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

FORM 10-K

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

For the fiscal year ended December 31, 2023
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: 001-39464

HighPeak Energy, Inc.

(Exact name of Registrant as specified in its charter)

Delaware	**84-3533602**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

421 W. 3rd St., Suite 1000
Fort Worth, Texas 76102
(Address of principal executive offices and zip code)

(817) 850-9200
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	HPK	The Nasdaq Stock Market LLC
Warrants to purchase Common Stock	HPKEW	The Nasdaq Stock Market LLC

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. 762(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

As of June 30, 2023, the aggregate market value of the common stock of the Registrant held by non-affiliates was $244,881,644 based on the closing price as reported on the Nasdaq Global Market of $10.88.

Number of shares of common stock outstanding as of February 29, 2024 – 128,420,923.

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the Definitive Proxy Statement for the Company's Annual Meeting of Stockholders to be held in June 2024, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2023, are incorporated into Part III of this Annual Report on Form 10-K.

HIGHPEAK ENERGY, INC.
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HIGHPEAK ENERGY, INC.

Definitions of Certain Terms and Conventions Used Herein

Within this Annual Report on Form 10-K (this "Annual Report"), the following terms and conventions have specific meanings:

- ***"10.000% Senior Notes***" means the $225.0 million aggregate principal amount of our 10.000% Senior Notes due 2024, which were issued pursuant to an indenture in February 2022 and repaid in full in September 2023.
- ***"10.625% Senior Notes***" means the $250.0 million aggregate principal amount of our 10.625% Senior Notes due 2024, $225.0 million of which were issued pursuant to an indenture in November 2022 and $25.0 million of which were issued pursuant to an indenture in December 2022 and repaid in full in September 2023.
- ***"3-D seismic"*** means three-dimensional seismic data which is geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two-dimensional data.
- ***"ASC"*** means Accounting Standards Codification.
- ***"ASU"*** means Accounting Standards Update.
- ***"Basin"*** means a large natural depression on the earth's surface in which sediments generally brought by water accumulate.
- ***"Bbl"*** means a standard barrel containing 42 United States gallons.
- ***"Bcf"*** means one billion cubic feet.
- ***"Boe"*** means a barrel of crude oil equivalent and is a standard convention used to express crude oil and natural gas volumes on a comparable crude oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of six thousand cubic feet of natural gas to one Bbl of crude oil or NGL.
- ***"Boepd"*** means Boe per day.
- ***"Bopd"*** means one barrel of crude oil per day.
- ***"Btu"*** means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

- ***"Collateral Agency Agreement*"** means the Company's Collateral Agency Agreement, dated as of September 12, 2023, by and among HighPeak Energy, Inc., Texas Capital Bank, as collateral agent, Chambers Energy Management, LP, as term representative, Mercuria Energy Trading SA, as first-out representative prior to giving effect to that certain Collateral Agency Joinder – Additional First-Out Debt, dated as of November 1, 2023, and Fifth Third Bank, National Association as first-out representative after giving effect to that certain Collateral Agency Joinder – Additional First-Out Debt, dated as of November 1, 2023.
- ***"common stock"*** or ***"HighPeak Energy common stock"*** means the Company's common stock, par value $0.0001 per share.
- ***"Completion"*** The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- ***"Credit Agreement*"** means the Term Loan Credit Agreement and the Senior Credit Facility Agreement.
- ***"DD&A"*** means depletion, depreciation and amortization.
- ***"Development costs"*** Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas. For a complete definition of development costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(7).
- ***"Development project"*** A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.
- ***"Development well"*** A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
- ***"Differential"*** An adjustment to the price of crude oil, NGL or natural gas from an established spot market price to reflect differences in the quality and/or location of crude oil, NGL or natural gas.
- ***"Dry hole"*** or ***"dry well"*** A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
- ***"Economically producible"*** The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.
- ***"EUR"*** or ***"Estimated ultimate recovery"*** The sum of reserves remaining as of a given date and cumulative production as of that date.
- ***"Exploratory well"*** An exploratory well is a well drilled to find a new field, to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well as those items are defined by the SEC.
- ***"Extension well"*** An extension well is a well drilled to extend the limits of a known reservoir.
- ***"FASB"*** 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 differs from nearby rocks.
- ***"GAAP"*** means accounting principles generally accepted in the United States of America.
- ***"Gross wells"*** means the total wells in which a working interest is owned.
- ***"Held by production"*** Acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of crude oil or natural gas.
- ***"HH"*** means Henry Hub, a distribution hub in Louisiana that serves as the delivery location for natural gas futures contracts on the NYMEX.

- ***"HighPeak Energy"*** or the ***"Company"*** means HighPeak Energy, Inc. and its subsidiaries.
- ***"HighPeak I"*** means HighPeak Energy, LP, a Delaware limited partnership.
- ***"HighPeak II"*** means HighPeak Energy II, LP, a Delaware limited partnership.
- ***"Horizontal drilling"*** A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.
- ***"HighPeak Contributors"*** means HighPeak I, HighPeak II and HPK GP.
- ***"HPK GP"*** means HighPeak Energy, LLC, a Delaware limited liability company.
- ***"Hydraulic fracturing"*** is the technique of stimulating the production of hydrocarbons from tight formations. The Company routinely utilizes hydraulic fracturing techniques in its drilling and completion programs. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.
- ***"Lease operating expenses"*** The expenses of lifting crude oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, marketing and transportation costs, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.
- ***"MBbl"*** means one thousand Bbls.
- ***"MBoe"*** means one thousand Boes.
- ***"Mcf"*** means one thousand cubic feet and is a measure of natural gas volume.
- ***"MMBbl"*** means one million Bbls.
- ***"MMBtu"*** means one million Btus.
- ***"MMcf"*** means one million cubic feet and is a measure of natural gas volume.
- ***"Net acres"*** The percentage of total acres an owner has out of a particular number of gross acres or a specified tract. As an example. an owner who has 50% interest in 100 gross acres owns 50 net acres.
- ***"Net production"*** Production that is owned by us, less royalties and production due others.
- ***"NGL"*** means natural gas liquids, which are the heavier hydrocarbon liquids that are separated from the natural gas stream; such liquids include ethane, propane, isobutane, normal butane and gasoline.
- ***"NYMEX"*** means the New York Mercantile Exchange.
- ***"OPEC"*** means the Organization of Petroleum Exporting Countries.
- ***"Operator"*** The individual or company responsible for the exploration and/or production of a crude oil or natural gas well or lease.
- ***"Plugging"*** A downhole tool that is set inside the casing to isolate the lower part of the wellbore.
- ***"Pooling"*** The bringing together of small tracts or fractional mineral interests in one or more tracts to form a drilling and production unit for a well under applicable spacing rules.
- ***"Principal Stockholder Group***" means HighPeak Pure Acquisition, LLC, a Delaware limited liability company, and wholly owned subsidiary of HighPeak I, the HPK Contributors and Jack Hightower and each of their respective affiliates and certain permitted transferees, collectively.
- ***"Prior Credit Agreement"*** means the Company's Credit Agreement, dated as of December 17, 2020, as amended from time to time, among HighPeak Energy, Inc., as Borrower, Wells Fargo Bank, National Association, as administrative agent, and the Lenders party thereto.
- ***"Production costs"*** Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).
- ***"Productive well"*** A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
- ***"Proration unit"*** A unit that can be effectively and efficiently drained by one well, as allocated by a governmental agency having regulatory jurisdiction.
- ***"Prospect"*** A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
- ***"Proved developed nonproducing reserves"*** or ***"PDNP"*** means proved reserves that are developed nonproducing reserves.
- ***"Proved developed producing reserves"*** or ***"PDP"*** means proved reserves that are developed producing reserves.
- ***"Proved developed reserves"*** means proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and can be expected to be recovered through extraction technology installed and operational at the time of the reserve estimate and can be subdivided into PDP and PDNP reserves.

- ***"Proved reserves"*** Those quantities of crude oil and natural gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
  (i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil or natural gas on the basis of available geoscience and engineering data.
  (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.
  (iii) Where direct observation from well penetrations has defined a highest known crude oil elevation and the potential exists for an associated natural gas cap, proved crude oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.
  (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.
  (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average 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.
- ***"Proved undeveloped reserves"*** or ***"PUD"*** means proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion. Undrilled locations can be classified as having PUDs only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five (5) years, unless specific circumstances justify a longer time.
- ***"PV-10"*** When used with respect to crude oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property related expenses, discounted to a present value using an annual discount rate of 10%. PV-10 is not a financial measure calculated in accordance with GAAP and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.
- ***"Realized price"*** The cash market price less all expected quality, transportation and demand adjustments.
- ***"Recompletion"*** The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs or enhancing existing reservoirs in an attempt to establish or increase existing production.
- ***"Reserves"*** Reserves are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering crude oil and natural gas or related substances to market, and all permits and financing required to implement the project.
- ***"Reservoir"*** A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
- ***"Resources"*** Quantities of crude oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.
- ***"royalty"*** An interest in a crude oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof) but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.
- ***"SEC"*** means the United States Securities and Exchange Commission.

- ***"Senior Credit Facility Agreement*"** means the Company's Credit Agreement, dated as of November 1, 2023, among HighPeak Energy, Inc., as Borrower, Fifth Third Bank, National Association, as administrative agent and collateral agent, and the lenders party thereto.
- ***"Service well"*** A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include natural gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.
- ***"Spacing"*** The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 100-acre spacing, the distance between horizontal wellbores, e.g., 880-foot spacing or the number of wells per section, e.g., 6-well spacing. It is often established by regulatory agencies and/or the operator to optimize recovery of hydrocarbons.
- ***"Spot market price"*** The cash market price without reduction for expected quality, transportation and demand adjustments.
- ***"Standardized measure"*** The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines as well as the rules and regulations of the SEC, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to DD&A. Standardized measure does not give effect to derivative transactions.
- ***"Stratigraphic test well"*** A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.
- ***"Term Loan Credit Agreement*"** means the Company's Credit Agreement, dated as of September 12, 2023, by and between HighPeak Energy, Inc., as Borrower, Texas Capital Bank, as administrative agent, Chambers Energy Management, LP, as collateral agent, and the lenders from time-to-time party thereto.
- ***"Undeveloped acreage"*** Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether such acreage contains proved reserves.
- ***"Unit"*** The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
- ***"U.S."*** means the United States.
- ***"warrants"*** means warrants to purchase one share of HighPeak Energy common stock at a price of $11.50 per share.
- ***"Wellbore"*** The hole drilled by the bit that is equipped for crude oil and natural gas production on a completed well. Also called well or borehole.
- ***"Working interest"*** The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.
- ***"Workover"*** Operations on a producing well to restore or increase production.
- ***"WTI"*** means West Texas Intermediate, a light sweet blend of crude oil produced from fields in western Texas and is a grade of crude oil used as a benchmark in crude oil pricing.
- With respect to information on the working interest in wells and acreage, ***"net"*** wells and acres are determined by multiplying ***"gross"*** wells and acres by the Company's working interest in such wells or acres. Unless otherwise specified, wells and acreage statistics quoted herein represent gross wells or acres.
- All currency amounts are expressed in U.S. dollars.

The terms "development costs," "development project," "development well," "economically producible," "estimated ultimate recovery," "exploratory well," "production costs," "reserves," "reservoir," "resources," "service wells" and "stratigraphic test well" are defined by the SEC. Except as noted, the terms defined in this section are not the same as SEC definitions.

