.85	(11%)

DD&A is the amount of cost basis of natural gas and oil properties attributable to the volume of hydrocarbons extracted during such period, calculated on a units-of-production basis for working interest, and on a straight-line basis for producing and non-producing minerals. Estimates of proved developed producing reserves are a major component of the calculation of depletion. DD&A decreased $467,686, or 6%, in 2022 compared to 2021, of which $921,685 of the decrease resulted from a $0.09 decrease in the DD&A rate per Mcfe, partially offset by an increase of $453,999 resulting from production increasing 6% in 2022. The rate decrease was due to working interest divestitures, partially offset by royalty interest acquisitions in 2022.

Provision for Impairment

Provision for impairment was $14,565 in 2022, as compared to $50,475 provision for impairment in 2021. During 2021, impairment of $37,879 was related to one field. These assets were written down to their fair market value as required by GAAP. The remaining $14,565 and $12,596 of impairment in the 2022 and 2021 periods, respectively, were related to working interest wells in which we assigned our interests to the operator.

Interest Expense

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
Interest Expense	$ 1,164,992	$ 995,127	17%
Weighted average debt outstanding	$ 25,004,110	$ 23,725,079	5%

The increase was due to a higher outstanding debt balance and an increase in the average interest rate in 2022 compared to 2021.

General and Administrative Costs (G&A)

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
General and administrative costs	$ 11,500,594	$ 8,207,882	40%

G&A are costs not directly associated with the production of natural gas and oil and include the cost of employee salaries and related benefits, office expenses and fees for professional services. G&A for 2022 increased $3,292,712 as compared to 2021. The increase was primarily due to legal expenses associated with reincorporating in the state of Delaware, increased transaction activity and restricted stock expense during the year.

Loss on Debt Extinguishment

When we terminated our credit facility led by Bank of Oklahoma in the fourth quarter of 2021, we wrote-off all associated costs that had been previously capitalized.

Losses (Gains) on Asset Sales and Other

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
Losses (gains) on asset sales and other	$ (4,243,163)	$ (356,127)	(1,091%)

The increase in gain on asset sales and other is primarily related to divestitures during 2022.

Provision (Benefit) for Income Taxes

	For the Year Ended September 30,		
	2022	2021	Percent Incr. or (Decr.)
Provision (benefit) for income taxes	$ 4,202,000	$ (651,051)	745%
Effective tax rate	17%	(9%)	289%

Provision (benefit) for income taxes changed $4,853,051, from a $651,051 benefit in 2021 to a $4,202,000 provision in 2022. The change in provision (benefit) for income taxes resulted primarily from the change in our net income (loss) from a net loss of $6,217,237 in 2021 to net income of $20,409,272 in 2022.

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 2021 Compared to Fiscal Year 2020

Overview

Revenues decreased in 2021 primarily due to an increase in losses on derivative contracts, partially offset by higher natural gas, oil and NGL sales. We recorded a net loss of $6,217,237, or $0.24 per share, in 2021, compared to net loss of $23,952,037, or $1.41 per share, in 2020. Expenses decreased in 2021, primarily the result of decreases in provision for impairment (non-cash), DD&A, LOE and interest expense, partially offset by an increase in transportation, gathering and marketing expenses, production taxes and loss on debt extinguishment.

Natural Gas, Oil and NGL Sales

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Natural gas, oil and NGL sales	$ 37,749,044	$ 23,370,003	62%

The increase was due to increased natural gas, oil and NGL prices of 82%, 36% and 108%, respectively, combined with higher natural gas and NGL volumes of 12% and 2%, respectively, partially offset by lower oil volumes of 17%.

The increase in natural gas production was primarily due to acquisitions in the Haynesville Shale play of Texas and Louisiana, and slightly offset by naturally declining production in the SCOOP and Arkoma STACK. The decrease in oil production was a result of naturally declining production in high interest wells in the Eagle Ford and Bakken plays, our strategy of no longer participating with working interest in new drilling in the Eagle Ford, and reduced drilling activity in the Bakken. These decreases were slightly offset by acquisitions and new drilling in the STACK. The increase in NGL production is primarily attributable to high interest wells coming back online after being shut-in for part of fiscal year 2020, as well as new wells being brought online in the STACK. This was slightly offset by naturally declining production in the SCOOP.

Given our 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

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Cash received (paid) on settled derivative contracts:			
Cash received (paid) on settled derivative contracts, net	$ (11,925,669)	$ 4,109,210	(390%)
Non-cash gain (loss) on derivative contracts:			
Non-cash gain (loss) on derivative contracts, net	$ (4,276,820)	$ (3,201,791)	(34%)
Gains (losses) on derivative contracts, net	$ (16,202,489)	$ 907,419	(1,886%)

	As of September 30,		
	2021	2020	
Fair value of derivative contracts			
Net asset (net liability)	$ (13,784,467)	$ (707,647)	(1,848%)

The change in net loss on derivative contracts was due to the natural gas and oil collars and fixed price swaps being less beneficial in 2021 in relation to their respective contracted volumes and prices. The change from a net liability position of $707,647 at September 30, 2020, to a net liability position of $13,784,467 at September 30, 2021, resulted from non-cash loss on derivative contracts in the 2021 period of $4,276,820 and entry into off-market hedges with BP Energy Company (“BP”) for $8.8 million in cash. See Note 12 to the financial statements in Item 8 – “Financial Statements and Supplementary Data” for further explanation.

Our natural gas and oil fixed price swaps in place at September 30, 2021, had expiration dates through March 2023. We utilize derivative contracts for the purpose of protecting our cash flow and return on investments.

Lease Operating Expenses (LOE)

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Lease operating expenses	$ 4,230,968	$ 4,841,541	(13%)
Lease operating expenses per MCFE	$ 0.47	$ 0.56	(16%)

We are responsible for a portion of LOE relating to a well as a working interest owner. LOE includes normal recurring and nonrecurring expenses associated with our working interests necessary to produce hydrocarbons from our natural gas and oil wells, including maintenance, repairs, salt water disposal, insurance and workover expenses. Total LOE related to field operating costs decreased $610,573, or 13%, in 2021 compared to 2020. The decrease in LOE rate was principally the result of our strategic decision to cease participating with a working interest in new wells and the increase in royalty interest production as a percentage of total production.

Transportation, Gathering and Marketing

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Transportation, gathering and marketing	$ 5,767,287	$ 4,812,869	20%
Transportation, gathering and marketing per MCFE	$ 0.64	$ 0.56	14%

Transportation, gathering and marketing increased $954,418, or 20%, in 2021 compared to 2020. This increase in costs was primarily due to increased production in 2021. The increase in rate per Mcfe was primarily due to the increase in natural gas sales in relation to other products. Natural gas sales bear the large majority of our transportation, gathering and marketing fees.

Production Taxes

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Production taxes	$ 1,938,304	$ 1,022,912	89%
Production taxes as % of sales	5.1%	4.4%	16%

Production taxes are paid on produced natural gas and oil based on a percentage of revenues from products sold at both fixed and variable rates established by federal, state or local taxing authorities. Production taxes increased $915,392, or 89%, in 2021 compared to 2020. The increase in amount was primarily the result of increased natural gas, oil and NGL sales of $14,379,041 during 2021.

Depreciation, Depletion and Amortization (DD&A)

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Depreciation, depletion and amortization	$ 7,745,804	$ 11,313,783	(32%)
Depreciation, depletion and amortization per MCFE	$ 0.85	$ 1.32	(36%)

DD&A is the amount of cost basis of natural gas and oil properties attributable to the volume of hydrocarbons extracted during such period, calculated on a units-of-production basis for working interest, and on a straight-line basis for producing and non-producing minerals. Estimates of proved developed producing reserves are a major component of the calculation of depletion. DD&A decreased $3,567,979, or 32%, in 2021 compared to 2020, of which $4,204,702 of the decrease resulted from a $0.47 decrease in the DD&A rate per Mcfe, partially offset by an increase of $636,723 resulting from production increasing 6% in 2021. The rate decrease was partially due to higher natural gas, oil and NGL prices utilized in the reserve calculations during the 2021 period, as compared to 2020 period, lengthening the economic life of wells. This resulted in higher projected remaining reserves on a significant number of wells causing decreased units of production DD&A, despite the increase in projection.

Provision for Impairment

Provision for impairment was $50,475 in 2021, as compared to $29,904,528 provision for impairment in 2020. During 2021, impairment of $37,879 was related to one field. These assets were written down to their fair market value as required by GAAP. During 2020, impairment of $29,315,806 was recorded on seven different fields including the Fayetteville and Eagle Ford shales, which represented 89% of our total impairment. The impairment in these seven fields was caused by lower future prices reducing future net cash flows associated with these fields, which caused these assets to fail the step one test for impairment as their 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 remaining $12,596 and $588,721 of impairment in the 2021 and 2020 periods, respectively, were recorded on other assets.

Interest Expense

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Interest Expense	$ 995,127	$ 1,286,788	(23%)
Weighted average debt outstanding	$ 23,725,079	$ 32,290,257	(27%)

The decrease was due to a lower outstanding debt balance in 2021 compared to 2020.

General and Administrative Costs (G&A)

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
General and administrative costs	$ 8,207,882	$ 8,024,901	2%

G&A are costs not directly associated with the production of natural gas and oil and include the cost of employee salaries and related benefits, office expenses and fees for professional services. G&A for 2021 increased $182,981 as compared to 2020. The slight increase was primarily due to increased activity during the year, partially offset by our cost reduction efforts.

Loss on Debt Extinguishment

When we terminated our credit facility led by Bank of Oklahoma, we wrote-off all associated costs that had been previously capitalized.

Loss (Gain) on Asset Sales and Other

In 2021, we recorded a net gain on asset sales of $312,838 as compared to a net gain of $3,973,256 in 2020. During 2021, we sold 2,857 net mineral acres in Central Basin Platform in Texas for $285,714, resulting in a gain of $236,907. The remaining gain on asset sales in 2021 was due to various immaterial asset sales less adjustments.

During the first quarter of 2020, we sold producing mineral acreage in Eddy County, New Mexico, for a gain of $3,272,499. We utilized a like-kind exchange under Internal Revenue Code Section 1031 to defer income tax on all of the gain by offsetting it with the STACK/SCOOP mineral acreage acquisition that was purchased during the quarter using qualified exchange accommodation agreements. During the fourth quarter of 2020, we sold 5,925 non-producing mineral acres in northwestern Oklahoma for a gain of $717,640. The remaining gain on asset sales in 2020 was due to various asset sales less adjustments.

Provision (Benefit) for Income Taxes

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Provision (benefit) for income taxes	$ (651,051)	$ (8,289,000)	(92%)
Effective tax rate	9%	26%	(65%)

Provision (benefit) for income taxes changed $7,637,949, from a $8,289,000 benefit in 2020 to a $651,051 benefit in 2021. The income tax benefit change resulted primarily from the reduction in net loss.

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

We had positive working capital (current assets less current liabilities excluding current derivatives) of $14,533,225 at September 30, 2022, compared to positive working capital of $9,175,126 at September 30, 2021.

Liquidity

Cash and cash equivalents were $3,396,809 as of September 30, 2022, compared to $2,438,511 at September 30, 2021, an increase of $958,298. Cash flows for the year ended September 30, 2022 and 2021, are summarized as follows:

	For the Year Ended September 30,		
Net cash provided (used) by:	2022	2021	Change
Operating activities	$ 37,531,650	$ 3,942,087	$ 33,589,563
Investing activities	(30,860,030)	(20,368,919)	(10,491,111)
Financing activities	(5,713,322)	8,174,948	(13,888,270)
Increase (decrease) in cash and cash equivalents	$ 958,298	$ (8,251,884)	$ 9,210,182

<u>Operating activities</u>:

Net cash provided by operating activities increased $33,589,563 during 2022, as compared to 2021, primarily as a result of the following:

- Receipts of natural gas, oil and NGL sales (net of production taxes and gathering, transportation and marketing costs) and other increased $27,620,895;
- Decreased net payments on derivative contracts of $9,129,420;
- Increased lease bonus receipts of $246,554; and
- Decreased payments for interest expense of $24,057.

Offset by:

- Increased income tax payments of $1,775,474;
- Increased payments for G&A and other expense of $1,650,019; and
- Increased field operating expenses of $5,870.

<u>Investing activities</u>:

Net cash used in investing activities increased $10,491,111 during 2022, as compared to 2021, primarily as a result of the following:

- Higher acquisition activity increased our expenditures by $22,900,889.

Offset by:

- Higher proceeds received from the sale of assets of $12,229,244; and

- Lower workover activity during 2022 decreased our capital expenditures by $180,534.