Cautionary Statement Concerning Forward-Looking Statements

This Annual Report 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"). All statements other than statements of historical facts included or incorporated by reference in this Annual Report, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected revenues, projected costs, and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on the beliefs of management, as well as assumptions made by, and information currently available to, the Company's management. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "believes," "plans," "expects," "anticipates," "forecasts," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate" or the negative of such terms and similar expressions as they relate to the Company are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different from the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the Company's assumptions about:

- our ability to refinance or pay, when due, the principal of, interest or other amounts due in respect of our indebtedness;
- our liquidity, cash flow and access to capital;
- the supply and demand for and market prices of crude oil, NGL, natural gas and other products or services, and the associated impact of our hedging policies relating thereto;
- capital expenditures and other contractual obligations, including our obligations under the Term Loan Credit Agreement and Senior Credit Facility Agreement;
- the results of our ongoing strategic alternatives review process;
- political instability or armed conflict in crude oil or natural gas producing regions, such as the ongoing war between Russia and Ukraine and the Israel-Hamas conflict;
- volatility in the political, legal and regulatory environments ahead of the upcoming U.S. presidential election;
- the integration of acquisitions;
- the availability of capital resources;
- production and reserve levels;
- drilling and completion risks;
- inflation rates and the impacts of associated monetary policy responses, including increased interest rates and resulting pressures on economic growth;
- economic and competitive conditions;
- the impacts of revising our drilling plan during the year transitioning to an increased or decreased rig count from time to time;
- weather conditions;
- epidemics or pandemics, including the effects of related public health concerns and the impact of continued actions taken by governmental authorities and other third parties in response to pandemics and their impact on commodity prices, supply and demand considerations, and storage capacity;
- the availability of goods and services and supply chain issues;
- legislative, regulatory or policy changes;
- regulatory and related policy actions intended by federal, state and/or local governments to reduce fossil fuel use and associated carbon emissions, to drive the substitution of renewable forms of energy for crude oil and natural gas, which may over time reduce demand for crude oil, NGL and natural gas, including as a result of the Inflation Reduction Act of 2022 ("IRA 2022") or otherwise;
- our ability to predict and manage the effects of actions of OPEC and agreements to set and maintain production levels, including as a result of recent production cuts by OPEC;
- cyber-attacks;
- occurrence of property acquisitions or divestitures;
- the securities or capital markets and our ability to access such markets on attractive terms or at all, and related risks such as general credit, liquidity, market and interest-rate risks; and

- other factors disclosed under “Part I, Items 1 and 2. Business and Properties”, “Part I, Item 1A. Risk Factors”, “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Part II, Item 7A. Quantitative and Qualitative Disclosures about Market Risk” and elsewhere in this Annual Report.

All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, the Company assumes no duty to update or revise its forward-looking statements based on changes in internal estimates or expectations or otherwise.

Additionally, we caution you that reserve engineering is a process of estimating underground accumulations of crude oil, NGL and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of crude oil, NGL and natural gas that are ultimately recovered.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

HighPeak Energy, Inc., a Delaware corporation formed on October 29, 2019, is an independent crude oil and natural gas exploration and production company that explores for, develops and produces crude oil, NGL and natural gas in the Permian Basin in West Texas, more specifically, the Midland Basin primarily in Howard and Borden Counties, Texas, and to a lesser extent Scurry and Mitchell Counties, which lie within the northeastern part of the crude oil-rich Midland Basin. Our acreage is composed of two core areas, Flat Top primarily in the northern portion of Howard County extending into southern Borden County, southwest Scurry County and northwest Mitchell County and Signal Peak in the southern portion of Howard County.

HighPeak Energy focuses on the Midland Basin and specifically the Howard and Borden Counties area of the Midland Basin. Over the last eight decades the Howard and Borden Counties area of the Midland Basin was partially developed with vertical wells using conventional methods, and during the last decade has experienced significant redevelopment activity in the Lower Spraberry and Wolfcamp A formations utilizing modern horizontal drilling technology, with some operators having additional success developing the Middle Spraberry, Jo Mill, Wolfcamp B and Wolfcamp D formations, through the use of modern, high-intensity hydraulic fracturing techniques, decreased frac spacing, increased proppant usage and increased lateral lengths. Our interpretation of available IHS Markit data as well as our own drilling and completion results show that Howard and Borden Counties have a high crude oil mix percentage.

The Company's assets include certain rights, title and interests in crude oil and natural gas assets located primarily in Howard and Borden Counties, Texas, and to a lesser extent, Scurry and Mitchell Counties, Texas. As of December 31, 2023, the Company's assets consisted of two generally contiguous leasehold positions of approximately 143,187 gross (131,636 net) acres covering various subsurface depths, approximately 64% of which were held by production, with an average working interest of approximately 92%. We operate approximately 98% of the net acreage across the Company's assets. HighPeak Energy's horizontal development drilling plan is currently focused on the Wolfcamp A and Lower Spraberry formations. We utilize multi-well pad development to lower drilling and completion cycle times and create infrastructure and facility economies of scale to reduce overall costs, optimize and maximize crude oil and natural gas recoveries, return on investment and value creation.

Available Information

The mailing address of HighPeak Energy's principal executive office is 421 W. 3rd Street, Suite 1000, Fort Worth, Texas 76102. HighPeak Energy's telephone number is (817) 850-9200. As of December 31, 2023, HighPeak Energy had forty-eight full-time employees.

HighPeak Energy files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The SEC maintains a website (*www.sec.gov*) that contains reports, proxy and information statements, and other information regarding issuers, including HighPeak Energy, that file electronically with the SEC.

The Company makes available free of charge through its website (*www.highpeakenergy.com*) its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC. In addition to the reports filed or furnished with the SEC, HighPeak Energy publicly discloses information from time to time in its press releases and investor presentations that are posted on its website or publicly during accessible investor conferences. Such information, including information posted on or connected to the Company's website, is not a part of, or incorporated by reference in, this Annual Report or any other document the Company files with or furnishes to the SEC.

HighPeak Energy's common stock and warrants are listed on the Nasdaq Global Market ("Nasdaq") under the symbols "HPK" and "HPKEW," respectively.

Properties

The Company's assets are located in the northeastern part of the Midland Basin. The majority of the acreage position is located across the eastern half of Howard and Borden Counties recently extending into far southwestern Scurry County and far northwestern Mitchell County in two largely contiguous acreage blocks, the northern position of which is referred to as the Flat Top area and the southern position of which is referred to as the Signal Peak area. The Midland Basin is part of the Permian Basin of West Texas and Eastern

New Mexico. The Permian Basin covers an area of about 96,000 square miles and is comprised of five (5) sub-regions including the Midland Basin, the Central Basin Platform, the Delaware Basin, the Northwest Shelf and the Eastern Shelf. The Central Basin Platform ("CBP") is a central uplift, with the Delaware Basin located to the west of the CBP, and the Midland Basin located to the east of the CBP. The bulk of the Permian Basin's increase in crude oil production since 2007 has come from several target zones including the Spraberry and Wolfcamp formations. The Permian Basin has produced billions of barrels of equivalent crude oil and natural gas and is estimated by the United States Geologic Survey to contain significant remaining hydrocarbon potential.

HighPeak Energy developed its properties using up to six (6) drilling rigs and four (4) frac crews during the year ended December 31, 2023, ending the year using three (3) drilling rigs and one (1) frac crew. The Company expects to average two (2) drilling rigs and one (1) frac crew during 2024 under our current development plan. HighPeak Energy expects to fund its forecasted capital expenditures with cash on its balance sheet and cash generated by operations.

HighPeak Energy has the discretion to modify its capital program. Because HighPeak Energy operates a high percentage of its acreage, capital expenditure amounts and timing are largely discretionary and within its control. HighPeak Energy determines its capital expenditures depending on a variety of factors, including, but not limited to, the success of its drilling activities, prevailing and anticipated prices for crude oil and natural gas, the availability of necessary equipment, infrastructure and capital, limitations on expenditures under certain leverage scenarios pursuant to the Term Loan Credit Agreement, the receipt and timing of required regulatory permits and approvals, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows. Additionally, if HighPeak Energy curtails or reallocates priorities in its drilling program, HighPeak Energy may lose a portion of its acreage through lease expirations. However, in the event of any such curtailment or reallocation of priorities, HighPeak Energy would expect to prioritize lease retention to minimize any expirations. Please see "Risk Factors—Risks Related to Our Business—Crude oil, NGL and natural gas prices are volatile. Sustained periods of low, or declines in, crude oil, NGL and natural gas prices could adversely affect HighPeak Energy's business, financial condition and results of operations and its ability to meet its capital expenditure obligations and other financial commitments," "Risk Factors—Risks Related to Our Business —HighPeak Energy's development projects and acquisitions will require substantial capital expenditures. HighPeak Energy may be unable to obtain required capital or financing on satisfactory terms, including as a result of recent increases in cost of capital resulting from Federal Reserve policies or otherwise, which could reduce its ability to access or increase production and reserves" and "Risk Factors—Risks Related to Our Business—Certain of the undeveloped leasehold acreage of HighPeak Energy's assets is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed."

Reserve Summary

The estimated proved reserves of the Company's assets as of December 31, 2023, 2022 and 2021 were prepared by Cawley, Gillespie and Associates, Inc. ("CG&A"). As of December 31, 2023, 2022 and 2021, the Company's assets contained 154,162, 122,958 and 64,213 MBoe, respectively, of estimated proved reserves. In addition, as of December 31, 2023, 2022 and 2021, the estimated proved reserves of the Company's assets were estimated by CG&A to be 91%, 92% and 92% crude oil and NGL, respectively, and 9%, 8% and 8% natural gas, respectively. The following table provides summary information regarding the estimated proved reserves data of the Company's assets based on the 2023 Reserve Report, 2022 Reserve Report and 2021 Reserve Report (each defined below) as of December 31, 2023, 2022 and 2021, respectively:

As of Date	Proved Total (MBoe)(1)	% Crude Oil & NGL	% Developed
December 31, 2023	154,162	91%	52%
December 31, 2022	122,958	92%	50%
December 31, 2021	64,213	92%	45%

(1) The estimated net proved reserves were determined using the unweighted arithmetic average first-day-of-the month prices for the prior twelve (12) months in accordance with guidelines established by the SEC. As of December 31, 2023, 2022 and 2021, for crude oil and NGL volumes, this average WTI spot price of $78.22, $93.67 and $66.56 per barrel, respectively, was adjusted for quality, transportation and a regional price differential. As of December 31, 2023, 2022 and 2021, for natural gas volumes, the average HH spot price of $2.637, $6.358 and $3.598 per MMBtu, respectively, was adjusted for energy content, gathering, transportation and processing fees and a regional price differential. All prices are held constant throughout the lives of the properties. As of December 31, 2023, 2022 and 2021, the average adjusted prices realized over the remaining lives of the Company's assets by CG&A were $78.13, $94.59 and $66.10 per barrel of crude oil, $17.33, $36.69 and $29.76 per barrel of NGL and $0.198, $4.871 and $0.786 per Mcf of natural gas, respectively.

Reserve Data

Preparation of Reserve Estimates

The reserve estimates as of December 31, 2023, 2022 and 2021 included in this Annual Report are based on evaluations prepared by CG&A in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC (individually, the "2023 Reserve Report," the "2022 Reserve Report" and the "2021 Reserve Report" and, collectively the "Reserve Reports"). CG&A was selected for their historical experience and geographic expertise in engineering similar resources. The summary information pertaining to reserve estimates as of December 31, 2023, 2022 and 2021, respectively, of HighPeak Energy, prepared by CG&A, were led by W. Todd Brooker. Mr. Brooker is a Licensed Professional Engineer in the State of Texas and has been practicing at CG&A for 31 years and, including such 31 years, has over 33 years of total industry experience. Copies of the Reserve Reports are attached to this Annual Report as Exhibits 99.1, 99.2 and 99.3, respectively.