Financing activities:

Net cash used in financing activities increased $13,888,270 during 2022, as compared to 2021, primarily as a result of the following:

- Increased net cash payments on off-market derivative contracts of $28,060,104 during 2022;
- Increased dividend payments by $1,197,453 during 2022; and
- Decreased net proceeds from equity issuance of $6,681,599 during 2022.

Offset by:

- Increased net borrowings on debt of $22,050,000.

Capital Resources

We had no capital expenditures to drill and complete wells in 2022, as a result of our strategy to cease participating in new wells with a working interest at the end of fiscal year 2019. We currently have no remaining commitments that would require significant capital to drill and complete wells.

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

Over the past five quarters, we made the following property acquisitions:

Quarter Ended (4)	Net royalty acres (1)(2)	Cash	Number of shares issued (3)	Total Purchase Price (1)	Area of Interest
September 30, 2022					
	63	$0.7million	-	$0.7million	Haynesville / LA
	17	$0.2million	-	$0.2million	SCOOP / OK
	85	$1.5million	-	$1.5million	Haynesville / LA
	214	$3.0million	-	$3.0million	Haynesville / LA
	110	$1.0million	-	$1.0million	Haynesville / LA
	295	$5.5million	-	$5.5million	Haynesville / LA
	140	$1.7million	-	$1.7million	SCOOP / OK
June 30, 2022					
	60	$0.6million	-	$0.6million	SCOOP / OK
	46	$0.8million	-	$0.8million	Haynesville / LA
	56	$0.4million	-	$0.4million	Haynesville / LA
	88	$0.9million	-	$0.9million	SCOOP / OK
	503	$5.0million	-	$5.0million	Haynesville / LA, TX
	92	$0.6million	-	$0.6million	Haynesville / LA
	25	$0.3million	-	$0.3million	Haynesville / LA
	68	$0.5million	-	$0.5million	SCOOP / OK
March 31, 2022					
	58	$0.5million	-	$0.5million	SCOOP / OK
	500	$6.4million	-	$6.4million	Haynesville / LA
	68	$0.7million	-	$0.7million	Haynesville / TX
	166	$1.3million	-	$1.3million	SCOOP / OK
	33	$0.4million	-	$0.4million	Haynesville / TX
December 31, 2021					
	426	$5.8million	-	$5.8million	Haynesville / LA
	847	$0.6million	1,519,481	$4.1million	Haynesville / LA
	172	$1.4million	-	$1.4million	SCOOP / OK
	103	$0.6million	-	$0.6million	Haynesville / TX
	116	$1.7million	-	$1.7million	Haynesville / LA
	220	$1.2million	-	$1.2million	SCOOP / OK
September 30, 2021					
	817	$0.7million	2,349,407	$7.3million	Haynesville / LA, TX

(1) Excludes subsequent closing adjustments and insignificant acquisitions.
(2) An estimated net royalty equivalent was used for the minerals included in the net royalty acres.
(3) The Company's policy is to classify all costs associated with equity issuances as financial costs in the Statements of Cash Flows.
(4) Presented in chronological order with most recent at top.

We received lease bonus payments during fiscal year 2022 totaling approximately $0.7 million. Looking forward, the cash flow from bonus payments associated with the leasing of drilling rights on our mineral acreage is difficult to project and management plans to continue to actively pursue leasing opportunities.

With continued natural gas and oil price volatility, management continues to evaluate opportunities for product price protection through additional hedging of our future natural gas and oil production. See Note 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for a complete list of our outstanding derivative contracts.

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

	Twelve months ended 9/30/2022
Cash provided by operating activities	$ 37,531,650
Cash provided (used) by:	
Capital expenditures - acquisitions	(43,525,236)
Capital expenditures - legacy working interest wells and furniture and fixtures	(552,638)
Quarterly dividends	(2,257,901)
Treasury stock purchases	(1,855)
Net borrowings (payments) on credit facility	10,800,000
Net proceeds from sales of assets	13,217,844
Cash receipts from (payments on) off-market derivative contracts	(19,260,104)
Net proceeds from equity issuance	5,006,538
Net cash used	(36,573,352)
Net increase (decrease) in cash	$ 958,298

Outstanding borrowings under our Credit Facility at September 30, 2022 were $28,300,000.

Looking forward, we expect to fund overhead costs, mineral and royalty acquisitions, and dividend payments from cash provided by operating activities, cash on hand and borrowings from our Credit Facility. We had availability of $21,700,000 at September 30, 2022 under our Credit Facility and were in compliance with our debt covenants (current ratio, debt to trailing 12-month EBITDAX, as defined in the Credit Agreement, and restricted payments limited by leverage ratio). The debt covenants in the Credit Agreement limit the maximum ratio of our debt to EBITDAX to no more than 3.5:1.

We have our Credit Facility with certain lenders and Independent Bank, as Administrative Agent and Letter of Credit Issuer, which provides for up to $100 million in borrowings from time to time and is subject to an at least semi-annual borrowing base determination. The borrowing base at September 30, 2022, was $50,000,000 and all obligations under the Credit Agreement are secured, subject to permitted liens and other exceptions, by a first-priority security interest on substantially all of our personal property and at least 80% of the total value of our proved, developed and producing Oil and Gas Properties. The revolving loan matures on September 1, 2025. Borrowings under the revolving loan are due at maturity. Interest on the Credit Agreement is calculated based on either (a) the Secured Overnight Financing Rate ("SOFR") plus an applicable margin ranging from 2.750% to 3.750% per annum based on our Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on our Borrowing Base Utilization. Under the terms of the Credit Agreement, a 5% interest penalty may apply to any outstanding amount not paid when due or that remains outstanding while an event of default exists. At September 30, 2022, the effective rate was 5.93%. The Credit Agreement contains financial and various other covenants that are common in such agreements, including a (a) maximum ratio of consolidated Funded Indebtedness to consolidated pro forma EBITDAX of 3.50 to 1.00, calculated on a rolling four-quarter basis, and (b) minimum ratio of consolidated Current Assets to consolidated Current Liabilities (excluding the Loan Balance) of 1.00 to 1.00. Other negative covenants include restrictions on our ability to incur debt, grant liens, make fundamental changes and engage in certain transactions with affiliates. The Credit Agreement also restricts our ability to make certain restricted payments if both before and after the Restricted Payment (i) the Available Commitment is less than or equal to ten percent (10%) of the Borrowing Base or (ii) the Leverage Ratio on a pro forma basis is greater than 2.50 to 1.00. All capitalized terms in this description of the Credit Facility that are not otherwise defined in this Annual Report have the meaning assigned to them in the Credit Agreement.

Based on our expected capital expenditure levels, anticipated cash provided by operating activities for 2023, combined with availability under our Credit Facility and potential future sales of Common Stock under our currently effective shelf registration statement, we believe we have sufficient liquidity to fund our ongoing operations.

On August 25, 2021, we entered into an At-The-Market Equity Offering Sales Agreement (the "ATM Agreement") with Stifel, Nicolaus & Company, Incorporated, as sales agent and/or principal ("Stifel"), pursuant to which we may offer and sell, from time to time through or to Stifel, up to 3,000,000 shares of our Common Stock. As of September 30, 2022, we have sold 1,531,013 shares of Common Stock pursuant to the ATM Agreement for proceeds of approximately $5.9 million, net of commissions paid. As disclosed in Item 9B – Other Information of this Annual Report on Form 10-K, we voluntarily terminated the ATM Agreement on December 12, 2022.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have our Credit Facility with certain lenders and Independent Bank, as Administrative Agent and Letter of Credit Issuer, which provides for up to $100 million in borrowings from time to time and is subject to an at least semi-annual borrowing base determination. The borrowing base at September 30, 2022, was $50,000,000 and all obligations under the Credit Agreement are secured, subject to permitted liens and other exceptions, by a first-priority security interest on substantially all of our personal property and at least 80% of the total value of our proved, developed and producing Oil and Gas Properties. The revolving loan matures on September 1, 2025. Borrowings under the revolving loan are due at maturity. Interest on the Credit Agreement is calculated based on either (a) the Secured Overnight Financing Rate ("SOFR") plus an applicable margin ranging from 2.750% to 3.750% per annum based on our Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on our Borrowing Base Utilization. Under the terms of the Credit Agreement, a 5% interest penalty may apply to any outstanding amount not paid when due or that remains outstanding while an event of default exists. At September 30, 2022, the effective rate was 5.93%. All capitalized terms in this description of the Credit Facility that are not otherwise defined in this Annual Report have the meaning assigned to them in the Credit Agreement.

Determinations of the borrowing base are made at least semi-annually (on December 1 and June 1) or whenever the banks, in their discretion, believe that there has been a material change in the value of the natural gas and oil properties. The Credit Agreement contains financial and various other covenants that are common in such agreements, including a (a) maximum ratio of consolidated Funded Indebtedness to consolidated pro forma EBITDAX of 3.50 to 1.00, calculated on a rolling four-quarter basis, and (b) minimum ratio of consolidated Current Assets to consolidated Current Liabilities (excluding the Loan Balance) of 1.00 to 1.00. Other negative covenants include restrictions on our ability to incur debt, grant liens, make fundamental changes, and engage in certain transactions with affiliates. The Credit Agreement also restricts our ability to make certain restricted payments if before or after the Restricted Payment (i) the Available Commitment is less than or equal to ten percent (10%) of the Borrowing Base or (ii) the Leverage Ratio on a pro forma basis is greater than 2.50 to 1.00. At September 30, 2022, we were in compliance with the covenants of the Credit Facility, had $28,300,000 outstanding and had $21,700,000 of borrowing base availability under the Credit Facility.

The table below summarizes our contractual obligations and commitments as of September 30, 2022:

	Payments due by period				
Contractual Obligations and Commitments	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$28,300,000	$ -	$ 28,300,000	$ -	$ -
Building lease	$ 1,323,444	$ 256,795	$ 533,748	$ 532,901	$ -

Our building leases are accounted for as operating leases, and a related operating lease right-of-use ("ROU") asset and operating lease liability has been recognized on our balance sheets.

At September 30, 2022, our derivative contracts were in a net liability position of $8,561,191. 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 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding our derivative contracts.

As of September 30, 2022, our estimate for asset retirement obligations was $1,901,904. Asset retirement obligations represent our share of the future expenditures to plug and abandon the wells in which we own 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 11 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding our asset retirement obligations.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements during 2022 and 2021, and we currently do not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on our financial condition, or result in 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 our 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: natural gas, crude oil and NGL reserve estimation; derivative contracts; impairment of assets; natural gas, oil and NGL 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 natural gas, oil and NGL sales revenue accrual is particularly subject to estimate inaccuracies due to our status as a non-operator on all of our 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 natural gas, oil and NGL revenue accrual to be subject to future change.

Natural Gas, Oil and NGL Reserves

Management considers the estimation of our natural gas, crude oil and NGL reserves to be the most significant of our judgments and estimates. These estimates affect the unaudited standardized measure disclosures included in Note 16 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" as well as DD&A and impairment calculations for working interest properties. Changes in natural gas, crude oil and NGL reserve estimates affect our calculation of DD&A, asset retirement obligations and assessment of the need for asset impairments. Our Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares our estimates of natural gas, crude oil and NGL 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, we update the reserve calculations utilizing prices which are updated through the current period. In accordance with SEC rules, our 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 our 2022 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $727,812 annual change in DD&A expense. Natural gas, crude oil and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future natural gas, crude oil and NGL pricing assumptions are used by management to prepare estimates of natural gas, crude oil and NGL reserves and future net cash flows used in asset impairment assessments and in formulating management's overall operating decisions.

Successful Efforts Method of Accounting

We have elected to utilize the successful efforts method of accounting for our natural gas and oil 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 for working interest wells (the ratio of natural gas, oil and NGL volumes produced to total proved or proved developed reserves is used to amortize the remaining asset basis on each producing property) as natural gas, oil and NGL is produced. Our 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 our total expenditures for natural gas and oil properties. This accounting method may yield significantly different operating results than the full cost method.

Derivative Contracts

We have entered into costless collar contracts and fixed swap contracts. These instruments are intended to reduce our exposure to short-term fluctuations in the price of natural gas and oil. 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 our natural gas and oil production, provide only partial price protection against declines in natural gas and oil prices and may limit the benefit of future increases in prices. Our derivative contracts are with BP and are secured under our Credit Facility.

We are 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, 2022, we 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 natural gas and oil properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than our 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 natural gas, oil and NGL; future production costs; estimates of future natural gas, oil and NGL reserves to be recovered and the timing thereof; economic and regulatory climates and other factors. We estimate future net cash flows on our natural gas and oil properties utilizing differentially adjusted forward pricing curves for natural gas, oil and NGL 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 natural gas, oil and NGL reserves. A further reduction in natural gas, oil and NGL prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to 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 we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Natural Gas, Oil and NGL Sales Revenue Accrual

We do not operate our natural gas and oil properties and, therefore, receive actual natural gas, oil and NGL 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, as well as public and private sources, and natural gas, oil and NGL 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, we utilize past production receipts and estimated sales price information to estimate our accrual of revenue on all other wells each quarter. The natural gas, oil and NGL 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 natural gas, oil and NGL. These variables could lead to an over or under accrual of natural gas, oil and NGL sales at the end of any particular quarter. Based on past history, our 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 our 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 which takes into account historical data and current pricing. We have certain state and may have federal 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.

The above description of our 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

Commodity Price Risk

Natural gas, oil and NGL prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of natural gas, oil and NGL price trends, and there remains a wide divergence in the opinions held in the industry. We can be significantly impacted by changes in natural gas and oil prices. The market price of natural gas, oil and NGL in 2023 will impact the amount of cash generated from operating activities, which will in turn impact the level of our capital expenditures for acquisitions and production. Excluding the impact of our 2023 derivative contracts (see below), the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $742,771 for operating revenue based on our prior year natural gas volumes. The price sensitivity in 2023 for each $1.00 per barrel change in wellhead oil is approximately $198,535 for operating revenue based on our prior year oil volumes.

Financial Market Risk

Operating income could also be impacted, to a lesser extent, by changes in the market interest rates related to our Credit Facility. Interest under our Credit Facility is calculated based on either (a) SOFR plus an applicable margin ranging from 2.750% to 3.750% per annum based on our Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on our Borrowing Base Utilization. Under the terms of the Credit Agreement, a 5% interest penalty may apply to any outstanding amount not paid when due or that remains outstanding while an event of default exists. At September 30, 2022, we had $28,300,000 outstanding under this facility and the effective interest rate was 5.93%. 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 $283,000 for the year ended September 30, 2022, assuming that our indebtedness remained constant throughout the period. At this point, we do not believe that our liquidity has been materially affected by the debt market uncertainties noted in the last few years, and we do not believe that our liquidity will be significantly impacted in the near future. All capitalized terms in this description of the interest rate under the Credit Facility that are not otherwise defined in this Annual Report have the meaning assigned to them in the Credit Agreement.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of PHX Minerals Inc.

Opinion on Internal Control Over Financial Reporting

We have audited PHX Minerals Inc.'s internal control over financial reporting as of September 30, 2022, 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, PHX Minerals Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of September 30, 2022, 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 balance sheets of the Company as of September 30, 2022, and 2021, the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2022, and the related notes, and our report dated December 13, 2022, 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 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 13, 2022

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of PHX Minerals Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of PHX Minerals Inc. (the Company) as of September 30, 2022 and 2021, the related statements of operations, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2022, 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, 2022, 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 13, 2022, 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 the Company's 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 audits 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

	Depreciation, Depletion and Amortization of Producing Natural Gas and Oil Working Interest Properties
Description of the Matter	At September 30, 2022, the net book value of the Company's natural gas and oil properties was $132.4 million, and depreciation, depletion and amortization ("DD&A") expense related to the Company's natural gas and oil properties was $7.2 million. Of this amount, $3.3 million relates to DD&A on working interest properties. As discussed in Note 1, the Company follows the successful efforts method of accounting for its natural gas and oil producing activities. DD&A on working interest properties is recorded based on the units-of-production method on an individual property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent Consulting Petroleum Engineers. Proved natural gas, oil and NGL reserves are estimated quantities of natural gas, oil and NGL which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. The Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of natural gas, oil and NGL reserves. 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, the reserve estimates are 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. Natural gas, oil and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

Significant judgment is required by the Independent Consulting Petroleum Engineers in evaluating geological and engineering data used to estimate natural gas, oil and NGL reserves. Estimating reserves also requires the selection of inputs, including natural gas, oil and NGL price assumptions, operating and capital costs assumptions and tax rates by jurisdiction, among others. Auditing the Company's working interest properties DD&A calculations is especially complex because of the use of the work of the Independent Petroleum Consulting Engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved developed natural gas, oil and NGL reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of internal controls over the Company's process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved developed natural gas, oil and NGL reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Independent Petroleum Consulting Engineers used to prepare the natural gas, oil and NGL reserve estimates. In addition, in assessing whether we can use the work of the Independent Petroleum Consulting Engineers we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved natural gas, oil and NGL reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved developed natural gas, oil and NGL reserve amounts used in the calculations to the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1989.
Oklahoma City, Oklahoma
December 13, 2022

PHX Minerals Inc.
Balance Sheets

	September 30, 2022	September 30, 2021
Assets		
Current Assets:		
Cash and cash equivalents	$ 3,396,809	$ 2,438,511
Natural gas, oil and NGL sales receivables (net of $0 allowance for uncollectable accounts)	13,152,274	6,428,982
Refundable income taxes	-	2,413,942
Other	1,372,847	942,082
Total current assets	17,921,930	12,223,517
Properties and equipment at cost, based on successful efforts accounting:		
Producing natural gas and oil properties	248,978,928	319,984,874
Non-producing natural gas and oil properties	51,779,336	40,466,098
Other	1,085,056	794,179
	301,843,320	361,245,151
Less accumulated depreciation, depletion and amortization	(168,759,385)	(257,643,661)
Net properties and equipment	133,083,935	103,601,490
Operating lease right-of-use assets	739,131	607,414
Other, net	757,116	578,593
Total assets	$ 152,502,112	$ 117,011,014
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 647,217	$ 772,717
Derivative contracts, net	7,873,979	12,087,988
Current portion of operating lease liability	213,355	132,287
Income taxes payable	495,858	334,050
Accrued liabilities and other	2,032,275	1,809,337
Total current liabilities	11,262,684	15,136,379
Long-term debt	28,300,000	17,500,000
Deferred income taxes	1,585,906	343,906
Asset retirement obligations	1,901,904	2,836,172
Derivative contracts, net	687,212	1,696,479
Operating lease liability, net of current portion	985,887	789,339
Total liabilities	44,723,593	38,302,275
Stockholders' equity:		
Voting common stock, par value $0.01666 per share: 54,000,500 shares authorized and 35,776,752 shares issued and outstanding at September 30, 2022; 36,000,500 shares authorized and 32,770,433 shares issued and outstanding at September 30, 2021	596,041	545,956
Capital in excess of par value	44,177,051	33,213,645
Deferred directors' compensation	1,496,243	1,768,151
Retained earnings	67,117,791	48,966,420
	113,387,126	84,494,172
Treasury stock, at cost: 377,232 shares at September 30, 2022; 388,545 shares at September 30, 2021	(5,608,607)	(5,785,433)
Total stockholders' equity	107,778,519	78,708,739
Total liabilities and stockholders' equity	$ 152,502,112	$ 117,011,014

See accompanying notes.

PHX Minerals Inc.
Statements of Operations

	Year ended September 30, 2022	2021	2020
Revenues:			
Natural gas, oil and NGL sales	$ 69,860,631	$ 37,749,044	$ 23,370,003
Lease bonuses and rental income	467,502	425,113	690,961
Gains (losses) on derivative contracts (Note 12)	(16,833,078)	(16,202,489)	907,419
	53,495,055	21,971,668	24,968,383
Costs and expenses:			
Lease operating expenses	4,047,420	4,230,968	4,841,541
Transportation, gathering and marketing	5,890,390	5,767,287	4,812,869
Production taxes	3,230,867	1,938,304	1,022,912
Depreciation, depletion and amortization	7,278,118	7,745,804	11,313,783
Provision for impairment	14,565	50,475	29,904,528
Interest expense	1,164,992	995,127	1,286,788
General and administrative	11,500,594	8,207,882	8,024,901
Loss on debt extinguishment	-	260,236	-
Losses (gains) on asset sales and other	(4,243,163)	(356,127)	(3,997,902)
	28,883,783	28,839,956	57,209,420
Income (loss) before provision (benefit) for income taxes	24,611,272	(6,868,288)	(32,241,037)
Provision (benefit) for income taxes	4,202,000	(651,051)	(8,289,000)
Net income (loss)	$ 20,409,272	$ (6,217,237)	$ (23,952,037)
Basic and diluted earnings (loss) per common share (Note 7)	$ 0.59	$ (0.24)	$ (1.41)

See accompanying notes.

PHX Minerals Inc.
Statements of Stockholders' Equity

	Voting Common Stock Shares	Voting Common Stock Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
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
Net income (loss)	-	-	-	-	(23,952,037)	-	-	(23,952,037)
Purchase of treasury stock	-	-	-	-	-	(632)	(7,635)	(7,635)
Issuance of treasury shares to ESOP	-	-	(974,806)	-	-	72,101	1,077,910	103,104
Restricted stock awards	-	-	743,897	-	-	-	-	743,897
Dividends declared ($0.10 per share)	-	-	-	-	(1,652,164)	-	-	(1,652,164)
Distribution of restricted stock to officers and directors	-	-	(82,820)	-	-	5,546	82,914	94
Distribution of deferred directors' compensation	-	-	(129,575)	(910,182)	-	69,549	1,039,757	-
Common shares to be issued to directors for services	-	-	-	228,408	-	-	-	228,408
Equity offering	5,750,000	95,795	8,124,931	-	-	-	-	8,220,726
Balances at September 30, 2020	22,647,306	$377,304	$10,649,611	$ 1,874,007	$ 56,244,100	(411,487)	$(6,151,096)	$ 62,993,926
Net income (loss)	-	-	-	-	(6,217,237)	-	-	(6,217,237)
Purchase of treasury stock	-	-	-	-	-	(1,229)	(2,741)	(2,741)
Restricted stock awards	-	-	801,200	-	-	-	-	801,200
Dividends declared ($0.04 per share)	-	-	-	-	(1,060,443)	-	-	(1,060,443)
Distribution of restricted stock to officers and directors	-	-	(369,260)	-	-	24,171	368,404	(856)
Distribution of deferred directors' compensation	24,545	410	339,913	(340,322)	-	-	-	1
Increase in deferred directors' compensation charged to expense	-	-	-	234,466	-	-	-	234,466
Equity issued to acquire assets	3,702,582	61,685	10,210,603					10,272,288
Equity offering	6,175,000	102,875	10,985,981	-	-	-	-	11,088,856
At-the-market offering	221,000	3,682	595,597	-	-	-	-	599,279
Balances at September 30, 2021	32,770,433	$545,956	$33,213,645	$ 1,768,151	$ 48,966,420	(388,545)	$(5,785,433)	$ 78,708,739
Net income (loss)	-	-	-	-	20,409,272	-	-	20,409,272
Purchase of treasury stock	-	-	-	-	-	(700)	(1,855)	(1,855)
Restricted stock awards	-	-	2,211,673	-	-	-	-	2,211,673
Dividends declared ($0.065 per share)	-	-	-	-	(2,257,901)	-	-	(2,257,901)
Distribution of restricted stock to officers and directors	115,373	1,922	(178,481)	-	-	12,013	178,681	2,122
Distribution of deferred directors' compensation	61,452	1,024	462,736	(463,760)	-	-	-	-
Increase in deferred directors' compensation charged to expense	-	-	-	191,852	-	-	-	191,852
Equity issued to acquire assets	1,519,481	25,315	3,484,686	-	-	-	-	3,510,001
At-the-market offering	1,310,013	21,824	4,982,792	-	-	-	-	5,004,616
Balances at September 30, 2022	35,776,752	$596,041	$44,177,051	$ 1,496,243	$ 67,117,791	(377,232)	$(5,608,607)	$107,778,519

See accompanying notes.