Proved reserves are those quantities of crude oil, NGL 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. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to EUR with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease. The technical and economic data used in the estimation of the proved reserves include, but are not limited to, well logs, geologic maps, well-test data, production data (including flow rates), well data (including lateral lengths), historical price and cost information, and property ownership interests. CG&A uses this technical data, together with standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy. The proved developed reserves and EURs per well are estimated using performance analysis, analogs and volumetric analysis. The estimates of the proved developed reserves and EURs for each developed well are used to estimate the proved undeveloped reserves for each proved undeveloped location (utilizing type curves, statistical analysis, and analogy).

Internal Controls

The internal staffs of petroleum engineers and geoscience professionals at HighPeak Energy work closely with their independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to their independent reserve engineers in the preparation of their reserve report. Periodically, HighPeak Energy's technical teams meet with the independent reserve engineers to review properties and discuss methods and assumptions used to prepare reserve estimates for the Company's assets.

Reserve engineering is a subjective process of estimating volumes of economically recoverable crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, estimates of economically recoverable crude oil, NGL and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices, future production rates and costs. Please read the section entitled "Risk Factors" appearing elsewhere in this Annual Report.

The reserve estimates as of December 31, 2023, 2022 and 2021, respectively, were prepared by geologists and reservoir engineers who integrate geological, geophysical, engineering and economic data to produce high quality reserve estimates and economic forecasts. The process was supervised by Christopher Mundy, Vice President, Reserves and Evaluations, for HighPeak Energy, who has approximately 27 years of experience in crude oil and natural gas operations, reservoir engineering and management, reserves management, unconventional and conventional reservoir characterization and strategic planning.

The reserve estimation process and the reserve estimates of the Company's assets as of December 31, 2023, 2022 and 2021, respectively, were reviewed and approved by our technical staff, other members of senior management and our Chief Executive Officer. The Reserve Reports prepared by CG&A contain further discussion of the reserve estimates and the procedures used in connection with its preparation.

The reserve estimates as of December 31, 2023, 2022 and 2021, included in this Annual Report are based on evaluations prepared by the independent petroleum engineering firm CG&A representing 100% of the Company's assets' total net proved reserves in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. The Independent Reserve Engineers were selected for their historical experience and geographic expertise in engineering similar resources.

Estimated Proved Reserves

The following tables present the estimated net proved crude oil and natural gas reserves as of December 31, 2023, 2022 and 2021, based on the Reserve Reports of the Company's assets as of such date.

	Proved Reserve Volumes				
	Crude Oil (MBbls)	**NGL (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)**	**%**
As of December 31, 2023:					
Developed	58,631	12,183	52,671	79,593	52%
Undeveloped	60,923	7,913	34,400	74,569	48%
Total proved reserves	119,554	20,096	87,071	154,162	100%
As of December 31, 2022:					
Developed	47,845	7,968	32,669	61,258	50%
Undeveloped	50,971	6,401	25,969	61,700	50%
Total proved reserves	98,816	14,369	58,638	122,958	100%
As of December 31, 2021:					
Developed	22,610	3,540	14,611	28,585	45%
Undeveloped	29,215	3,838	15,450	35,628	55%
Total proved reserves	51,825	7,378	30,061	64,213	100%

Development of Proved Undeveloped Reserves

The following table summarizes the changes in HighPeak Energy's proved undeveloped reserves for the years ended December 31, 2021, 2022 and 2023:

	Total (MBoe)
Proved undeveloped reserves at December 31, 2020	12,233
Extensions and discoveries	26,806
Sales of minerals-in-place	(184)
Conversions into proved developed reserves	(3,186)
Revisions	(41)
Proved undeveloped reserves at December 31, 2021	35,628
Extensions and discoveries	37,394
Purchases of minerals-in-place	7,302
Conversions into proved developed reserves	(15,446)
Revisions	(3,178)
Proved undeveloped reserves at December 31, 2022	61,700
Extensions and discoveries	42,440
Conversions into proved developed reserves	(25,955)
Sales of minerals-in-place	(1,387)
Revisions	(2,229)
Proved undeveloped reserves at December 31, 2023	74,569

As of December 31, 2023, HighPeak Energy's assets contained approximately 74,569 MBoe of proved undeveloped reserves, consisting of 60,923 MBbl of crude oil, 7,913 MBbl of NGL and 34,400 MMcf of natural gas. As of December 31, 2022, HighPeak Energy's assets contained approximately 61,700 MBoe of proved undeveloped reserves, consisting of 50,971 MBbl of crude oil, 6,401 MBbl of NGL and 25,969 MMcf of natural gas. As of December 31, 2021, HighPeak Energy's assets contained approximately 35,628 MBoe of proved undeveloped reserves, consisting of 29,215 MBbl of crude oil, 3,838 MBbl of NGL and 15,450 MMcf of natural gas. Proved undeveloped reserves will be converted from undeveloped to developed as we drill and complete each location and the wells begin production.

Proved undeveloped reserves changed during the year ended December 31, 2023 primarily as a result of the following significant factors:

- Extensions and discoveries of 42,440 MBoe related to new proved undeveloped locations added as a result of HighPeak Energy's drilling activities;
- Conversions into proved developed reserves of 25,955 MBoe related to locations that were successfully drilled and completed during the year ended December 31, 2023;
- Sales of minerals-in-place of undeveloped reserves of 1,387 MBoe related to a farm out to another operator in return for a carried interest during the year ended December 31, 2023; and
- Downward revisions of 2,229 MBoe including downward adjustments of approximately 1,748 MBoe related to forecasts, approximately 445 MBoe primarily attributable to a decrease in crude oil, NGL and natural gas prices and approximately 36 MBoe primarily related to increased forecasted operating expenses.

Proved undeveloped reserves changed during the year ended December 31, 2022 primarily as a result of the following significant factors:

- Extensions and discoveries of 37,394 MBoe related to new proved undeveloped locations added as a result of HighPeak Energy's drilling activities;
- Purchases of minerals-in-place of 7,302 MBoe related to the acquisition of undeveloped drilling locations included;
- Conversions into proved developed reserves of 15,446 MBoe related to locations that were successfully drilled and completed during the year ended December 31, 2022; and
- Downward revisions of 3,178 MBoe including downward adjustments of approximately 3,636 MBoe related to forecasts and approximately 38 MBoe primarily related to increased forecasted operating expenses, partially offset by an increase of approximately 496 MBoe attributable to an increase in crude oil, NGL and natural gas prices.

Proved undeveloped reserves changed during the year ended December 31, 2021 primarily as a result of the following significant factors:

- Extensions and discoveries of 26,806 MBoe related to new proved undeveloped locations added as a result of HighPeak Energy's drilling activities;
- Sales of minerals-in-place of 184 MBoe related to the divestiture of non-operated non-core undeveloped drilling locations to a third-party operator;
- Conversions into proved developed reserves of 3,186 MBoe related to locations that were successfully drilled and completed during the year ended December 31, 2021; and
- Downward revisions of 41 MBoe including downward adjustments of approximately 350 MBoe related to forecasts and approximately 32 MBoe primarily related to increased forecasted operating expenses, partially offset by an increase of approximately 341 MBoe attributable to an increase in crude oil, NGL and natural gas prices.

Historically, the Company invested a significant amount of its capital budget to drill unproved locations rather than convert proved undeveloped reserves to proved developed reserves. However, in the years ended December 31, 2023 and 2022, $481.5 million and $391.3 million, respectively, of development capital expenditures were incurred primarily to convert proved undeveloped reserves to proved developed reserves, compared with $45.9 million in development capital expenditures in the year ended December 31, 2021. Also, a portion of the Company's development capital expenditures each year was for the continued development of a water infrastructure system and the drilling of salt-water disposal wells to facilitate the Company's increased levels of produced water, reduce its future water sourcing costs by recycling produced water and reduce the use of trucking for its produced water disposal activities as well as the continued construction of central tank batteries for handling of the Company's increasing production volumes.

As of December 31, 2023, all our proved undeveloped reserves are scheduled to be developed within five years from the date they were initially recorded.

PV-10

PV-10 is a non-GAAP financial measure and differs from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. We refer to PV-10 as the present value of estimated future net cash flows of estimated proved reserves using a discount rate of 10%. This amount includes projected revenues, estimated production costs, estimated future development costs and estimated cash flows related to future asset retirement obligations.

Unlike PV-10, the standardized measure deducts future U.S. federal income taxes and Texas margin taxes and abandonment obligations on wells with no proved reserves as of December 31, 2023, 2022 and 2021, respectively. Neither PV-10 nor standardized measure represents an estimate of the fair market value of the applicable crude oil and natural gas properties. It is industry standard to use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

The following tables present the undiscounted estimated future net cash flows, PV-10 and standardized measure of the proved reserves of the Company at December 31, 2023, 2022 and 2021 (in thousands):

As of December 31, 2023	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net cash flows	$ 3,205,041	$ 2,072,541	$ 5,277,582
Present value of estimated future net cash flows	$ 2,061,301	$ 822,766	$ 2,884,067
Present value of future income taxes/abandonment costs			(276,363)
Standardized measure			$ 2,607,704

As of December 31, 2022	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net cash flows	$ 3,729,169	$ 3,160,098	$ 6,889,267
Present value of estimated future net cash flows	$ 2,319,958	$ 1,552,087	$ 3,872,045
Present value of future income taxes/abandonment costs			(455,537)
Standardized measure			$ 3,416,508

As of December 31, 2021	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net cash flows	$ 1,178,041	$ 1,236,250	$ 2,414,291
Present value of estimated future net cash flows	$ 742,037	$ 596,156	$ 1,338,193
Present value of future income taxes/abandonment costs			(219,384)
Standardized measure			$ 1,118,809

Estimated future net cash flows represents the estimated future revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using pricing differentials and costs under existing economic conditions as of December 31, 2023, 2022 and 2021, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, in accordance with SEC guidelines, CG&A uses the unweighted arithmetic average of the prices on the first day of each month in the 12-month period ended December 31, 2023, 2022 and 2021. These prices were $78.22, $93.67 and $66.56 per Bbl for crude oil and NGL and $2.637, $6.358 and $3.598 per MMBtu for natural gas, respectively, before adjustment for energy content, gathering, transportation and processing fees and basis differential adjustments. The average adjusted prices realized over the remaining lives of the Company's assets by CG&A were $78.13, $94.59 and $66.10 per barrel of crude oil, $17.33, $36.69 and $29.76 per barrel of NGL and $0.198, $4.871 and $0.786 per Mcf of natural gas as of December 31, 2023, 2022 and 2021, respectively. These prices should not be interpreted as a prediction of future prices. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to DD&A.

Production, Revenue and Price History

For a description of historical production, revenues, average sales prices and unit costs of the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations."

The following tables summarize the average net sales volumes, average unhedged sales prices by product and production costs of the Company for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31, 2023								
	Crude Oil		NGL		Natural Gas		Total		
	Sales Volumes (MBbl)	Average Sales Price ($/Bbl)	Sales Volumes (MBbl)	Average Sales Price ($/Bbl)	Sales Volumes (MMcf)	Average Sales Price ($/Mcf)	Sales Volumes (MBoe)	Average Sales Price ($/Boe)	Production Costs ($/Boe)
	13,885	$ 78.26	1,547	$ 21.51	7,219	$ 1.56	16,635	$ 66.80	$ 8.74
Average net daily sales volumes (Boepd)							45,577		

	Year Ended December 31, 2022								
	Crude Oil		NGL		Natural Gas		Total		
	Sales Volumes (MBbl)	Average Sales Price ($/Bbl)	Sales Volumes (MBbl)	Average Sales Price ($/Bbl)	Sales Volumes (MMcf)	Average Sales Price ($/Mcf)	Sales Volumes (MBoe)	Average Sales Price ($/Boe)	Production Costs ($/Boe)
	7,562	$ 94.61	821	$ 35.67	3,323	$ 5.36	8,937	$ 84.56	$ 7.79
Average net daily sales volumes (Boepd)							24,485		

	Year Ended December 31, 2021								
	Crude Oil		NGL		Natural Gas		Total		
	Sales Volumes (MBbl)	Average Sales Price ($/Bbl)	Sales Volumes (MBbl)	Average Sales Price ($/Bbl)	Sales Volumes (MMcf)	Average Sales Price ($/Mcf)	Sales Volumes (MBoe)	Average Sales Price ($/Boe)	Production Costs ($/Boe)
	3,002	$ 70.10	224	$ 35.11	1,020	$ 3.88	3,396	$ 64.82	$ 7.38
Average net daily sales volumes (Boepd)							9,304		

Productive Wells

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and crude oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which HighPeak Energy holds an interest, and net wells are the sum of the fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which HighPeak Energy holds a working interest as of December 31, 2023.

	Crude Oil			Natural Gas		
	Gross	Net	Average Working Interest	Gross	Net	Average Working Interest
Horizontal:						
Operated	273	260.7	95%	—	—	n/a
Non-operated	18	1.2	7%	—	—	n/a
Vertical:						
Operated	158	157.0	99%	8	8.0	100%
Non-operated	5	2.0	40%	—	—	n/a
Total:						
Operated	431	417.7	97%	8	8.0	100%
Non-operated	23	3.2	14%	—	—	n/a

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which HighPeak Energy holds an interest as of December 31, 2023. Approximately 64% of the net acreage of HighPeak Energy was held by production as of December 31, 2023.

Developed Acres(1)(4)		Undeveloped Acres(4)		Total Acres	
Gross Acres(2)	Net Acres(3)	Gross Acres(2)	Net Acres(3)	Gross Acres(2)	Net Acres(3)
86,198	81,813	56,989	49,823	143,187	131,636

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.

(2) A gross acre is an acre in which HighPeak Energy holds a working interest. The number of gross acres is the total number of acres in which HighPeak Energy holds a working interest.

(3) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.
(4) Minor amounts of our developed and undeveloped acres do not cover all formation depths in underlying acreage.

Undeveloped Acreage Expirations

The following table sets forth the number of total net undeveloped acres as of December 31, 2023 across HighPeak Energy's properties that will expire in 2024, 2025, 2026, 2027, 2028 and thereafter, unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed.

2024	27,424
2025	18,201
2026	1,664
2027	30
2028	—
Thereafter	320
	47,639

With respect to the 27,424 net acres expiring in 2024 across our properties, HighPeak Energy intends to retain substantially all 27,424 net acres through initiating completion operations of existing wells and the drilling of new wells, with the remaining net acreage being retained either through lease renewals or extensions. HighPeak Energy intends to retain substantially all of its undeveloped acreage through its development plan. Please see "Item 1A. Risk Factors – Risks Related to Our Business – Certain of the undeveloped leasehold acreage of HighPeak Energy's assets is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed."

Drilling Activities

The following table describes new development and exploratory/extension wells drilled within the Company's assets during the years ended December 31, 2023, 2022 and 2021. The information should not be indicative of future performance, nor should it be assumed there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. As of December 31, 2023 and not included in the following table, were 10 gross (9.1 net) wells in the process of being drilled and 18 gross (13.4 net) wells either waiting on completion or in various stages of completion operations. In addition, the Company had three (3) gross (3.0 net) salt-water disposal wells in final stages of completion. As of December 31, 2023, HighPeak Energy was running a three-rig program. The Company expects to average two (2) drilling rigs and one (1) frac crew during 2024 under our current development plan. Our development program may change based on capital availability and other factors.

	Year Ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	57	49.5	28	23.4	5	5.0
Dry	—	—	—	—	—	—
Exploratory/Extension wells:						
Productive	70	63.3	64	54.8	25	19.5
Dry	—	—	—	—	—	—
Service wells:						
Salt-Water Disposal	3	3.0	4	4.0	1	1.0

Delivery Commitments

Beginning October 2021, the Company has a minimum volume commitment under its crude oil marketing agreement in its Flat Top area whereby it must deliver minimum gross volumes to its central tank battery facilities of 5,000 Bopd for the first year, 7,500 Bopd for the second year and 10,000 Bopd for the remaining eight years of the contract. However, the Company has the ability under the contract to cumulatively bank excess volumes delivered to offset future minimum volume commitments. For the period from October 1, 2021 to December 31, 2023, the Company had delivered approximately 29,600 Bopd under the contract, banking excess volumes at the outset. Given the current production levels coupled with the wells planned to come on production in 2024 and beyond, the Company expects to meet the volume commitments under this agreement well in advance of the requirement. There are no material commitments to deliver a fixed and determinable quantity of natural gas production from the Company's assets to customers under existing contracts.

Operations

General

As of December 31, 2023, HighPeak Energy's properties consisted of 143,187 gross (131,636 net) acres with an average working interest of approximately 92%.

Facilities

Production facilities related to HighPeak Energy's properties are located near the producing wells and consist of salt-water disposal wells and related facilities, a salt-water disposal pipeline systems throughout Flat Top and Signal Peak, storage tanks, two-phase and/or three-phase separation equipment, flowlines, metering equipment and safety systems. Predominant artificial lift methods include electrical submersible pumps, rod pumps and some plunger lifts. HighPeak Energy's mostly contiguous acreage position allows for optimized capital expenditures for production facilities and associated water handling infrastructure.

Our properties are well serviced by existing crude oil, natural gas and water infrastructure and gathering systems. Currently, the majority of our crude oil production in Flat Top is transported by pipeline while the majority of our crude oil in Signal Peak is transported by truck. The Company used a competitive bidding process that resulted in attractive terms relative to market indices. The natural gas production from our properties is gathered by third-party processors with the majority of the natural gas production currently processed to extract NGL. The extracted liquids and residue natural gas are sold to various intrastate and interstate markets on a competitive pricing basis.

Marketing and Customers

The following table sets forth the percentage of revenues attributable to customers who have accounted for 10% or more of revenues attributable to the Company's assets during the years ended December 31, 2023, 2022 and 2021.

	Years Ended December 31,		
Major Customers	**2023**	**2022**	**2021**
DK Trading & Supply, LLC ("Delek")	82%	88%	94%
Energy Transfer Crude Marketing, LLC ("ETC")	14%	*	*

* Less than 10%.

No other purchaser accounted for 10% or more of revenue attributable to the Company's assets on a combined basis in the years ended December 31, 2023, 2022 or 2021. The loss of any such purchaser could adversely affect revenues attributable to the Company's assets in the short term. Please see "Risk Factors—Risks Related to Our Business—HighPeak Energy depends upon a small number of significant purchasers for the sale of most of its crude oil, NGL and natural gas production. The loss of one or more of such purchasers could, among other factors, limit HighPeak Energy's access to suitable markets for the crude oil, NGL and natural gas it produces."

For crude oil sales, HighPeak Energy currently is party to a ten-year contract with Delek, with production from Flat Top being mostly piped sales through a crude oil gathering system. Currently, the majority of our crude oil sales from Signal Peak are being trucked. The Flat Top crude oil contract is at known and published indices with a fixed primary term and an evergreen option thereafter. The contract contains a minimum volume commitment that commenced on October 1, 2021 based on the gross barrels delivered at the Company's central tank battery facilities and is 5,000 Bopd for the first year, 7,500 Bopd for the second year and 10,000 Bopd for the remaining eight years of the contract. However, the Company has the ability under the contract to cumulatively bank excess volumes delivered to offset future minimum volume commitments. For the period from October 1, 2021 to December 31, 2023, the Company has delivered approximately 29,600 Bopd under the contract. The remaining monetary commitment as of December 31, 2023, if the Company never delivers any additional volumes under the agreement, is approximately $7.8 million. In addition, HighPeak Energy sells its natural gas production from the Company's assets to multiple third-party purchasers pursuant to the terms of natural gas processing and purchase contracts at varying rates. The natural gas production is gathered and processed under agreements with a primary term and generally an evergreen extension option.

Competition

The crude oil and natural gas industry is intensely competitive, and HighPeak Energy competes with other companies that have greater resources. Many of these companies not only explore for and produce crude oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive crude oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than HighPeak Energy's financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low crude oil and natural gas market prices. HighPeak Energy's larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than HighPeak Energy can, which could adversely affect HighPeak Energy's competitive position, as applicable. HighPeak Energy's ability to acquire additional properties and to discover reserves in the future will be dependent upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because HighPeak Energy will have fewer financial and human resources than many companies in their industry, HighPeak Energy may be at a disadvantage in bidding for exploratory prospects and producing crude oil and natural gas properties.

There is also competition between crude oil and natural gas producers and other industries producing energy and fuel. For example, HighPeak Energy also faces indirect competition from alternative energy sources, including wind and solar. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which HighPeak Energy operates, including recently passed legislation such as the IRA 2022. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon HighPeak Energy's future operations as related to the Company's assets. Such laws and regulations may substantially increase the costs of developing crude oil and natural gas and may prevent or delay the commencement or continuation of a given operation. HighPeak Energy's larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than HighPeak Energy can, which would adversely affect HighPeak Energy's competitive positions, as applicable. See "Item 1A. Risk Factors—Risks Related to Our Business—Competition in the crude oil and natural gas industry is intense, which will make it more difficult for HighPeak Energy to acquire properties, market crude oil or natural gas and secure trained personnel."

Seasonality of Business

Weather conditions can affect the demand for, and prices of, crude oil and natural gas. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher prices while the demand for crude oil is typically higher during the second and third quarters. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Title to Properties

As is customary in the crude oil and natural gas industry, HighPeak Energy, as operator of the Company's assets, initially conducts (at minimum) a cursory review of the title to properties in connection with acquisition of leasehold acreage. HighPeak Energy has also obtained title opinion coverage on a majority of the Company's assets and has performed customary reviews of the title to substantially all of the Company's assets. Additionally, at such time as HighPeak Energy determines to conduct drilling operations on those properties, HighPeak Energy will conduct a thorough title examination, will obtain division order title opinions, and will perform curative work with respect to any significant defects that may exist prior to: (i) commencement of drilling operations; and (ii) the initial disbursement of associated revenues. HighPeak Energy has obtained title opinions on substantially all its producing properties. The crude oil and natural gas properties within the Company's assets are subject to customary royalty and other interests, liens for current taxes and other burdens which HighPeak Energy believes does not materially interfere with the use of, or affect the carrying value of, the properties.

Prior to completing an acquisition of producing crude oil and natural gas properties, HighPeak Energy may perform title reviews on the most significant leases and may obtain a title opinion, obtain an updated title opinion or review previously obtained title opinions.