PHX Minerals Inc.
Statements of Cash Flows

	Year ended September 30, 2022	2021	2020
Operating Activities			
Net income (loss)	$ 20,409,272	$ (6,217,237)	$ (23,952,037)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	7,278,118	7,745,804	11,313,783
Impairment of producing properties	14,565	50,475	29,904,528
Provision for deferred income taxes	1,242,000	(985,101)	(4,647,000)
Gain from leasing fee mineral acreage	(466,341)	(421,915)	(685,927)
Proceeds from leasing fee mineral acreage	688,207	441,653	701,948
Net (gain) loss on sales of assets	(4,423,646)	(309,348)	(3,973,321)
ESOP contribution expense	-	-	103,104
Directors' deferred compensation expense	191,852	234,466	228,408
Total (gain) loss on derivative contracts	16,833,078	16,202,489	(907,419)
Cash receipts (payments) on settled derivative contracts	(2,796,250)	(11,925,669)	4,109,210
Restricted stock awards	2,211,673	801,200	743,897
Loss on debt extinguishment	-	260,236	-
Other	87,353	(11,099)	(2,611)
Cash provided (used) by changes in assets and liabilities:			
Natural gas, oil and NGL sales receivables	(6,723,292)	(3,485,762)	1,434,426
Refundable (payable) income taxes	2,413,942	1,391,285	(2,299,785)
Other current assets	250,568	(436,401)	(89,931)
Accounts payable	(10,305)	(151,875)	1,308,731
Other non-current assets	(380,964)	(86,282)	(1,044,680)
Income taxes payable	161,808	-	-
Accrued liabilities	550,012	845,168	(1,139,029)
Total adjustments	17,122,378	10,159,324	35,058,332
Net cash provided by operating activities	37,531,650	3,942,087	11,106,295
Investing Activities			
Capital expenditures	$ (552,638)	$ (733,172)	$ (403,136)
Acquisition of minerals and overriding royalty interests	(43,525,236)	(20,624,347)	(10,288,250)
Net proceeds from sales of assets	13,217,844	988,600	4,228,868
Net cash provided (used) by investing activities	(30,860,030)	(20,368,919)	(6,462,518)
Financing Activities			
Borrowings under Credit Facility	21,300,000	26,300,000	6,061,725
Payments of loan principal	(10,500,000)	(37,550,000)	(12,736,725)
Net proceeds from equity issuance	5,006,538	11,688,137	8,220,726
Cash receipts from (payments on) off-market derivative contracts	(19,260,104)	8,800,000	-
Purchases of treasury stock	(1,855)	(2,741)	(7,635)
Payments of dividends	(2,257,901)	(1,060,448)	(1,652,164)
Net cash provided (used) by financing activities	(5,713,322)	8,174,948	(114,073)
Increase (decrease) in cash and cash equivalents	958,298	(8,251,884)	4,529,704
Cash and cash equivalents at beginning of year	2,438,511	10,690,395	6,160,691
Cash and cash equivalents at end of year	$ 3,396,809	$ 2,438,511	$ 10,690,395
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ 997,085	$ 1,021,142	$ 1,306,967
Income taxes paid (net of refunds received)	$ 384,249	$ (1,391,225)	$ (1,342,275)
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ -	$ -	$ 4
Gross additions to properties and equipment	$ 46,791,346	$ 31,485,015	$ 10,701,284
Value of shares used for acquisitions	(3,510,001)	(10,272,288)	-
Net (increase) decrease in accounts payable for properties and equipment additions	796,529	144,792	(9,898)
Capital expenditures and acquisitions	$ 44,077,874	$ 21,357,519	$ 10,691,386

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

The Company's principal line of business is maximizing the value of its existing mineral and royalty assets through active management and expanding its asset base through acquisitions of additional mineral and royalty interests. The Company owns mineral and leasehold properties and other natural gas and oil interests, which are all located in the contiguous United States, primarily in Oklahoma, Texas, Louisiana, North Dakota and Arkansas, with properties located in several other states. The Company's natural gas, oil and NGL production is from interests in 6,362 wells located principally in Oklahoma, Louisiana, Texas, Arkansas and North Dakota. The Company does not operate any wells. Approximately 66%, 26% and 8% of natural gas, oil and NGL revenues were derived from the sale of natural gas, oil and NGL, respectively, in 2022. Approximately 78%, 12% and 10% of the Company's total sales volumes in 2022 were derived from natural gas, oil and NGL, respectively. Substantially all the Company's natural gas, oil and NGL production is sold through the operators of the wells.

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 natural gas, crude oil and NGL 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 natural gas, crude oil and NGL 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 natural gas, crude oil and NGL prices as estimated by management are used. Natural gas, crude oil and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Management uses projected future natural gas, crude oil and NGL pricing assumptions to prepare estimates of natural gas, crude oil and NGL reserves used in formulating management's overall operating decisions.

As a non-operator of working, royalty and mineral interests, the Company receives actual natural gas, oil and NGL sales volumes and prices more than a month after the information is available to the operators of the wells. Because of the delay in information, the most current available production data is gathered from the appropriate operators, as well as public and private sources, and natural gas, oil and NGL index prices are used to estimate the accrual of revenue on these wells. If information is not available from an outside source, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The natural gas, oil and NGL 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 natural gas, oil and NGL. These variables could lead to an over or under accrual of natural gas, oil and NGL at the end of any particular quarter. Based on past history, the Company's estimated accrual has been materially accurate.

Basis of Presentation

Certain reclassifications have been made to prior period financials to conform to the current year presentation. These reclassifications have no impact on previous reported total assets, total liabilities, net loss, stockholders' equity, or operating cash flows.

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.

Natural Gas, Oil and NGL Sales

The Company sells natural gas, oil and NGL to various customers, recognizing revenues as natural gas, oil and NGL is produced and sold.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Company's accounts receivable are due from purchasers (operators) of natural gas, oil and NGL. Natural gas, oil and NGL 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 natural gas, oil and NGL 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 2022, 2021, and 2020 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.

Natural Gas and Oil Producing Activities

The Company follows the successful efforts method of accounting for natural gas and oil producing activities. For working interest properties, 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. Natural gas and oil 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 natural gas, oil or NGL 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 utilizes derivative contracts to reduce its exposure to short-term fluctuations in the price of natural gas and oil. These derivatives are recorded at fair value on the balance sheet. The Company has elected not to complete the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges.

Properties and Equipment

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of the costs of producing natural gas and oil 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. Leasehold costs for working interest properties 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 natural gas and oil properties include non-producing minerals, which had a net book value of $43,223,165 and $32,542,709 at September 30, 2022 and 2021, respectively, consisting of perpetual ownership of mineral interests in several states, with 60% of the acreage in Oklahoma, Texas, Louisiana, North Dakota and Arkansas. As mentioned, these mineral rights are perpetual and have been accumulated over the 96-year life of the Company. There are approximately 178,318 net acres of non-producing minerals in more than 5,727 tracts owned by the Company. An average tract contains approximately 30 acres. Since inception, the Company has continually generated an interest in several thousand natural gas and oil wells using its ownership of the fee mineral acres as an ownership basis. There continues to be drilling and leasing activity on these mineral interests each year. Non-producing minerals are considered a long-term investment by the Company, as they do not expire (unlike natural gas and oil leases) and based on past history and experience, management has concluded that a long-term straight-line amortization over 33 years is appropriate. 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 the Company's 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 a 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 the Company's minerals, and future development will deplete these assets over a long period. The straight-line amortization over a 20-year period is appropriate for producing minerals, because current and future development will deplete these assets over a lengthy period that represents the estimated economic life.

Capitalized Interest

During 2022, 2021, and 2020, no interest was capitalized. Interest of $1,164,992, $995,127 and $1,286,788, respectively, was charged to expense during those periods.

Accrued Liabilities

The following table shows the balances for the years ended September 30, 2022 and 2021, relating to the Company's accrued liabilities:

	Year Ended September 30,			
	2022		2021	
Accrued compensation	$	1,296,471	$	982,259
Revenues payable		263,225		275,981
Accrued ad valorem		190,216		245,116
Other		282,363		305,981
Total accrued liabilities	$	2,032,275	$	1,809,337

The increase in accrued compensation in 2022 is primarily due to the short-term incentive compensation driven by Company performance.

Asset Retirement Obligations

The Company owns interests in natural gas and oil 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 asset retirement obligations.

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 the Company being responsible for its proportionate share of the costs involved (on working interest wells only). The Company 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, 2022 and 2021, 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 recorded the fair market value of the stock contributed into its ESOP as expense.

Restricted stock awards to officers and employees provide for either cliff vesting at the end of three years from the date of the awards or time vesting ratably over a three year period. These restricted stock awards can be granted based on service time only (time-based), subject to certain share price performance standards (market-based) or subject to company performance standards (performance-based). Restricted stock awards to the non-employee directors provide for annual 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 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, 2022, was a 17% provision, as compared to a 9% benefit for the year ended September 30, 2021.

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 2019.

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 the fiscal years ended September 30, 2022, 2021, and 2020, the Company’s interest and penalties were not material. The Company does not believe it has any material uncertain tax positions.

Recent Accounting Pronouncements

Standard	Description	Date of Adoption	Impact on Financial Statements or Other Significant Matters
Adoption of New Accounting Pronouncements			
ASU 2016-02, *Leases (Topic 842)*	This update will supersede the lease requirements in Topic 840, *Leases*, by requiring lessees to recognize lease assets and lease liabilities classified as operating leases on the balance sheet.	Q1 2020	See Note 2. Leases and Commitments for further details related the Company’s adoption of this standard.
ASU 2018-11, *Leases (Topic 842), Targeted Improvements* and ASC 842	This update will allow entities to apply the transition provisions of the new standard at the adoption date instead of at the earliest comparative period presented in the financial statements and will allow entities to continue to apply the legacy guidance in Topic 840, including disclosure requirements, in the comparative period presented in the year the new leases standard is adopted. Entities that elect this option would still adopt the new leases standard using a modified retrospective transition method but would recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if any, rather than in the earliest period presented.	Q1 2020	See Note 2. Leases and Commitments for further details related the Company’s adoption of this standard.
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.	Q1 2021	The adoption of this update did not have a material impact on the Company's balance sheet, statement of operations or liquidity. The Company's credit losses on natural gas, oil and NGL sales receivables are immaterial.
ASU 2019-12, *Simplifying the Accounting for Income Taxes*.	This standard is intended to clarify and simplify the accounting for income taxes by removing certain exceptions and amending existing guidance.	Q1 2022	The adoption of this update did not have a material impact on the Company's financial statements and related disclosures.

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

2. LEASES AND COMMITMENTS

Assessment of Leases

The Company determines if an arrangement is a lease at inception by considering whether (i) explicitly or implicitly identified assets have been deployed in the agreement and (ii) the Company obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the agreement. As of September 30, 2022, none of the Company's leases were classified as financing leases. Operating lease liabilities represent the Company's obligation to make lease payments arising from the lease. The Company entered into a seven-year lease for office space during the quarter ended March 31, 2020, with a commencement date in August 2020. The associated lease liability and ROU asset at September 30, 2022, were $789,339 and $519,334, respectively. The Company has a lease incentive asset of $244,253, which is included in Other, net on the Company's balance sheets. Additionally, the Company entered into a new five-year lease for office space during the quarter ended March 31, 2022, with a commencement date in July 2022. The associated lease liability and ROU asset at September 30, 2022, were $409,903 and $219,797, respectively. The Company has a lease incentive asset of $146,548, which is included in Other, net on the Company's balance sheets.

ROU assets represent the Company's right to use an underlying asset for the lease term, and operating lease liabilities represent the Company's obligation to make payments arising from the lease. ROU assets are recognized at commencement date and consist of the present value of remaining lease payments over the lease term, initial direct costs and prepaid lease payments less any lease incentives. Operating lease liabilities are recognized at commencement date based on the present value of remaining lease payments over the lease term. The Company uses the implicit rate, when readily determinable, or its incremental borrowing rate based on the information available at commencement date to determine the present value of lease payments.

The lease terms may include periods covered by options to extend the lease when it is reasonably certain that the Company will exercise that option and periods covered by options to terminate the lease when it is not reasonably certain that the Company will exercise that option. Lease expense for lease payments will be recognized on a straight-line basis over the lease term. The Company made an accounting policy election to not recognize leases with terms, including applicable options, of less than twelve months on the Company's balance sheets and recognize those lease payments in the Company's Statements of Operations on a straight-line basis over the lease term. In the event that the Company's assumptions and expectations change, it may have to revise its ROU assets and operating lease liabilities.

The following table represents the maturities of the operating lease liabilities as of September 30, 2022:

2023	$	256,794
2024		265,097
2025		268,651
2026		276,953
2027		255,948
Thereafter		-
Total lease payments	$	1,323,443
Less: Imputed interest		(124,201)
Total	$	1,199,242

3. REVENUES

Natural gas and oil derivative contracts

See Note 12 for discussion of the Company's accounting for derivative contracts.

Revenues from Contracts with Customers

Natural gas, oil and NGL sales

Sales of natural gas, oil and NGL are recognized when production is sold to a purchaser and control has transferred. 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 natural gas, oil and NGL revenues

The following table presents the disaggregation of the Company's natural gas, oil and NGL revenues for the year ended September 30, 2022.