HighPeak Energy believes it has satisfactory title to all the material properties within the Company's assets in accordance with standards generally accepted in the crude oil and natural gas industry. Although title to the Company's assets is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the crude oil and natural gas industry, none of these liens, restrictions, easements, burdens or encumbrances will likely materially detract from the value of the properties within the Company's assets or from HighPeak Energy's interests in these properties or materially interfere with HighPeak Energy's use of these properties in the operation of their business. In addition, HighPeak Energy believes they have obtained sufficient rights-of-way grants and permits from public authorities and private parties for them to operate their business in all material respects as described in this Annual Report.

Crude Oil and Natural Gas Leases

The typical crude oil and natural gas lease agreement covering the properties within the Company's assets provides for the payment of royalties to the mineral owner for all crude oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on the properties within the Company's assets are approximately 25%.

Regulation of the Crude Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the crude oil and natural gas industry are regularly considered by Congress, the states, Federal Energy Regulatory Commission ("FERC"), the U.S. Environmental Protection Agency ("EPA"), the Department of Transportation ("DOT"), other federal agencies and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

In addition, unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Crude Oil and Natural Gas

Crude oil and natural gas production and related operations are substantially affected by federal, state and local laws and regulations. In particular, crude oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All the jurisdictions in which the Company's assets are located have statutory provisions regulating the development and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Crude oil and natural gas operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Such laws and regulations are frequently amended or reinterpreted. Therefore, it is not possible to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the crude oil and natural gas industry are regularly considered by Congress, the states, FERC, the EPA, the DOT, other federal agencies and the courts. It is not possible to predict when or whether any such proposals may become effective.

Federal, state and local statutes and regulations require permits for drilling, salt-water disposal and pipeline operations, drilling bonds and reports concerning operations. The Company's assets are located in Texas, which regulates drilling and operating activities by, among other things, requiring permits for the drilling of wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells.

The laws of Texas also govern a number of conservation matters, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum allowable rates of production from crude oil and natural gas wells, the regulation of well spacing or density and plugging and abandonment of wells. The effect of these regulations is to limit the amount of crude oil and natural gas that the wells within the Company's assets can produce and to limit the number of wells or the locations that can be drilled within the Company's assets, although operators can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, various states impose a production or severance tax with respect to the production and sale of crude oil, NGL and natural gas within their jurisdiction. Failure to comply with these rules and regulations can result in substantial penalties.

Regulation Affecting Sales and Transportation of Commodities

Sales prices of crude oil, NGL and natural gas are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate crude oil and natural gas, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of crude oil and natural gas may be subject to certain state and potentially federal reporting requirements.

The price and terms of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of crude oil and natural gas produced, as well as the revenues received from sales of such production. Gathering systems may be subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, crude oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for crude oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further, state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

In addition to the regulation of natural gas pipeline transportation, the FERC has jurisdiction over the purchase or sale of natural gas or the purchase or sale of transportation services subject to the FERC's jurisdiction pursuant to the Energy Policy Act of 2005. Under this law, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to the FERC's jurisdiction under the Natural Gas Act of 1938 to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud, to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading or to engage in any act or practice that operates as a fraud or deceit upon any person. The Energy Policy Act of 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 up to $1,544,521 per day per violation (adjusted annually based on inflation). The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to the FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize or contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 is intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and service conditions for interstate transportation of liquids, including crude oil and NGL, under the Interstate Commerce Act (the "ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

Rates of interstate liquids pipelines are currently regulated by the FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. In December 2020, the FERC concluded its five-year index review to establish the new inflationary adjustment for the five-year period commencing July 1, 2021, for liquid pipeline rates subject to indexing. In this review, the FERC considered changes to pipeline industry costs, including, among other things, the effects of the legislation known as the Tax Cuts and Jobs Act of 2017. The FERC issued an order on

December 17, 2020 establishing an inflationary adjustment of Producer Price Index for Finished Goods ("PPI-FG") plus 0.78% (PPI-FG+0.78%) for the five-year period commencing July 1, 2021 (the "December 2020 Order"). Numerous requests for rehearing were filed. On May 14, 2021, the FERC published the oil pricing index factor utilizing the inflationary adjustment factor established in the December 2020 Order, resulting in a negative percentage change of approximately 0.58% for the index year July 1, 2021 through June 30, 2022. On January 20, 2022, the FERC issued an order on rehearing in which it modified the methodology used to calculate the inflationary adjustment resulting in a revised inflationary adjustment for the five-year period commencing July 1, 2021, of PPI-FG minus 0.21% (PPI-FG-0.21%) (the "Rehearing Order"). As a result of the Rehearing Order, the index factor for the July 1, 2021 through June 30, 2022 index year now provides for a negative percentage change of approximately 1.6%. The FERC directed all oil pipelines to ensure their rates were consistent with the revised index factor effective March 1, 2022. Following the Rehearing Order, some parties sought rehearing with the FERC while others filed petitions for review with the Fifth Circuit and D.C. Circuit. On May 6, 2022, the FERC issued its order denying the rehearing requests. Additional petitions for review were filed with the D.C. Circuit after the May 6th order and the challenges have been consolidated at the D.C. Circuit. The appeal remains pending before the D.C. Circuit.

Under the FERC's regulations, a liquids pipeline can request the authority to charge market-based rates for transportation service if it satisfies certain criteria, and also can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity. Therefore, requests for service by new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to the FERC's regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1,472,546 per violation per day (adjusted annually based on inflation). In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement its new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1,450,040 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Crude oil and natural gas development operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas; require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The regulatory burden on the crude oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, emission or discharge limits or waste handling, disposal or remediation obligations could increase the cost to our operators of developing our properties. Moreover, accidental releases or spills may occur in the course of operations on our properties, causing our operators to incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which operations related to the Company's assets may be subject.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered responsible for the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and persons that disposed or arranged for the disposal or the transportation for disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The failure of an operator other than the Company to comply with applicable environmental regulations may, in certain circumstances, be attributed to the Company.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular crude oil and natural gas development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the costs to manage and dispose of generated wastes. In addition, in the course of operating the Company's assets, it is possible that some amounts of ordinary industrial wastes will be generated, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

The Company's assets consist of numerous properties that have been used for crude oil and natural gas development and production activities for many years. Hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from properties within the Company's assets, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of the properties within the Company's assets have been operated by third-parties or by previous owners or operators who have treated and disposed of hazardous substances, wastes or petroleum hydrocarbons. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to undertake responsive or corrective measures with respect to the Company's assets, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges, Fluid Disposal and NORM

The Water Pollution Control Act, also known as the Clean Water Act ("CWA") and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other crude oil and natural gas wastes, into or near navigable waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the "Corps"). The scope of jurisdiction under the CWA has been subject to several rulemakings by the EPA in recent years and is subject to ongoing litigation. Most recently, following legal action on a January 2023 final rule which established a definition of "waters of the United States" based on the broader pre-2015 definition, the U.S. Supreme Court's decision in *Sackett v. EPA*, and the enactment of a subsequent September 2023 rule is enjoined subject to litigation, and the EPA and Corps are implementing the definition of "waters of the United States" consistent with the pre-2015 regulatory regime and the changes made by the *Sackett* decision, which utilizes the "continuous surface connection" test to determine if wetlands qualify as waters of the United States. In the remaining 23 states, the agencies are implementing the September 2023 rule, which amended the January 2023 rule to incorporate the *Sackett* decision. However, the September 2023 rule does not define the term "continuous surface connection," and it is currently unclear how broadly the September 2023 rule and the *Sackett* decision will be interpreted by the agencies. Therefore, the future reach of the CWA is uncertain at this time. To the extent any rule further expands the scope of the CWA's jurisdiction, the Company could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The timeliness associated with obtaining permits also has the potential to delay the development of crude oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of crude oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, the Company may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of crude oil.

The primary federal law related specifically to crude oil spill liability is the Oil Pollution Act ("OPA"), which amends and augments the crude oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of crude oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain crude oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of a crude oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for crude oil removal costs and a variety of public and private damages. Although defenses exist, they are limited.

Fluids resulting from crude oil and natural gas production, consisting primarily of salt-water, are disposed by injection in belowground disposal wells regulated under the Underground Injection Control ("UIC") program and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and may restrict the types and quantities of fluids that may be disposed. In addition, state and federal regulatory agencies have focused on a possible connection between crude oil and natural gas activity and induced seismicity.

For example, in 2015, the United States Geological Study identified eight states, including Texas, with areas of induced seismicity that could be attributed to fluid injection or crude oil and natural gas extraction.

In response to these concerns, some states, including Texas, have imposed additional requirements for the permitting of produced water disposal wells, such as volume and pressure limitations or seismicity thresholds for temporary cessations of activity. In September 2021, the Texas Railroad Commission ("TRRC") issued a notice to operators in the city of Midland area to reduce daily injection volumes following multiple earthquakes above 3.5 magnitude over an 18-month period. The notice also required disposal well operators to provide injection data to TRRC staff to further analyze seismicity in the area. Subsequently, the TRRC ordered the indefinite suspension of all deep produced water injection wells in the area, effective December 31, 2021. The response area has since been expanded following an additional earthquake in December 2022 to cover an additional 17 wells. Other seismic response areas have also been established, including the Northern Culberson-Reeves Seismic Response Area, where 23 deep disposal well permits were suspended in December 2023. While the ultimate outcome of these actions is uncertain, the adoption and implementation of any new laws or regulations that restrict our operators' ability to use hydraulic fracturing or dispose of produced water gathered from drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring them to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

In addition, naturally occurring radioactive material ("NORM") is brought to the surface in connection with crude oil and natural gas production. Comprehensive federal regulation does not currently exist for NORM; however, the EPA has studied the impacts of technologically enhanced NORM, and several states, including Texas, regulate the disposal of NORM. Concerns have arisen over traditional NORM disposal practices (including discharge through publicly owned treatment works into surface waters), which may increase the costs associated with management of NORM. To the extent that federal or state regulation increases the compliance costs for NORM disposal, operators may incur additional costs that may make some properties unprofitable to operate.

Air Emissions

The Clean Air Act ("CAA") and comparable state laws restrict the emission of air pollutants from many sources (e.g., compressor stations), through the imposition of air emissions standards, construction and operating permitting programs and other compliance requirements. These laws and regulations may require the Company to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard for ozone from 75 to 70 parts per billion and completed attainment/non-attainment designations in July 2018. While the EPA has determined that counties in which the Company currently operates are in attainment with the new ozone standards, these determinations may be revised in the future. Additionally, although the EPA announced in December 2020 that it intended to leave ozone NAAQS unchanged at 70 parts per billion, this decision has been subject to legal challenges, and the Biden Administration has announced plans to reconsider this standard. A final decision from the EPA remains pending. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new facilities or modify existing facilities in these newly designated non-attainment areas and result in increased expenditures for pollution control equipment, the costs of which could be significant.

In addition, the EPA has adopted new rules under the CAA that require the reduction of volatile organic compounds from certain fractured and refractured crude oil and natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In addition, the regulations place new requirements to detect and repair volatile organic compounds at certain crude oil and natural gas facilities. In May 2016, the EPA also finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the crude oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of crude oil and natural gas projects and increase the costs of development, which costs could be significant.