	Year Ended September 30, 2022		
	Royalty Interest	Working Interest	Total
Natural gas revenue	$ 30,837,464	$ 14,930,201	$ 45,767,665
Oil revenue	10,851,353	7,279,566	18,130,919
NGL revenue	2,795,655	3,166,392	5,962,047
Natural gas, oil and NGL sales	$ 44,484,472	$ 25,376,159	$ 69,860,631

Performance obligations

The Company satisfies the performance obligations under its natural gas, oil and NGL 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

Natural gas, oil and NGL 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 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 natural gas, oil and NGL sales receivables line item on the Company's balance sheets. The difference between the Company's estimates and the actual amounts received for natural gas, oil and NGL sales is recorded in the quarter that payment is received from the third party. For the years ended September 30, 2022, 2021, and 2020, revenue recognized in these reporting periods related to performance obligations satisfied in prior reporting periods for existing wells was considered a change in estimate.

4. INCOME TAXES

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

	2022	2021	2020
Current:			
Federal	$ 2,522,000	$ 315,050	$ (3,642,000)
State	438,000	19,000	-
	2,960,000	334,050	(3,642,000)
Deferred:			
Federal	845,000	(824,000)	(3,611,000)
State	397,000	(161,101)	(1,036,000)
	1,242,000	(985,101)	(4,647,000)
	$ 4,202,000	$ (651,051)	$ (8,289,000)

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:

	2022	2021	2020
Provision (benefit) for income taxes at statutory rate	$ 5,168,366	$ (1,429,291)	$ (6,765,705)
Change in valuation allowance	(1,313,271)	1,228,899	96,000
Percentage depletion	(602,490)	(412,650)	(258,300)
State income taxes, net of federal provision (benefit)	863,042	(176,960)	(939,310)
Effect of NOL Carryback Rate	-	-	(610,803)
Restricted stock tax benefit	59,000	76,000	58,000
Deferred directors' compensation benefit	64,000	54,000	79,000
Law change	(56,094)	47,000	-
Other	19,447	(38,049)	52,118
	$ 4,202,000	$ (651,051)	$ (8,289,000)

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:

	2022	2021
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 5,121,376	$ 4,090,017
Derivative contracts	-	-
Total deferred tax liabilities	5,121,376	4,090,017
Deferred tax assets:		
State net operating loss carry forwards	14,737	238,439
Federal net operating loss carry forwards	-	-
Statutory depletion carryover	-	286,440
Asset retirement obligations	337,247	483,990
Deferred directors' compensation	331,395	390,683
Restricted stock expense	705,195	303,674
Derivative contracts	2,072,530	3,278,067
Other	88,095	91,717
Total deferred tax assets	3,549,199	5,073,010
Deferred tax asset valuation allowance	-	1,251,096
State NOL valuation allowance	13,729	75,803
Net deferred tax (assets) liabilities	$ 1,585,906	$ 343,906

Included in state net operating loss carry forwards at September 30, 2022, the Company had a deferred tax asset of $14,737 related to Arkansas state income tax net operating loss ("AR NOL") carry-forwards, which begin to expire in 2023. The Company has a valuation allowance of $13,729 for the AR NOLs, as it is more likely than not that it will not be utilized before expiration.

The federal Coronavirus Aid, Relief, and Economic Security Act ("CARES Act") was enacted on March 27, 2020. The CARES Act provides relief to corporate taxpayers by permitting a five-year carryback of 2018-2020 Net Operating Losses ("NOLs"), removing the 80% limitation on the carryback of those NOLs, increasing the Section 163(j) 30% limitation on interest expense deductibility to 50% of adjusted taxable income for 2019 and 2020, and accelerates refunds for minimum tax credit carryforwards, along with a few other provisions. On July 28, 2020, final regulations were issued under Section 163(j) which modified the calculation under the previous proposed regulations of adjusted taxable income for purposes of the 50% limitation on interest expense. Under the final regulations, depreciation, amortization, and depletion capitalizable under Section 263A is now added back to tentative taxable income. This change allows all interest expense to be deductible for 2020 and reduces the associated deferred tax asset to zero. In fiscal 2021, the Company received a tax refund associated with the AMT credits totaling $1.4 million, which was accelerated due to the CARES Act. In fiscal 2022, the Company received $2.2 million associated with the carryback of the 2020 federal net operating loss.

5. DEBT

On September 1, 2021, the Company entered into a $100,000,000 credit facility (the "Credit Facility") with a group of banks headed by Independent Bank, which replaced the Company's prior credit facility with BOKF, NA dba Bank of Oklahoma ("BOKF"), as administrative agent, which the Company repaid in full and terminated. The Credit Facility has a current borrowing base of $50,000,000 as of September 30, 2022, and a maturity date of September 1, 2025. The Credit Facility is secured by the Company's personal property and at least 80% of the total value of the proved, developed and producing oil and gas properties. The interest rate is based on either (a) the Secured Overnight Financing Rate ("SOFR") plus an applicable margin ranging from 2.750% to 3.750% per annum based on the Company's Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on the Company's Borrowing Base Utilization. The election of Independent Bank prime or SOFR is at the Company's discretion. The interest rate spread from Independent Bank prime or SOFR will be charged based on the ratio of the loan balance to the borrowing base. The interest rate spread from SOFR or the prime rate increases as a larger percent of the borrowing base is advanced. At September 30, 2022, the effective interest rate was 5.93%.

The Company's debt is recorded at the carrying amount on its balance sheets. The carrying amount of the Credit Facility approximates fair value because the interest rates are reflective of market rates. Debt issuance costs associated with the Credit Facility are presented in Other, net on the Company's balance sheets. Total debt issuance cost net of amortization as of September 30, 2022, was $336,232. The debt issuance cost is amortized over the life of the Credit Facility.

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 natural gas and oil properties. The Credit Facility 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, make fundamental changes, and engage in certain transactions with affiliates. The Credit Agreement also restricts the Company's ability to make certain restricted payments if before or after the Restricted Payment (i) the Available Commitment is less than ten percent (10%) of the Borrowing Base or (ii) the Leverage Ratio on a pro forma basis is greater than 2.50 to 1.00. In addition, the Company is required to maintain certain financial ratios, a current ratio (as described in the Credit Agreement) of no less than 1.0 to 1.0 and a funded debt to EBITDAX (as defined in the Credit Agreement) of no more than 3.5 to 1.0 based on the trailing twelve months. At September 30, 2022, the Company was in compliance with the covenants of the Credit Facility, had $28,300,000 outstanding, and had $21,700,000 of borrowing base availability under the Credit Facility. All capitalized terms in this description of the Credit Facility that are not otherwise defined in this Annual Report have the meaning assigned to them in the Credit Agreement.

6. STOCKHOLDERS' EQUITY

In May 2014, the Board adopted stock repurchase resolutions (the "Repurchase Program") to allow management, at its discretion, to purchase the Company's Common Stock as treasury shares up to an amount equal to the aggregate number of shares of Common Stock awarded pursuant to the 2010 Restricted Stock Plan ("2010 Stock Plan"), as amended, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

Effective in May 2018, the Board approved an amendment to the Company's existing stock Repurchase Program. As amended, the Repurchase Program continues to allow the Company to repurchase up to $1.5 million of the Company's Common Stock at management's discretion. The Board added language to clarify that this is intended to be an evergreen program as the repurchase of an additional $1.5 million of the Company's Common Stock is authorized and approved whenever the previous amount is utilized. In addition, 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 2010 Stock Plan, as amended, (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.

On August 25, 2021, the Company entered into an At-The-Market Equity Offering Sales Agreement, pursuant to which the Company may offer and sell from time to time up to 3 million shares of Common Stock.

7. EARNINGS (LOSS) PER SHARE ("EPS")

Basic and diluted earnings (loss) per common share is calculated using net income (loss) divided by the weighted average number of shares of Common Stock outstanding, including unissued, vested directors' deferred compensation shares of 219,286, 183,334 and 154,142, respectively, during the 2022, 2021, and 2020 periods.

For the years ended September 30, 2021 and 2020, the Company did not include restricted stock in the diluted EPS calculation because the effect would have been antidilutive. The average shares outstanding of restricted stock excluded from the diluted EPS calculation was 141,690 and 80,809 for the years ended September 30, 2021 and 2020, respectively.

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

	Year Ended September 30, 2022	2021	2020
Basic EPS			
Numerator:			
Basic net income (loss)	$ 20,409,272	$ (6,217,237)	$ (23,952,037)
Denominator:			
Common Shares	34,184,212	25,742,202	16,856,792
Unissued, directors' deferred compensation shares	219,286	183,334	154,142
Basic weighted average shares outstanding	34,403,498	25,925,536	17,010,934
Basic EPS	$ 0.59	$ (0.24)	$ (1.41)
Diluted EPS			
Numerator:			
Basic net income (loss)	$ 20,409,272	$ (6,217,237)	$ (23,952,037)
Diluted net income (loss)	20,409,272	(6,217,237)	(23,952,037)
Denominator:			
Basic weighted average shares outstanding	34,403,498	25,925,536	17,010,934
Effects of dilutive securities:			
Unvested restricted stock	156,812	-	-
Diluted weighted average shares outstanding	34,560,310	25,925,536	17,010,934
Diluted EPS	$ 0.59	$ (0.24)	$ (1.41)

8. 401K PLAN AND EMPLOYEE STOCK OWNERSHIP PLAN ("ESOP")

The Company's ESOP was established in 1984 and is a tax qualified, defined contribution plan. Company contributions were made at the discretion of the Board, and, to date, all contributions have been made in shares of Company Common Stock. For contributions of Common Stock, the Company recorded as expense the fair market value of the stock contributed. Effective January 1, 2021, the Company terminated the ESOP and established a new defined contribution 401K only plan. All ESOP participants were fully vested in all Company Common Stock held in their accounts, and those shares were transferred to their new 401K accounts. The Company began matching up to 5% of 401K contributions in cash starting January 1, 2021.

Contributions to the plans consisted of:

Year	Plan	Shares	Amount
2022	401K	-	$ 85,444
2021	401K	-	$ 79,015
2020	ESOP	72,101	$ 103,104

9. DEFERRED COMPENSATION PLAN FOR DIRECTORS

Annually, independent directors may elect to be included in the Company's 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, 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 at each quarter end. 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, 2022, there were 241,353 shares recorded under the Plan. The deferred balance outstanding at September 30, 2022, under the Plan was $1,496,243. Expenses totaling $191,852, $234,466 and $228,408 were charged to the Company's results of operations for the years ended September 30, 2022, 2021, and 2020, respectively, and are included in general and administrative expense in the accompanying Statements of Operations.

10. RESTRICTED STOCK PLAN AND LONG-TERM INCENTIVE PLAN

In March 2010, stockholders approved the Company's 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. In March 2020, stockholders approved an amendment to increase the number of shares of Common Stock reserved for issuance under the 2010 Stock Plan to 750,000 shares. 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 (time-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 or the Company's authorized but unissued shares.

In December 2010, the Company also began awarding shares of the Company's Common Stock, subject to certain share price performance standards (market-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.

In May 2014, the Company also began awarding shares of the Company's Common Stock as restricted stock (time-based) to its non-employee directors. The restricted stock vests annually. The fair value of the shares is 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 or the Company's authorized but unissued shares.

In March of 2021, stockholders approved the PHX Minerals Inc. 2021 Long-Term Incentive Plan (the "LTIP"). The terms and conditions of awards granted under the Company's 2010 Stock Plan prior to the LTIP are not affected by the adoption of the LTIP. The LTIP expressly prohibits the payment of dividends or dividend equivalents on any award before the date on which the award vests. Awards under the LTIP will be subject to any clawback or recapture policy that the Company may adopt from time to time or any clawback or recapture provisions set forth in an award agreement.

On January 5, 2021, the Company awarded 303,750 market-based shares of the Company's Common Stock as restricted stock to certain officers. The restricted stock vests at the end of a three-year period and contains non-forfeitable rights to receive dividends and voting rights during the vesting period. The market-based shares that do not meet certain market performance criteria at a certain date are forfeited. The market-based shares had a fair value on their award date of $826,457. The fair value of the market-based awards will be recognized as compensation expense ratably over the vesting period. The fair value of the market-based shares on their award date is calculated by simulating the Company's stock prices as compared to the S&P Oil & Gas Exploration & Production ETF (XOP) prices utilizing a Monte Carlo model covering the market performance period (December 18, 2020, through December 18, 2023).

On March 22, 2021, the Company awarded 125,000 time-based shares of the Company's Common Stock as restricted stock to its non-employee directors. The shares issued as restricted stock contain voting rights during the vesting period but do not include the right to dividends prior to the stock vesting. The restricted stock vests on December 31, 2021. These time-based shares had a fair value on their award date of $396,252.

On March 2, 2022, the Company awarded shares of Common Stock in the form of time-based and market-based restricted stock to the directors, employees and officers of the Company. Non-employee directors received 138,249 time-based shares with a fair value on the award date of $387,095. These shares vest in December 2022. Officers were awarded 402,086 market-based shares with a fair value on their award date of $1,679,757. Upon vesting, the market-based shares that do not meet certain performance criteria are forfeited. Both employees and certain officers were also awarded 126,013 time-based shares with a fair value on the award date of $352,838. The shares issued to employees time-vest ratably over a three-year period ending in December 2024, and the shares awarded to the officers cliff vest at the end of a three-year period ending in December 2024. All shares awarded on March 2, 2022, have voting rights during the vesting period and do not include the right to dividends prior to vesting.

On April 1, 2022, the Company awarded shares of common stock in the form of time-based restricted stock to a new director. The non-employee director received 20,737 time-based shares with a fair value on the award date of $62,004. These shares vest in December of 2022, contain voting rights during the vesting period, and do not include the right to dividends prior to vesting.

Compensation expense for the restricted stock awards is recognized in G&A. Forfeitures of awards are recognized when they occur.

The following table summarizes the Company's pre-tax compensation expense for the years ended September 30, 2022, 2021. and 2020, related to the Company's market-based, time-based and performance-based restricted stock:

	Year Ended September 30,		
	2022	2021	2020
Market-based, restricted stock	$ 1,018,136	$ 247,601	$ 295,397
Time-based, restricted stock	$ 730,303	$ 553,599	448,500
Performance-based, restricted stock	463,234	-	-
Total compensation expense	$ 2,211,673	$ 801,200	$ 743,897

A summary of the Company's unrecognized compensation cost for its unvested market-based, time-based and 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)
Market-based, restricted stock	$ 1,308,130	1.30
Time-based, restricted stock	433,434	1.43
Performance-based, restricted stock	6,376	0.20
Total	$ 1,747,940	

Upon vesting, shares are expected to be issued out of shares held in treasury and authorized but unissued shares.

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

	Market-Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value	Time-Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value	Performance-Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value
Unvested shares as of September 30, 2019	46,670	$ 10.21	18,707	$ 17.54	-	$ -
Granted	39,579	8.83	102,154	9.21	39,579	9.04
Vested	-	-	(20,410)	13.35	-	-
Forfeited	(24,779)	11.34	(9,929)	13.93	(4,765)	9.35
Unvested shares as of September 30, 2020	61,470	$ 8.87	90,522	$ 9.49	34,814	$ 8.99
Granted	303,750	2.72	125,000	3.17	-	-
Vested	-	-	(9,860)	14.08	-	-
Forfeited	(9,071)	11.34	(2,562)	13.00	-	-
Unvested shares as of September 30, 2021	356,149	$ 3.56	203,100	$ 5.33	34,814	$ 8.99
Granted	402,086	4.18	284,999	2.81	-	-
Vested	-	-	(127,386)	3.41	-	-
Forfeited	(17,585)	8.16	(6,855)	6.92	-	-
Unvested shares as of September 30, 2022	740,650	3.79	353,858	3.97	34,814	8.99

The intrinsic value of the vested shares in 2022 was $277,573.

11. PROPERTIES AND EQUIPMENT

Impairment

During the year ended September 30, 2022, the Company recorded no impairment provisions on producing properties and $14,565 on wells that the Company wrote off.

During the year ended September 30, 2021, the Company recorded impairment of $37,879 on producing properties and $12,596 on wells that the Company wrote off.

During the quarter ended March 31, 2020, impairment of $19.3 million and $7.3 million was recorded on our Fayetteville Shale and Eagle Ford fields, respectively. The remaining $2.7 million of impairment was taken on other producing assets. The discounted cash flows of the properties were prepared using NYMEX strip pricing as of March 31, 2020, using a discount rate of 10% for proved developed and assigning no value to undeveloped locations. The Fayetteville Shale assets are dry-gas assets of which the Company acquired a portion in 2011. Low natural gas prices at March 31, 2020, were the primary reason for impairment in this field. The impairment of the Eagle Ford assets at March 31, 2020, was due to the decline in commodity prices over fiscal year 2020.

A further reduction in natural gas, oil and NGL prices or a decline in reserve volumes may lead to additional impairment in future periods that may be material to the Company.

Divestitures

Quarter Ended	Net mineral acres[(1)]/ Wellbores[(2)]	Sale Price [(4)]	Gain/(Loss) [(4)]	Location
September 30, 2022				
	5 wellbores	$0.1million	$-	OK
	210 wellbores	$5.0million	$3.5million	AR
	87 acres	$0.1million	$0.1million	TX
	9 wellbores	$0.2million	$0.1million	ND
June 30, 2022				
	43 acres	$0.1million	$0.1million	TX
	9 wellbores	$0.3million	$0.1million	OK
	83 acres	$0.1million	$0.1million	OK
	16 wellbores	$0.1million	$-	OK
	2 wellbores	$0.1million	$0.1million	OK
	2,255 acres	$0.3million	$0.3million	AR / OK / TX
March 31, 2022				
	7,071 acres	$1.6million	$1.6million	NM / TX
	130 acres	$0.5million	$0.5million	TX
December 31, 2021				
	98 wellbores	$2.0million	($3.5)million	OK
	95 wellbores	$0.5million	$0.2million	OK / TX
	499 wellbores	$2.1million	$1.1million	AR
September 30, 2021				
	No significant divestitures			
June 30, 2021				
	2,857 acres	$0.3million	$0.2million	Central Basin Platform, TX
March 31, 2021				
	No significant divestitures			
December 31, 2020				
	No significant divestitures			

(1) Number of net mineral acres sold.
(2) Number of gross wellbores associated with working interests sold.
(3) Excludes immaterial divestitures.
(4) Sales price and gain(loss) is net of purchase price adjustment.

Acquisitions

Quarter Ended [4]	Net royalty acres [1][2]	Cash	Number of shares issued [3]	Total Purchase Price [1]	Area of Interest
September 30, 2022					
	63	$0.7million	-	$0.7million	Haynesville / LA
	17	$0.2million	-	$0.2million	SCOOP / OK
	85	$1.5million	-	$1.5million	Haynesville / LA
	214	$3.0million	-	$3.0million	Haynesville / LA
	110	$1.0million	-	$1.0million	Haynesville / LA
	295	$5.5million	-	$5.5million	Haynesville / LA
	140	$1.7million	-	$1.7million	SCOOP / OK
June 30, 2022					
	60	$0.6million	-	$0.6million	SCOOP / OK
	46	$0.8million	-	$0.8million	Haynesville / LA
	56	$0.4million	-	$0.4million	Haynesville / LA
	88	$0.9million	-	$0.9million	SCOOP / OK
	503	$5.0million	-	$5.0million	Haynesville / LA, TX
	92	$0.6million	-	$0.6million	Haynesville / LA
	25	$0.3million	-	$0.3million	Haynesville / LA
	68	$0.5million	-	$0.5million	SCOOP / OK
March 31, 2022					
	58	$0.5million	-	$0.5million	SCOOP / OK
	500	$6.4million	-	$6.4million	Haynesville / LA
	68	$0.7million	-	$0.7million	Haynesville / TX
	166	$1.3million	-	$1.3million	SCOOP / OK
	33	$0.4million	-	$0.4million	Haynesville / TX
December 31, 2021					
	426	$5.8million	-	$5.8million	Haynesville / LA
	847	$0.6million	1,519,481	$4.1million	Haynesville / LA
	172	$1.4million	-	$1.4million	SCOOP / OK
	103	$0.6million	-	$0.6million	Haynesville / TX
	116	$1.7million	-	$1.7million	Haynesville / LA
	220	$1.2million	-	$1.2million	SCOOP / OK
September 30, 2021					
	817	$0.7million	2,349,207	$7.3million	Haynesville / LA, TX
June 30, 2021					
	262	$1.3million	-	$1.3million	Haynesville / LA
	131	$1.0million	-	$1.0million	Haynesville / TX
	2,514	$9.5million	1,200,000	$13.0million	SCOOP / OK
March 31, 2021					
	No significant acquisitions				
December 31, 2020					
	142	$1.0million	-	$1.0million	Haynesville / TX
	184	$0.8million	-	$0.8million	Haynesville / TX
	386	$3.5million	-	$3.5million	Haynesville / TX
	297	$2.0 million	153,375	$2.3 million	SCOOP / OK

(1) Excludes subsequent closing adjustments and insignificant acquisitions.
(2) An estimated net royalty equivalent was used for the minerals included in the net royalty acres.
(3) The Company's policy is to classify all costs associated with equity issuances as financial costs in the Statements of Cash Flows.
(4) Presented in chronological order with most recent at top.

All purchases made in 2020, 2021, and 2022 were of mineral and royalty acreage and were accounted for as asset acquisitions.

Asset Retirement Obligations

The following table shows the activity for the years ended September 30, 2022 and 2021, relating to the Company's asset retirement obligations:

	2022	2021
Asset retirement obligations as of beginning of the year	$ 2,836,172	$ 2,897,522
Wells acquired or drilled	-	-
Wells sold or plugged	(1,027,030)	(189,459)
Accretion of discount	92,762	128,109
Asset retirement obligations as of end of the year	$ 1,901,904	$ 2,836,172

As a non-operator, the Company does not control the plugging of wells in which it has a working interest and is not involved in the negotiation of the terms of the plugging contracts. This estimate relies on information gathered from outside sources as well as relevant information received directly from operators.

12. 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 natural gas and oil. 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 natural gas and oil production, provide only partial price protection against declines in natural gas and oil prices and may limit the benefit of future increases in prices.

On September 2, 2021, the Company settled all of its derivative contracts consisting of both swaps and costless collars with BOKF by paying $8.8 million. On September 3, 2021, the Company entered into new derivative contracts with BP Energy Company ("BP") that had similar terms to the contracts settled with BOKF and received a payment of $8.8 million from BP. The new derivative contracts consisted of all fixed swap contracts and are secured under the Company's Credit Facility with Independent Bank. Management concluded that the financing element of the new derivative contracts with BP was other than insignificant due to the off-market terms of the fixed swap price. Due to the financing element, the Company is required to report all cash flows associated with these derivative contracts as "cash flows from financing activities" in the statement of cash flows. This requirement relates to all cash flows from these derivatives and not just the portion of the cash flows relating to the financing element of the derivative. The derivative instruments have settled or will settle based on the terms below.

Derivative contracts in place as of September 30, 2022

Fiscal period	Contract total volume	Index	Contract average price
Natural gas costless collars			
2023	1,415,000 Mmbtu	NYMEX Henry Hub	$4.13floor/$7.69ceiling
2024	135,000 Mmbtu	NYMEX Henry Hub	$3.28floor/$5.98ceiling
Natural gas fixed price swaps			
2023	2,100,000 Mmbtu	NYMEX Henry Hub	$3.24
2024	380,000 Mmbtu	NYMEX Henry Hub	$3.41
Oil Costless Collars			
2023	15,000 Bbls	NYMEX WTI	$75.00floor/$96.00ceiling
Oil fixed price swaps			
2023	72,750 Bbls	NYMEX WTI	$63.65
2024	14,250 Bbls	NYMEX WTI	$74.91

The Company's fair value of derivative contracts was a net liability of $8,561,191 as of September 30, 2022, and a net liability of $13,784,467 as of September 30, 2021. Realized and unrealized gains and (losses) are recorded in gains (losses) on derivative contracts on the Company's Statement of Operations. Cash receipts in the following table reflect the gain or loss on derivative contracts which settled during the respective periods, and the non-cash gain or loss reflect the change in fair value of derivative contracts as of the end of the respective periods. The $8.8 million in cash received from BP in fiscal 2021 is a cash flow from a financing activity and is excluded from the table below.

	For the Year Ended September 30, 2022	2021	2020
Cash received (paid) on settled derivative contracts:			
Natural gas costless collars	$ (1,878,250)	$ (4,271,467)	$ 28,510
Natural gas fixed price swaps[1]	(9,065,100)	(1,862,801)	1,687,600
Oil costless collars	-	(2,047,098)	1,011,472
Oil fixed price swaps[1]	(3,590,210)	(3,744,303)	1,381,628
Cash received (paid) on settled derivative contracts, net	$ (14,533,560)	$ (11,925,669)	$ 4,109,210
Non-cash gain (loss) on derivative contracts:			
Natural gas costless collars	$ (1,044,958)	$ 706,015	$ (706,015)
Natural gas fixed price swaps	(1,954,719)	(3,624,108)	(1,535,122)
Oil costless collars	106,157	(63,169)	(538,022)
Oil fixed price swaps	594,002	(1,295,558)	(422,632)
Non-cash gain (loss) on derivative contracts, net	$ (2,299,518)	$ (4,276,820)	$ (3,201,791)
Gains (losses) on derivative contracts, net	$ (16,833,078)	$ (16,202,489)	$ 907,419

(1) For the year ended September 30, 2022, excludes $7,522,794 of cash paid to settle off-market derivative contracts that are not reflected on the Condensed Statements of Operations. Total cash paid related to off-market derivatives was $19,260,104 for the year ended September 30, 2022 and is reflected in the Financing Activities section of the Condensed Statements of Cash Flows.