Regulation of Greenhouse Gas Emissions

At the federal level, no comprehensive climate change legislation has been implemented to date, though the recently-passed IRA 2022 advances numerous climate-related objectives. The EPA has, however, adopted rules under authority of the CAA that, among other things, establish prevention of significant deterioration ("PSD") construction and Title V operating permit reviews for greenhouse gases ("GHG") emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions. Under these regulations, facilities required to obtain PSD permits must meet "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operators' operations. The EPA has expanded the GHG reporting requirements to all segments of the crude oil and natural gas industry, including gathering and boosting facilities as well as completions and workovers from hydraulically fractured crude oil wells.

Federal agencies also have begun directly regulating emissions of methane from crude oil and natural gas operations. For example, in June 2016, the EPA published New Source Performance Standards, known as Subpart OOOOa, that requires certain new, modified or reconstructed facilities in the crude oil and natural gas sector to reduce these methane gas emissions. Although, in September 2020, the Trump Administration published regulations to rescind methane specific requirements and remove the transmission and storage segments from the crude oil and natural gas source category, the U.S. Congress approved, and President Biden signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions, effectively reinstating the prior standards. Additionally, in December 2023, the EPA finalized a rule that established OOOOb as more stringent new source and OOOOc as first-time existing source standards of performance for methane and VOC emissions for the crude oil and natural gas source category. Under the final rules, owners or operators of affected emission units or processes have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards under the final rule are generally the same for both new and existing sources, including enhanced leak detection using optical gas imaging and subsequent repair requirements, reduction of regulated emissions through capture and control systems, zero-emission requirements for certain equipment or processes, operations and maintenance requirements and requirements for "green well" completions. The rule also revises requirements for fugitive emissions monitoring and repair as well as equipment leaks and the frequency of monitoring surveys, establishes a "super-emitter" response program to timely mitigate emissions events as detected by governmental agencies or qualified third parties, triggering certain investigation and repair requirements, and provides additional options for the use of advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions. However, it is likely that these requirements will be subject to legal challenges. Several states have also adopted rules to control and minimize methane emissions from the production of crude oil and natural gas, and others have considered or may consider doing so in the future.

At the international level, in December 2015, the United States and 194 other participating countries adopted the Paris Agreement, which calls for each participating country to establish their own nationally determined standards for reducing carbon output. President Biden recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing again at the 26th Conference to the Parties on the UN Framework Convention on Climate Change ("COP26"), during which multiple announcements were made, including a call for parties to eliminate fossil fuel subsidies and pursue further action on non-CO2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. These goals were reaffirmed in November 2022 at the 27th Conference of the Parties to the United Nations Framework Convention on Climate Change ("COP27"), where countries were also called upon to accelerate efforts towards the phase-out of inefficient fossil fuel subsidies. The United States also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. At the 28th Conference of the Parties ("COP28"), the parties signed onto an agreement to transition away from fossil fuels in energy systems and increase renewable energy capacity, though no timeline for doing so was set. While non-binding, the agreements coming out of COP28 could result in increased pressure among financial institutions and various stakeholders to reduce or otherwise impose more stringent limitations on funding for and increase potential opposition to the production and use of fossil fuels. Although no firm commitment or timeline to phase out all fossil fuels was made at COP27 or COP28, there can be no guarantee that countries will not seek to implement such a phase-out in the future. The impacts of these actions cannot be predicted at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions for our operators, and could have a material adverse effect on our business, financial condition and results of operations. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across agencies and economic sectors. In August 2022, the IRA 2022 was signed into law, which amends the CAA to establish the first-ever federal fee on methane emissions that exceed certain thresholds from sources required to report their GHG emissions to the EPA, including certain crude oil and natural gas operations. The methane emissions charge will start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and subsequent years. The methane emissions fee could increase our operating costs. Additionally, the IRA 2022 appropriates significant federal funding for renewable energy initiatives and incentives, which could accelerate the transition away from fossil fuels and therefore reduce demand for our products and adversely affect our business and results of operations. Other actions taken by the Biden Administration, states, or local jurisdictions in the future, such as limitations or bans on products that rely on crude oil and natural gas, could also reduce demand for our products.

There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. In late 2020, the Federal Reserve announced it has joined the Network for Greening the Financial System ("NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector and, in November 2021, issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. In January 2023, the Federal Reserve issued instructions for a pilot climate scenario analysis being undertaken by six of the United States' largest banks, which is expected to conclude at the end of 2023. Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities. Ultimately, this could make it more difficult for operators to secure funding for exploration and production activities. Additionally, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or restrict more carbon-intensive activities. While we cannot predict the outcomes of such actions, they could make it more difficult for operators to engage in exploration and production activities. In addition, the SEC has proposed rules that would require registrants to report climate-related risks and business strategies, and disclose information on Scope 1 and 2 GHG emissions and, in some cases, Scope 3 emissions. The final rule remains pending and the final form and substance of these requirements is not yet known. To the extent the rules impose additional reporting obligations, we could face increased costs. Additionally, certain states have enacted or are considering similar climate-related disclosure requirements. Enhanced climate-related disclosure requirements could increase operating costs and lead to reputational or other harm with customers, regulators, or other stakeholders to the extent that our disclosures do not meet their own standards or expectations. Consequently, we are also exposed to increased litigation risks relating to alleged climate-related damages resulting from our operations, statements alleged to have been made by us or others in our industry regarding climate change risks, or in connecting with any future disclosures we may make regarding reported emissions, particularly given the inherent uncertainties and estimation required with respect to calculating and reporting GHG emissions. Finally, many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climate events that could have an adverse effect on the Company's operations. For more information, please see our risk factor titled "The operations of HighPeak Energy are subject to a variety of risks arising from climate change."

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is regularly used by operators of the Company's assets. Hydraulic fracturing is typically regulated by state crude oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has issued final regulations under the CAA establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and also finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, the TRRC has adopted a "well integrity rule," which updated the requirements for drilling, putting pipe down and cementing wells. The rule also imposes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

Certain governmental reviews are either underway or have been conducted that focus on the environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

Compliance with existing laws has not had a material adverse effect on operations related to the Company's assets, but if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where the Company's assets are located, operators could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

Endangered Species Act and Migratory Birds

The Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for crude oil and natural gas development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS was required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The agency missed the deadline but continues to review species for listing under the ESA. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"). The federal government in the past has pursued enforcement actions against crude oil and natural gas companies under the MBTA after dead migratory birds were found near reserve pits associated with drilling activities. Although the Department of Interior under the Trump Administration issued a rulemaking revoking its prior enforcement policy and concluded that an incidental take is not a violation of the MBTA, the Biden Administration has published a final rule rescinding this rulemaking, in addition to publishing an advanced notice of proposed rulemaking to codify a new definition for take that includes such incidental take as a violation of the MBTA. In any event, the identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause increased costs arising from species protection measures or could result in limitations on development activities that could have an adverse impact on the ability to develop and produce reserves within the Company's assets. For example, a review is currently pending to determine whether the dunes sagebrush lizard should be listed and, in November 2022 the FWS listed two distinct population segments of the lesser prairie-chicken under the ESA. If these species or others are listed, the FWS and similar state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species. If a portion of the Company's assets were to be designated as a critical or suitable habitat, it could adversely impact the value of the Company's assets.

Occupational Safety and Health Act

The Company will be subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. Violations can result in civil or criminal penalties as well as required abatement. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that the Company organizes and/or disclose information about hazardous materials used or produced in its operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other crude oil and natural gas activities, and require maintaining these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal or litigation, which could in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations related to the Company's assets.

Related Insurance

The Company maintains insurance against some risks associated with above or underground contamination that may occur as a result of development activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by the Company.

Human Capital

We believe that our employees are the foundation to fostering the safe operation of our assets. We foster a collaborative, inclusive and safety-minded work environment, focused on working safely every day. We seek to identify qualified internal and external talent for our organization, enabling us to execute on our strategic objectives.

As of December 31, 2023, we employed forty-eight full-time employees dedicated to operating the Company's assets. None of these employees are covered by collective bargaining agreements, and we consider our employee relations to be good.

Employee Health and Safety

Safety is important to us and begins with the protection and safety of our employees, contractors and communities where we operate. We value people above all else and remain committed to making safety and health our top priority. We continually seek to maintain and deepen our safety culture by providing a safe working environment that encourages active employee engagement, including implementing safety programs to achieve improvements in our safety culture.

The Company has taken steps to keep its employees safe during pandemics by implementing preventative measures and developing response plans intended to minimize unnecessary risk of exposure and infection among its employees. The Company has also modified certain business practices to conform to best practices encouraged by the Centers for Disease Control and Prevention, and other governmental and regulatory authorities.

Diversity and Inclusion

We are committed to fostering a work environment in which all employees treat each other with dignity and respect. This commitment extends to providing equal employment and advancement opportunities based on merit and experience. We continually strive to attract a diverse workforce by identifying potential candidates to advance and strengthen our human capital management program.

Our employee demographic profile allows us to promote inclusion of thought, skill, knowledge and culture across our operations to achieve our social obligations and commitments.

Talent Development and Retention

We value and provide opportunities for cross training and increased responsibilities, including leadership learning. These efforts allow us to recruit from within our organization for future vocational and occupational opportunities. Our management promotes formal and informal learning and development throughout the organization. We offer developmental programs focused on building the skills of our employees and to help advance employee careers, knowledge, and skillsets through training and related programs.

Legal Proceedings

The Company is not party to lawsuits related to its assets other than those arising in the ordinary course of business. Due to the nature of the crude oil and natural gas business, HighPeak Energy may, from time to time, be involved in other routine litigation or subject to disputes or claims related to the operation of the Company's assets, including workers' compensation claims and employment related disputes. In the opinion of management, none of these other pending litigation, disputes or claims against HighPeak Energy, if decided adversely, would have a material adverse effect on the Company's assets.

Offices

The principal field office for HighPeak Energy is located at 303 West Wall Street, Suite 2202, Midland, Texas 79701.

Board of Directors and Executive Officers

The following table sets forth information regarding the directors of our Board and certain executive officers:

Name	Age	Position
Jack Hightower	75	Chairman of the Board and Chief Executive Officer
Michael L. Hollis	48	President and Director
Rodney L. Woodard	68	Chief Operating Officer
Steven W. Tholen	73	Chief Financial Officer
Keith Forbes	61	Vice President and Chief Accounting Officer
Jay M. Chernosky	64	Director
Keith A. Covington	60	Director
Sharon F. Fulgham	46	Director
Larry C. Oldham	70	Director
Jason A. Edgeworth	39	Director

Jack Hightower has served as our Chairman of the Board and Chief Executive Officer ("CEO") since 2019. Prior to the HighPeak business combination (the "HighPeak business combination" or, the "business combination"), Mr. Hightower served as Chairman of the board of directors, CEO and President of Pure Acquisition Corp. ("Pure") since its incorporation in November of 2017. Mr. Hightower has over 50 years of experience in the oil and gas industry managing multiple exploration and production ("E&P") platforms. Mr. Hightower currently serves as the Chairman of the board of directors and CEO of the general partners of funds affiliated with the Company and HighPeak Energy Partners, LP and HighPeak Energy Partners II, LP (the "HighPeak Funds"), a position held since 2014. Mr. Hightower served as Chairman, President and CEO of Bluestem Energy Partners, LP ("Bluestem") from 2011 to 2013. Prior to forming Bluestem, Mr. Hightower served as Chairman, President, and CEO of Celero Energy II, LP ("Celero II") from 2006 to 2009 and as Chairman, President and CEO of Celero Energy, LP ("Celero") from 2004 to 2005. Prior to forming Celero, Mr. Hightower served as Chairman, President and CEO of Pure Resources, Inc. ("Pure Resources") (NYSE: PRS), which became the 11th largest publicly traded independent E&P company in North America. In October 2002, Unocal tendered for the Pure Resources shares it did not already own. In March 1995, Mr. Hightower founded Titan (Nasdaq: TEXP), the predecessor to Pure Resources, and served as Chairman, President and CEO. Prior to founding Titan, Mr. Hightower served as Chairman, President and CEO of Enertex Inc., the general partner and operator of record for several oil and gas partnerships from 1991 to 1994. Mr. Hightower graduated from Texas Tech University in 1970 with Bachelor of Business Administration degrees in Administrative Finance and Money, Banking & Investments.