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 on 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, 2022, and September 30, 2021. The Company has offset all amounts subject to master netting agreements on the Company's balance sheets at September 30, 2022 and September 30, 2021.

	9/30/2022 Fair Value Commodity Contracts				9/30/2021 Fair Value Commodity Contracts		
	Current Assets	Current Liabilities	Non-Current Assets	Non-Current Liabilities	Current Assets	Current Liabilities	Non-Current Liabilities
Gross amounts recognized	$ 924,258	$8,798,237	$ 124,983	$ 812,195	$ 17,395	$12,105,383	$1,696,479
Offsetting adjustments	(924,258)	(924,258)	(124,983)	(124,983)	(17,395)	(17,395)	-
Net presentation on Balance Sheets	$ -	$7,873,979	$ -	$ 687,212	$ -	$12,087,988	$1,696,479

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.

13. 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, 2022			
	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	$ -	$ (7,622,390)	$ -	$ (7,622,390)
Derivative Contracts - Collars	$ -	$ (938,801)	$ -	$ (938,801)

	Fair Value Measurement at September 30, 2021			
	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	$ -	$ (13,784,467)	$ -	$ (13,784,467)

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,					
	2022		2021		2020	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Producing Properties [(a)]	$ -	$ -	$ 587	$ 37,879	$ 5,288,710	$ 29,315,807

(a) At the end of each quarter, the Company assessed the carrying value of its producing properties for impairment if indicators of impairment existed at such time. 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 natural gas, oil and NGL 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. This table excludes impairments on properties that were written off in the amount of $14,565, $12,596 and $588,721 for the years ended September 30, 2022, 2021 and 2020, respectively.

At September 30, 2022, and September 30, 2021, 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 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.

14. INFORMATION ON NATURAL GAS AND OIL PRODUCING ACTIVITIES

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

The following table shows sales to major purchasers, by percentage, through various operators/purchasers during 2022, 2021 and 2020.

	2022	2021	2020
Company A	10%	14%	23%
Company B	5%	7%	6%

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

15. SUBSEQUENT EVENTS

Third Amendment to Credit Agreement

On December 7, 2022, the Company entered into a Third Amendment (the "Third Amendment") to the Credit Agreement. Pursuant to the terms of the Third Amendment, among other changes, (a) the borrowing base under the Credit Facility was reaffirmed at $50 million, which constitutes the periodic redetermination of the borrowing base for December 1, 2022 and is not deemed an unscheduled redetermination, (b) the required title percentage owed by the Company was decreased from 80% to 50% and (c) the required mortgage percentage owed by the Company was decreased from 80% to 75%.

The above description of the material terms and conditions of the Third Amendment does not purport to be complete and is qualified in its entirety by reference to the full text of the Third Amendment, which is filed as Exhibit 10.8 to this Annual Report on Form 10-K.

Acquisitions

Subsequent to September 30, 2022, the Company has closed on additional acquisitions of 930 net royalty acres located in the SCOOP and Haynesville plays for approximately $10.3 million funded through cash on hand and additional borrowings of $5 million.

Change in Fiscal Year and Amendment of Bylaws

On December 9, 2022, the Company's Board approved a change in fiscal year from the twelve months beginning October 1st and ending September 30th to the twelve months beginning January 1st and ending December 31st. The Company plans to file a transition report on Form 10-QT for the transition period from October 1, 2022 to December 31, 2022. The Company's fiscal year 2023 will begin January 1, 2023 and end December 31, 2023.

In order to reflect the change in fiscal year, the Company's Board has adopted an amendment to the Company's Bylaws, effective December 9, 2022. Section 7.08 of the Company's Bylaws has been amended to provide that the fiscal year of the Company shall consist of twelve (12) calendar months terminating on December 31st of each calendar year, rather than terminating on September 30th of each calendar year. Further, Section 7.08 of the Company's Bylaws has been amended to provide that the Board may further change the fiscal year of the Company, without amending the Bylaws, by resolution adopted by a majority of the whole Board at any special or regular meeting of the Board.

A copy of the Amended and Restated Bylaws of the Company is filed as Exhibit 3.2 to this Annual Report on Form 10-K.

Termination of a Material Definitive Contract

On December 12, 2022, the Company voluntarily terminated its At-The-Market Equity Offering Sales Agreement, dated August 25, 2021, as amended by Amendment No. 1 dated May 10, 2022 (the "ATM Agreement"), that was entered into with Stifel. Pursuant to the ATM Agreement, the Company was authorized to offer and sell, from time to time, through or to Stifel, up to 3,000,000 shares of Common Stock. During the term of the ATM Agreement, 1,531,013 shares of Common Stock were sold pursuant to the ATM Agreement for proceeds of approximately $5.9 million, net of commissions paid. The ATM Agreement was terminable at will by the Company at any time without penalty.

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

Aggregate Capitalized Costs

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

	2022	2021
Producing properties	$ 248,978,928	$ 319,984,874
Non-producing minerals	50,032,539	38,328,699
Non-producing leasehold	1,746,797	2,137,399
	300,758,264	360,450,972
Accumulated depreciation, depletion and amortization	(168,349,542)	(257,250,452)
Net capitalized costs	$ 132,408,722	$ 103,200,520

Costs Incurred

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

	2022	2021	2020
Property acquisition costs	$ 46,224,928	$ 30,963,579	$ 10,453,119
Development costs	156,752	518,058	273,825
	$ 46,381,680	$ 31,481,637	$ 10,726,944

Estimated Quantities of Proved Natural Gas, Oil and NGL Reserves

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

Proved natural gas and oil reserves are those quantities of natural gas and oil 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. 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 natural gas or oil 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 Cawley, Gillespie and Associates, Inc. (CG&A) of Fort Worth, Texas, prepared the Company's natural gas, oil and NGL reserves estimates as of September 30, 2022, and the independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, prepared the Company's natural gas, oil and NGL reserves estimates as of September 30, 2021 and 2020.

The Company's net proved natural gas, oil and NGL reserves, which are located in the contiguous United States, as of September 30, 2022, 2021 and 2020, 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 the Company's Vice President of Engineering. The Vice President of Engineering, and internal staff work closely with the Independent Consulting Petroleum Engineers to ensure the integrity, accuracy and timeliness of data furnished to them for their reserves estimation process. The Company provides historical information (such as ownership interest, gas and oil production, well test data, commodity prices, operating costs, handling fees and development costs) for all properties to the Independent Consulting Petroleum Engineers. Throughout the year, the Vice President of Engineering and internal staff meet regularly with representatives of the Independent Consulting Petroleum Engineers to review properties and discuss methods and assumptions.

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 (SPE) 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, development plans and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The 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 the Company its intention to drill.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized. 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.

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 natural gas, oil and NGL reserves are summarized as follows:

	Proved Reserves			
	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Total Bcfe
September 30, 2019	80,273,906	2,380,090	1,973,280	106.4
Revisions of previous estimates	(34,666,426)	(1,094,923)	(774,214)	(45.9)
Acquisitions	972,819	156,133	84,134	2.4
Divestitures	(60,966)	(98,412)	(13,201)	(0.7)
Extensions, discoveries and other additions	1,816,144	260,555	118,480	4.1
Production	(5,962,704)	(269,786)	(168,622)	(8.6)
September 30, 2020	42,372,773	1,333,657	1,219,857	57.7
Revisions of previous estimates	21,930,522	287,961	389,825	26.0
Acquisitions	7,814,545	91,198	41,085	8.6
Divestitures	(820,122)	(11,622)	(4,174)	(0.9)
Extensions, discoveries and other additions	354,670	28,125	26,748	0.7
Production	(6,699,720)	(224,479)	(171,488)	(9.1)
September 30, 2021	64,952,668	1,504,840	1,501,853	83.0
Revisions of previous estimates	2,405,959	(13,498)	409,597	4.8
Acquisitions	15,302,364	29,987	18,260	15.6
Divestitures	(16,624,066)	(72,244)	(83,931)	(17.6)
Extensions, discoveries and other additions	3,627,989	132,227	82,024	4.9
Production	(7,427,708)	(198,535)	(165,120)	(9.6)
September 30, 2022	62,237,206	1,382,777	1,762,683	81.1

The prices used to calculate reserves and future cash flows from reserves for natural gas, oil and NGL, respectively, were as follows: September 30, 2022 - \$6.41, \$90.33, \$38.09; September 30, 2021 - \$2.79/Mcf, \$56.51/Bbl, \$20.58/Bbl; September 30, 2020 - \$1.62/Mcf, \$40.18/Bbl, \$9.95/Bbl.

The changes in reserves at September 30,2022, as compared to September 30, 2021, are attributable to:

Revisions of previous estimates from 2021 to 2022 that were primarily the result of

- Positive pricing revisions of 8.1 Bcfe of proved developed revisions due to natural gas and oil wells extending their economic limits later than was projected in 2021 due to higher commodity prices.

- Negative performance revisions of 3.3 Bcfe (comprised of all proved developed), principally due to steep declines following workovers on high working interest Woodford Shale wells in the Arkoma Stack play in Oklahoma and steeper declines on Bossier Shale wells drilled in the last two years as compared to Haynesville Shale wells in the Haynesville play of Texas.

Acquisitions and divestitures were the result of

- The sale of 17.6 Bcfe proved developed, consisting predominately of working interest properties in the Fayetteville Shale play in Arkansas, and the Arkoma Stack play and Western Anadarko Basin in Oklahoma.

- The acquisition of 15.6 Bcfe, predominately of royalty interest properties in the active drilling programs of the Haynesville Shale play in east Texas and western Louisiana and the Mississippi and Woodford Shale intervals in the SCOOP play in the Ardmore basin of Oklahoma, of which 7.0 Bcfe were proved developed and 8.6 Bcfe were proved undeveloped.

Extensions, discoveries and other additions from 2021 to 2022 that are principally attributable to

- Reserve extensions, discoveries and other additions of 4.9 Bcfe (comprised of 1.7 Bcfe proved developed and 3.2 Bcfe proved undeveloped reserves) principally resulting from:

    a) The Company's royalty interest ownership in the ongoing development of unconventional natural gas, utilizing horizontal drilling, in the Haynesville Shale play of East Texas and Western Louisiana.

    b) The Company's royalty interest ownership in the ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma.

And production of 9.6 Bcfe from the Company's natural gas and oil properties.

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)
September 30, 2020	40,924,083	1,148,989	1,135,864	1,448,690	184,668	83,993
September 30, 2021	60,287,881	1,439,860	1,467,092	4,664,787	64,980	34,761
September 30, 2022	50,304,185	1,275,853	1,698,046	11,933,021	106,924	64,637

The following details the changes in proved undeveloped reserves for 2022 (Mcfe):

Beginning proved undeveloped reserves	5,263,233
Proved undeveloped reserves transferred to proved developed	(4,132,227)
Revisions	63,036
Extensions and discoveries	3,164,434
Sales	-
Purchases	8,603,911
Ending proved undeveloped reserves	12,962,387

During fiscal year 2022, total net PUD reserves increased by 7.7 Bcfe. In fiscal year 2022, a total of 4.1 Bcfe (79% of the beginning balance) was transferred to proved developed. The remaining balance of approximately 11.8 Bcfe (225% of the beginning balance) of positive revisions to PUD reserves consist of acquisitions of 8.6 Bcfe in the Haynesville Shale in Texas and Louisiana and Meramec and Woodford SCOOP play in Oklahoma and additions and extensions of 3.2 Bcfe within the active drilling program areas of (i) the Haynesville Shale in Texas and Louisiana, (ii) the SCOOP Meramec and Woodford in Oklahoma, (iii) the STACK Meramec and Woodford in Oklahoma and (iii) the Bakken in North Dakota.

The Company anticipates that all 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, the Company intends to remove the reserves associated with those locations from proved reserves as revisions.

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 natural gas, oil and NGL 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 the Company's 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.