Michael L. Hollis has served as our President and as a member of our Board since August 2020. Prior to the HighPeak business combination, Mr. Hollis served as Pure's President from December 2019 until August 2020. Prior to joining Pure, Mr. Hollis served as President and Chief Operating Officer ("COO") of Diamondback Energy, Inc. ("Diamondback") (Nasdaq: FANG), a Permian focused oil and gas producer, from January 2017 through September 2019, prior to which he served as COO since 2015 and Vice President of Drilling. Since 2011, Mr. Hollis also served on the board of directors for Diamondback as well as on the board of directors of Viper Energy Partners LP (Nasdaq: VNOM). Prior to his positions at Diamondback, Mr. Hollis was a Drilling Manager at Chesapeake Energy Corporation and also held roles of increasing responsibility in production, completions and drilling engineering at ConocoPhillips and Burlington Resources Inc. Mr. Hollis has over 20 years of oil and gas experience and graduated from Louisiana State University in 1998 with a Bachelor of Science in Chemical Engineering.

Rodney L. Woodard has served as our Chief Operating Officer since August 2020. Prior to the HighPeak business combination, Mr. Woodard served as Pure's COO and served as a director of Pure's board of directors since its inception in November 2017 and as HighPeak Energy's COO since its inception in October 2019. Mr. Woodard has over 40 years of experience in the oil and gas industry as a CEO, COO, and leader of Engineering and Operations of numerous E&P companies. Mr. Woodard has served as the Executive Vice President & COO for the HighPeak Funds from 2017 to the present. From 2016 to 2017, Mr. Woodard presented portfolio company investment proposals to acquire and develop oil and gas assets in the Permian Basin to several private equity firms. Mr. Woodard served as the President and COO of Atlantic Resources Co., LLC ("Atlantic") from 2015 to 2016. Prior to Atlantic, Mr. Woodard served as CEO and COO of Celero II, a Natural Gas Partners portfolio company, with operations principally in the Permian Basin from 2006 to 2015. Prior to Celero II, Mr. Woodard served as Executive Vice President and COO of Celero, a Quantum Energy Partners portfolio company from 2004 to 2006. From 2002 to 2004, Mr. Woodard was Vice President of Reserves and Evaluations with Pure Resources (NYSE: PRS) and was a co-founder of its predecessor, Titan Exploration (Nasdaq: TEXP). From 1986 to 1995, Mr. Woodard held various positions of increasing responsibility at Selma International Investments Ltd. From 1979 to 1986, Mr. Woodard held various positions at Delta Drilling Company, obtaining the position of Division Manager for West Texas. Mr. Woodard held various positions at Amoco Production Company from 1977 to 1979. Mr. Woodard graduated from The Pennsylvania State University in 1977 with a Bachelor of Science degree in Mechanical Engineering.

Steven W. Tholen has served as our Chief Financial Officer ("CFO") since HighPeak Energy's inception in October 2019 and is a Corporate Finance Executive with over 30 years of experience in building, leading and advising corporations through complex restructurings, purchase and sales transactions, and capital market transactions. Mr. Tholen has served as the CFO for the HighPeak Funds since 2014. Previously, Mr. Tholen served as co-founder and Executive Vice President - Finance of Fieldco Construction Services, Inc., which provided oilfield construction services to clients throughout East Texas & Western Louisiana, from 2011 to 2014. From 2009 to 2013, Mr. Tholen served as founder and President of SDL&T Energy Partners, a source of equity & debt financing to fund energy companies and energy projects worldwide. From 2001 to 2008, Mr. Tholen was Senior Vice President & CFO of Harvest Natural Resources, Inc., an E&P company with properties in the United States, Venezuela, Indonesia, Gabon, and Russia. From 1995 to 2000, Mr. Tholen served as Vice President and CFO of Penn Virginia Corporation, an independent natural gas and oil company. From 1990 to 1995, Mr. Tholen was Treasurer/Manager of Business Administration of Cabot Oil & Gas Corporation, a North American independent natural gas producer. Mr. Tholen graduated from St. John's University with a Bachelor of Science degree in Physics in 1971 and earned his Master of Business Administration in Finance from The University of Denver, Daniels School of Business in 1979.

Keith Forbes has served as our Vice President and Chief Accounting Officer ("CAO") since November 2020 and previously served as our Vice President and Controller from our inception in October 2019 until November 2020. Mr. Forbes has over 30 years of experience in various field and corporate accounting functions and business organization functions for large, geographically diverse public companies. Before his appointment as CAO to HighPeak Energy, Mr. Forbes served as Vice President and Controller of the HighPeak Funds since 2017. Mr. Forbes additionally served as Director-Business Optimization at Quicksilver Resources Inc. from December 2015 through April 2016, and as Assistant Controller-Operations and Revenue at Quicksilver Resources Inc. from June 2012 through November 2015. Mr. Forbes is a certified public accountant in Texas. Mr. Forbes graduated from Pittsburg State University with a Bachelor of Business Administrations degree in Accounting in 1985.

Jay M. Chernosky has served on our Board since August 2020 and is currently a Principal of Travis Energy Partners LP since 2019, Jayco Holdings I, LP since 2005, Jayco Holdings II, LP since 2010, Jayco Holdings LLC since 2005, Bertrand Properties LP and Bertrand Properties, Inc. since 2000, Vargas Properties LP since 2022, which are private family-owned real estate and energy investment entities. Mr. Chernosky was previously a Managing Director of the Energy & Power Corporate & Investment Banking group at Wells Fargo Securities from 2009 until his retirement in 2019. Mr. Chernosky joined Wells Fargo's predecessor firm Wachovia Securities (formerly First Union) in 1993 as a co-founder of the energy practice. Prior to joining Wells Fargo Securities, Mr. Chernosky worked in various capacities in the Energy Division of First City, Texas - Houston for 10 years. During his career, Mr. Chernosky was charged with developing strategic and financial ideas and solutions for relationships he managed for the bank and was also responsible for the origination and execution of public and private capital markets activities, including equities, bonds, convertibles, private placements, loan syndications and merger and acquisition advisory services. During this time, Mr. Chernosky's primary focus was on the upstream sector of the oil and gas industry.

Currently, Mr. Chernosky serves on the board of directors of Colt Midstream LLC, a private gas gathering and processing company focused in the Fort Worth Basin of Texas since 2019. Mr. Chernosky also serves on the regional board of directors of OneGoal Houston, a non-profit organization geared to increase the success rate of college admission and graduation for youth attending high school in low-income districts since 2012. In addition, Mr. Chernosky serves on the Endowment Board of the Christian Community Service Center since 2010.

Mr. Chernosky has previously served on the board of directors and is an active member of the Houston Producers' Forum, the Houston Energy Finance Group and the regional board of the Independent Petroleum Association of America. Mr. Chernosky graduated from The University of Texas at Austin with a Bachelor of Business Administration in 1981 and received a Master of Business Administration from the University of Houston in 1983. Mr. Chernosky is also a graduate of the Southwestern Graduate School of Banking at Southern Methodist University in 1993.

Keith A. Covington has served on our Board since August 2020 and is an active real estate investor specializing in residential properties in southern California for the past 28 years, most recently serving as a General Partner for Magnolia Partners since 2002.

Mr. Covington is an independent director on the board of directors of Gores Holdings IX, Inc. (Nasdaq: GHIX) (a Special Purpose Acquisition Company ("SPAC")), and a member of both its audit and compensation committees since its January 2022 IPO for $525 million, which will target acquisitions in any industry or sector and will have an operational focus. Mr. Covington was an independent director on the board of directors of Gores Holdings VII, Inc., a SPAC, and a member of both its audit and compensation committees since its February 2021 IPO for $550 million, which was liquidated to stockholders at par in December 2022.

Mr. Covington was a founding board member of Pure Resources, an energy company engaged in the exploration and development of oil and gas properties which had a market capitalization of over $1 billion and served such directorship from 2000 to 2002. As an independent director for over two years, Mr. Covington served as chairman of the audit committee and member of the compensation committee of Pure Resources and was a co-member of the special committee responsible for evaluating, negotiating and recommending on behalf of company shareholders the acquisition of Pure Resources to Unocal Corporation (acquired by Chevron Corporation) in October 2002.

Mr. Covington served in various capacities over 11 years at Davis Companies from 1991 to 2002, where he was Vice President and earlier served as Principal of Stone Canyon Venture Partners, LLC. Mr. Covington's tenure included responsibility in the real estate and private equity/venture capital groups within the organization. Investment and operational experience within these areas included investments in trophy commercial and mixed-use real estate assets, gaming ventures, a chain of upscale health clubs, resort properties and hotels, a restaurant and a technology company. His responsibilities included extensive independent due diligence for potential acquisitions, financial analysis and comprehensive asset management for equity investments in real estate assets and operating companies valued at over $10 billion. Prior professional experience includes Janss Corporation, a Santa Monica, CA real estate developer where he was responsible for due diligence and financial structuring and leasing of residential and commercial real estate projects from 1989 to 1990. Mr. Covington started his career as a Financial Analyst at PaineWebber Group Inc. (UBS Investment Bank) in New York with experience in real estate investment banking transactions including sale/leasebacks and the firm's largest initial public offering and real estate master limited partnership from 1985 to 1987. Mr. Covington received his Master of Business Administration from the Stanford Graduate School of Business and earned a Bachelor of Arts cum laude in Economics from Claremont McKenna College. Mr. Covington maintains a California real estate broker's license and has maintained board governance expertise through participation in KPMG's Audit Committee Institute. Mr. Covington has previously served as Chief Financial Officer for the El Segundo Senior Housing Board for over five years.

Jason A. Edgeworth has served as an Investment and Asset Manager for the John Paul DeJoria family office since 2020 with responsibility for diligence, execution and investor relations.

Previously, Mr. Edgeworth served as an Executive Director of Investment & Merchant Banking at U.S. Capital Advisors LLC from 2013 to 2020. Mr. Edgeworth's responsibilities included diligence, execution and investor communications with a focus on equity market transactions, including initial public offerings, follow on equity offerings, at-the-market equity offerings and preferred equity offerings, for public E&P companies and midstream companies. Mr. Edgeworth also advised on merchant banking and private equity transactions for the midstream and service sectors of the oil and gas industry both domestically and internationally.

From 2008 to 2012, Mr. Edgeworth served as an equity analyst at CLW Investments and Twin Eagle Resource Management and also AEW Europe and Curzon Global Partners where he focused on the energy sector and commercial and mixed-use real estate.

Mr. Edgeworth serves on or has served on the board of several companies including Borealis Alaska Oil, Inc. and Badger Midstream Energy, LP. Mr. Edgeworth graduated from the University of St. Andrews in 2008 with a Master of Arts in International Relations. Mr. Edgeworth is a Chartered Alternative Investment Analyst.