	2022	2021	2020
Future cash inflows	$ 591,082,414	$ 297,138,886	$ 134,179,216
Future production costs	(131,377,260)	(115,681,617)	(66,136,222)
Future development and asset retirement costs	(2,543,510)	(1,873,126)	(1,957,225)
Future income tax expense	(107,209,614)	(40,697,140)	(13,224,535)
Future net cash flows	349,952,030	138,887,003	52,861,234
10% annual discount	(167,382,649)	(64,096,661)	(21,727,081)
Standardized measure of discounted future net cash flows	$ 182,569,381	$ 74,790,342	$ 31,134,153

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

	2022	2021	2020
Beginning of year	$ 74,790,342	$ 31,134,153	$ 85,561,529
Changes resulting from:			
Sales of natural gas, oil and NGL, net of production costs	(56,691,954)	(25,812,485)	(12,692,681)
Net change in sales prices and production costs	172,990,983	43,951,090	(46,499,344)
Net change in future development and asset retirement costs	(360,323)	49,542	(20,571)
Extensions and discoveries	14,493,340	803,714	2,841,807
Revisions of quantity estimates	14,569,169	33,482,964	(28,332,653)
Acquisitions (divestitures) of reserves-in-place	(5,808,769)	9,041,028	1,169,819
Accretion of discount	9,652,434	3,893,028	11,039,792
Net change in income taxes	(33,623,250)	(13,937,867)	17,037,980
Change in timing and other, net	(7,442,591)	(7,814,825)	1,028,475
Net change	107,779,039	43,656,189	(54,427,376)
End of year	$ 182,569,381	$ 74,790,342	$ 31,134,153

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 Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company’s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognizes 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. Based on their evaluation, the Company’s Chief Executive Officer and Chief Financial Officer have concluded that the Company’s disclosure controls and procedures were effective as of September 30, 2022.

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

The Company’s management is responsible for establishing and maintaining adequate “internal control over financial reporting,” as such term is defined in Exchange Act Rule 13a-15(f). The Company’s internal control structure is designed to provide reasonable assurance to its management and Board regarding the reliability of financial reporting and the preparation and fair presentation of its financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles.

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 management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the Company’s internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on their evaluation, the Company’s Chief Executive Officer and Chief Financial Officer have concluded that the Company’s disclosure controls over financial reporting were effective as of September 30, 2022.

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, 2022, presented preceding the Company’s financial statements included in this Form 10-K. Additionally, the financial statements included in this Annual Report on Form 10-K, have also been audited by the Company’s independent registered public accounting firm, whose report is presented preceding 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, 2022, or subsequent to the date the assessment was completed through the filing of this Form 10-K.

ITEM 9B OTHER INFORMATION

Third Amendment to Credit Agreement

On December 7, 2022, the Company entered into a Third Amendment (the “Third Amendment”) to the Credit Agreement. Pursuant to the terms of the Third Amendment, among other changes, (a) the borrowing base under the Credit Facility was reaffirmed at $50 million, which constitutes the periodic redetermination of the borrowing base for December 1, 2022 and is not deemed an unscheduled redetermination, (b) the required title percentage owed by the Company was decreased from 80% to 50% and (c) the required mortgage percentage owed by the Company was decreased from 80% to 75%.

The above description of the material terms and conditions of the Third Amendment does not purport to be complete and is qualified in its entirety by reference to the full text of the Third Amendment, which is filed as Exhibit 10.8 to this Annual Report on Form 10-K.

Change in Fiscal Year and Amendment of Bylaws

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In order to reflect the change in fiscal year, the Company's Board has adopted an amendment to the Company's Bylaws, effective December 9, 2022. Section 7.08 of the Company's Bylaws has been amended to provide that the fiscal year of the Company shall consist of twelve (12) calendar months terminating on December 31st of each calendar year, rather than terminating on September 30th of each calendar year. Further, Section 7.08 of the Company's Bylaws has been amended to provide that the Board may further change the fiscal year of the Company, without amending the Bylaws, by resolution adopted by a majority of the whole Board at any special or regular meeting of the Board.

A copy of the Amended and Restated Bylaws of the Company is filed as Exhibit 3.2 to this Annual Report on Form 10-K.

Termination of a Material Definitive Contract

On December 12, 2022, the Company voluntarily terminated its At-The-Market Equity Offering Sales Agreement, dated August 25, 2021, as amended by Amendment No. 1 dated May 10, 2022 (the "ATM Agreement"), that was entered into with Stifel. Pursuant to the ATM Agreement, the Company was authorized to offer and sell, from time to time, through or to Stifel, up to 3,000,000 shares of Common Stock. During the term of the ATM Agreement, 1,531,013 shares of Common Stock were sold pursuant to the ATM Agreement for proceeds of approximately $5.9 million, net of commissions paid. The ATM Agreement was terminable at will by the Company at any time without penalty.

ITEM 9C DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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 Director Independence and Item 14 – Principal Accountant Fees and Services), is incorporated by reference from the Company's definitive proxy statement, which will be filed with the SEC within 120 days after the end of the fiscal year to which this Annual 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

(1.1)	At-The-Market Equity Offering Sales Agreement by and between PHX Minerals Inc. and Stifel, Nicolaus & Company, Incorporated, dated August 25, 2021 (incorporated by reference to Exhibit 1.1 to Form 8-K filed with the SEC on August 25, 2021)
(1.2)	Amendment No. 1 to At-The-Market Equity Offering Sales Agreement, dated May 10, 2022, by and between PHX Minerals Inc. and Stifel, Nicolaus & Company, Incorporated (incorporated by reference to Exhibit 1.1 to Form 8-K filed with the SEC May 10, 2022).
(2.1)	Agreement and Plan of Merger, dated as of March 31, 2022, by and between PHX Minerals Inc., an Oklahoma corporation, and PHX Minerals (DE) Inc., a Delaware corporation (incorporated by reference to Exhibit 2.1 to Form 8-K12B filed with the SEC on April 5, 2022).
(3.1)	Certificate of Incorporation of PHX Minerals Inc., as amended (incorporated by reference to Exhibit 3.1 to Form 8-K12B filed with the SEC on April 5, 2022).
(3.2)	Amended and Restated Bylaws of PHX Minerals Inc.
(4.1)	Description of Capital Stock of PHX Minerals Inc. (incorporated by reference to Exhibit 99.1 to Form 8-K12B filed April 5, 2022).
*(10.1)	Amended Indemnification Agreement indemnifying directors and officers (incorporated by reference to Exhibit 10 to Form 8-K filed with the SEC on June 19, 2007)
*(10.2)	Form of Amended and Restated Change-in-Control Executive Severance Agreement (incorporated by reference to Exhibit 10.17 to Form 10-K filed with the SEC on December 10, 2020)
*(10.3)	PHX Minerals Inc. Amended 2010 Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Form 10-K filed with the SEC on December 10, 2020)
*(10.4)	PHX Minerals Inc. 2021 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on March 8, 2021)
(10.5)	Credit Agreement dated as of September 1, 2021, among PHX Minerals Inc., each lender from time to time party thereto, and Independent Bank, as Administrative Agent and L/C Issuer (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on September 3, 2021)
(10.6)	First Amendment to Credit Agreement dated as of December 6, 2021, by and among PHX Minerals Inc., each lender party thereto, and Independent Bank, as Administrative Agent and L/C Issuer (incorporated by reference to Exhibit 10.3 to Form 8-K filed with the SEC on December 9, 2021).
(10.7)	Second Amendment to Credit Agreement dated as of May 18, 2022, by and among PHX Minerals Inc., each lender party thereto, and Independent Bank, as Administrative Agent and L/C Issuer (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 19, 2022).
(10.8)	Third Amendment to Credit Agreement dated as of December 7, 2022, by and among PHX Minerals Inc., each lender party thereto, and Independent Bank, as Administrative Agent and L/C Issuer.
+(10.9)	Purchase and Sale Agreement, dated November 10, 2021, by and between PHX Minerals Inc., as Buyer, and Vendera Resources III, LP and Vendera Management III LLC, collectively as Seller (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on November 12, 2021).
+(10.10)	Purchase and Sale Agreement, dated December 6, 2021, by and among Merrimac Properties Partners, LLC and Quarter Horse Energy Partners, LLC, as Sellers, and PHX Minerals Inc., as Buyer (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on December 9, 2021).
+(10.11)	Purchase and Sale Agreement, dated December 6, 2021, by and between Palmetto Investment Partners II, LLC, as Seller, and PHX Minerals Inc., as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed with the SEC on December 9, 2021).
(23.1)	Consent of Ernst & Young, LLP
(23.2)	Consent of Cawley, Gillespie and Associates, Inc., Independent Petroleum Engineering Consultants
(23.3)	Consent of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(24.1)	Power of Attorney (see signature page)
(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
(99.1)	Report of Cawley, Gillespie and Associates, Inc., Independent Petroleum Engineering Consultants
(101.INS)	Inline XBRL Instance Document
(101.SCH)	Inline XBRL Taxonomy Extension Schema Document
(101.CAL)	Inline XBRL Taxonomy Extension Calculation Linkbase Document
(101.LAB)	Inline XBRL Taxonomy Extension Labels Linkbase Document
(101.PRE)	Inline XBRL Taxonomy Extension Presentation Linkbase Document
(101.DEF)	Inline XBRL Taxonomy Extension Definition Linkbase Document
(104)	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*	Indicates management contract or compensatory plan or arrangement
+	The Purchase and Sale Agreement contains schedules and exhibits that have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The Company agrees to furnish a supplemental copy of any such omitted exhibit or schedule to the SEC upon request.

ITEM 16 FORM 10-K SUMMARY

None.

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.

PHX MINERALS INC.

By: /s/ Chad L. Stephens
Chad L. Stephens
President and Chief Executive Officer

Date: December 13, 2022

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Chad L. Stephens and Ralph D'Amico, with full power of substitution and re-substitution, his or her true and lawful attorney-in-fact and agent, to sign any amendments to this report, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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 Chad L. Stephens	President and Chief Executive Officer (principal executive officer)	December 13, 2022
/s/Ralph D'Amico Ralph D'Amico	Vice President and Chief Financial Officer (principal financial officer)	December 13, 2022
/s/Chad D. True Chad D. True	Vice President of Accounting (principal accounting officer)	December 13, 2022
/s/ Mark T. Behrman Mark T. Behrman	Non-Executive Chairman of the Board	December 13, 2022
/s/ Glen A. Brown Glen A. Brown	Director	December 13, 2022
/s/ Lee M. Canaan Lee M. Canaan	Director	December 13, 2022
/s/ Peter B. Delaney Peter B. Delaney	Director	December 13, 2022
/s/ Steven L. Packebush Steven L. Packebush	Director	December 13, 2022
/s/ John H. Pinkerton John H. Pinkerton	Director	December 13, 2022

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PHX Shareholders Letter Continued...

Since January 2020, we have spent a total of $100 million acquiring minerals in our two core focus areas - $48 million of this in fiscal 2022 and an additional $14 million year to date fiscal 2023 (as of October 1, 2022). This has allowed us to triple our total 3P reserves since 2020 from approximately 57 BCFE to approximately 190 BCFE (YE 2022).

Our Fiscal Year 2022 financial results really highlight our transformation. Year-over-year, our corporate volumes were up a modest 6% as we divested of the non-operating assets. However, our royalty volumes were up 49% and company royalty reserves up 45% (all royalty reserves), as a result of newly drilled and completed wells associated with our active mineral acquisition programs commenced production. Our operating cash flow and adjusted EBITDA were up YOY by approximately 65% positively impacted by the dramatic increase in commodity prices and our higher margin royalty volume growth. Our Return on Capital Employed exceeded 20% in the 2022 fiscal year.

We have been able to achieve this solid growth while focusing on a strong balance sheet and maintaining a debt/EBITDA ratio of around 1.0x. This will allow the company to weather the uncertain landscape depicted in my introductory comments, while taking advantage of the energy macro trends.

We believe natural gas is the bridge fuel to transition the world to a cleaner environment. We are well positioned to take advantage of this with our strategy, core focus areas and financial strength, which will drive shareholder value.

I would like to extend my appreciation to all our employees and partners for their hard work in helping us achieve our excellent results in 2022. I also extend my thanks to our dedicated Board of Directors for their support and wisdom in guiding us to this point. We are well positioned to continue our success in 2023 and beyond.

Chad L. Stephens

Chad L. Stephens
CEO and President

PHX MINERALS

Corporate Headquarters

1320 S. University Dr., Suite 720
Fort Worth, TX 76107

Internet Address

Company financial information, public disclosures and other information are available through PHX's website at:
www.phxmin.com

Stock Exchange

New York Stock Exchange
Symbol: PHX

Independent Registered Public Accounting Firm

Ernst & Young LLP
Oklahoma City, Oklahoma

Stock Transfer & Dividend Paying Agent

Standard U.S. postal mail:
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078

Overnight/express delivery:
Computershare Trust Company, N.A.
150 Royall St., Suite 101
Canton, MA 02021

Toll free within U.S. and Canada
1-800-884-4225

Outside U.S. and Canada
1-781-575-2879

Website: www.computershare.com

Email inquiry address for investors:
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