Sharon F. Fulgham has served on our Board since August 2020 and is currently a partner of the Fulgham Hampton Law Group since August 2017. Ms. Fulgham has also been associated with Carlisle Title since December 2016 and has been their corporate attorney since November 2019. Prior to working at Fulgham Law Firm, P.C., Ms. Fulgham was a partner at Kelly Hart & Hallman from January 2016 to November 2016 and an associate at Kelly Hart & Hallman from 2009 to 2016. During her legal career, Ms. Fulgham has represented numerous public and private companies in litigation matters including commercial and employment disputes. Specifically, she has extensive experience representing companies in the oil and gas sector, as well as experience in the title industry preparing title documents for real estate closings and instruction to brokers and realtors.

Over the past decade, Ms. Fulgham has served the Fort Worth community extensively through the Junior League of Fort Worth, Inc. (the "Junior League"), a charitable nonprofit organization of women committed to promoting volunteerism, developing the potential of women and improving communities, both as a community volunteer and in leadership roles within the organization. She served as Vice President of Administration and sat on the board of directors from 2015 to 2016. Ms. Fulgham is currently a sustaining member and served on the Junior League's Legal Committee from 2019 to 2022. Ms. Fulgham is also involved in the Young Men's Service League, a national nonprofit made up of mothers and their teenage sons who volunteer together to serve their local communities, and has served on the board of directors for the local chapter since 2021. Ms. Fulgham graduated cum laude from Texas Christian University with a Bachelor of Science in Biology in 2000 and went on to obtain her Juris Doctorate from the University of Houston in 2004.

Larry C. Oldham has served on our Board since August 2020 and currently serves as a Manager and Advisor of Gateway Royalty VI LLC ("Gateway VI") since 2022. Gateway VI is the sixth entity of the Gateway Royalty companies, which were founded by Chris Oldham, Mr. Oldham's son, and have been successful in acquiring oil and gas minerals and royalties in the Utica Shale since 2012. Mr. Oldham is also a Manager of Gateway Royalty III LLC since 2016, Gateway Royalty IV LLC since 2018 and Gateway Royalty V LLC since 2019. In addition, Mr. Oldham has been actively advising Gateway Royalty II LLC and Gateway Royalty I LLC since 2014 and 2012, respectively.

Additionally, Mr. Oldham serves as Manager of Oldham Properties, Ltd. since 1990. Mr. Oldham currently serves as an Operating Partner in Mountain Capital LLC, a private equity firm out of Houston, Texas since 2015 and has served on the board of directors of Saddleback Exploration Inc., a private oil and gas company headquartered in Tulsa, Oklahoma. Mr. Oldham is also a member of the board of directors of the West Texas A&M University Foundation.

In 1979, Mr. Oldham founded Parallel Petroleum Corporation ("Parallel"), an independent energy company headquartered in Midland, Texas, which engaged in the acquisition, development and production of long-lived oil and gas properties, primarily in the Permian Basin. Parallel completed its initial public offering in 1980 and in December 2009 was acquired by an affiliate of Apollo Global Management, Inc. (formerly known as Apollo Global Management, LLC), which was sold to Samsung C&T Corporation in December of 2011. Prior to the sale to Apollo Global Management, Inc., Mr. Oldham served as Parallel's President from 1994 to 2009, Chief Executive Officer from 2004 to 2009 and director from 1979 until 2009. During Mr. Oldham's years at Parallel, some of the most notable property acquisitions were the Fullerton Property in Andrews County, Diamond M Canyon Reef Field in Scurry County and the acquisition of all of Fina's West Texas assets in July 1999. In 1992, Parallel was an early adopter of 3D seismic and drilled several Canyon Reef discoveries in Howard County, Texas and several discoveries in the Yegua/Frio Trend onshore the Gulf Coast of Texas. In 2005, horizontal drilling was successfully implemented in the Wolfcamp formation in New Mexico and the Barnett Shale in Tarrant County, Texas. In 2014, Parallel drilled the first of several horizontal wells in the Harris Field, which were large producing wells completed with engineered fracs. Parallel was the forerunner of this highly successful completion technique.

Prior to Parallel's formation, Mr. Oldham was employed by Dorchester Gas Corporation from 1976 to 1979 and KPMG Peat Marwick, LLP from 1975 to 1976. Mr. Oldham earned a Bachelor of Business Administration in Accounting from West Texas State University (now West Texas A&M University) in 1975 and was a 2012 Distinguished Alumni Award recipient. Mr. Oldham is a certified public accountant and is a member of the Permian Basin Landman's Association and the Permian Basin Producers Association.

ITEM 1A. RISK FACTORS

There are many factors that may affect our business, financial condition and results of operations and investments in us. Security holders and potential investors in our securities should carefully consider the risk factors set forth below, as well as the discussion of other factors that could affect us or investments in us included elsewhere in this Annual Report. If one or more of these risks were to materialize, our business, financial condition or results of operations could be materially and adversely affected. These known material risks could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

We are providing the following summary of the risk factors contained in this Annual Report to enhance the readability and accessibility of our risk factor disclosures. We encourage our stockholders to carefully review the full risk factors contained in this Annual Report in their entirety for additional information regarding the risks and uncertainties that could cause our actual results to vary materially from recent results or from our anticipated future results.

Risks Related to Our Business

- Crude oil, NGL and natural gas prices are volatile. Sustained volatility, or declines in, crude oil, NGL and natural gas prices could adversely affect HighPeak Energy's business, financial condition and results of operations and its ability to meet its capital expenditure obligations and other financial commitments.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of reserves.
- HighPeak Energy's development projects and acquisitions will require substantial capital expenditures. HighPeak Energy may be unable to obtain required capital or financing on satisfactory terms, including as a result of recent increases in cost of capital resulting from Federal Reserve policies or otherwise, which could reduce its ability to access or increase production and reserves.
- Restrictions in the Term Loan Credit Agreement, the Senior Credit Facility Agreement and any future debt agreements could limit HighPeak Energy's growth and ability to engage in certain activities.
- Our ability to repurchase shares under our recently announced share repurchase program is subject to certain considerations, and any share repurchases thereunder could increase the volatility of our stock prices and could diminish our cash reserves.
- Our existing and future indebtedness may adversely affect our cash flows and ability to operate our business, remain in compliance and repay our debt.
- Our results of operations and cash flows vary significantly from year to year due to the cyclical nature of the crude oil and natural gas industry.
- HighPeak Energy has experienced periods of higher costs as commodity prices have risen and inflation may adversely affect our operating results, which negatively impacts our profitability, cash flow and ability to complete development activities as planned. Continuing or worsening inflationary issues and associated changes in monetary policy have resulted in and may result in additional increases to the cost of our goods, services and personnel, which in turn could cause our capital expenditures and operating costs to rise.
- Volatility in the political, legal and regulatory environment ahead of the upcoming U.S. presidential election and political instability or armed conflict in crude oil or natural gas producing regions, such as the ongoing war between Russia and Ukraine, the Israel-Hamas conflict and OPEC+ policy decisions could have a material adverse impact on our business, financial condition or future results.
- The marketability of HighPeak Energy's production is dependent upon transportation, storage and other facilities, certain of which it does not control. If these facilities are unavailable, in whole or in part, HighPeak Energy's operations could be interrupted, and its revenues reduced.
- Certain factors could require HighPeak Energy to shut-in production or cease its capital expenditure program.
- Certain of the undeveloped leasehold acreage of HighPeak Energy's assets is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed.
- Certain factors could require HighPeak Energy to write-down the carrying values of its crude oil and natural gas properties, including commodity prices decreasing to a level such that future undiscounted cash flows from its properties are less than their carrying value.
- Drilling for and producing crude oil and natural gas are high risk activities with many uncertainties that could adversely affect HighPeak Energy's business, financial condition or results of operations.
- Hedging transactions expose HighPeak Energy to counterparty credit risk and may become more costly or unavailable.
- The standardized measure of estimated reserves may not be an accurate estimate of the current fair value of estimated crude oil and natural gas reserves.
- Properties that HighPeak Energy acquires may not produce as projected, and HighPeak Energy may be unable to determine reserve potential, identify liabilities associated with such properties or obtain protection from sellers against such liabilities.
- Adverse weather conditions may negatively affect HighPeak Energy's operating results and ability to conduct drilling activities.
- HighPeak Energy's operations are substantially dependent on the availability of sand and water. Restrictions on its ability to obtain sand and water may have an adverse effect on its financial condition, results of operations and cash flows.
- The Company's assets are located in the northeastern Midland Basin, making HighPeak Energy vulnerable to risks associated with operating in a limited geographic area.
- Unless HighPeak Energy replaces its reserves with new reserves and develops those new reserves, its reserves and production will decline, which would adversely affect future cash flows and results of operations.
- HighPeak Energy depends upon a small number of significant purchasers for the sale of most of its crude oil, NGL and natural gas production. The loss of one or more of such purchasers could, among other factors, limit HighPeak Energy's access to suitable markets for the crude oil, NGL and natural gas it produces.

- HighPeak Energy may be unable to make additional attractive acquisitions or successfully integrate acquired businesses with its current assets, and any inability to do so may disrupt its business and hinder its ability to grow.
- The unavailability or high cost of drilling rigs, equipment, supplies, personnel, frac crews and oilfield services due to commodity price volatility or supply constraints as a result of the conflict in Ukraine, the Israel-Hamas conflict, elevated interest rates and associated policies of the Federal Reserve could adversely affect HighPeak Energy's ability to execute its development plans within its budget and on a timely basis and consequently could materially and adversely affect our cash flows and results of operations.
- The IRA 2022 could accelerate the transition to a low carbon economy and could impose new costs on our operations.
- HighPeak Energy may be involved in legal proceedings that could result in substantial liabilities.
- Should our operators fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, our operators could be subject to substantial penalties and fines.
- The operations of HighPeak Energy are subject to a variety of risks arising from climate change.
- Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of crude oil and natural gas wells and adversely affect HighPeak Energy's production.
- Continued increases in interest rates could adversely affect HighPeak Energy's business.
- HighPeak Energy's business could be adversely affected by security threats, including cyber-security threats, and related disruptions.

Risks Related to Ownership of our Securities

- We are evaluating strategic alternatives, including a possible sale of our business, and there can be no assurance that we will be successful in identifying or completing any strategic alternative transactions, that any such strategic alternative transactions will result in additional value for our shareholders or that the process will not have an adverse impact on our business and shareholders.
- HighPeak Energy is a "controlled company" within the meaning of Nasdaq rules and qualifies for exemptions from certain corporate governance requirements. As a result, you do not have the same protections afforded to stockholders of companies that are not exempt from such corporate governance requirements.
- Unanticipated changes in effective tax rates or laws or adverse outcomes resulting from examination of HighPeak Energy's income or other tax returns could adversely affect HighPeak Energy's financial condition, results of operations and cash flow.
- HighPeak Energy is an emerging growth company within the meaning of the Securities Act, and if HighPeak Energy takes advantage of certain exemptions from disclosure requirements available to emerging growth companies, which could make HighPeak Energy's common stock less attractive to investors and may make it more difficult to compare its performance with other public companies.

Risks Related to Our Business

Crude oil, NGL and natural gas prices are volatile. Sustained volatility, or declines in, crude oil, NGL and natural gas prices could adversely affect HighPeak Energy's business, financial condition and results of operations and its ability to meet its capital expenditure obligations and other financial commitments.

The prices HighPeak Energy receives for its crude oil, NGL and natural gas production heavily influence its revenue, profitability, access to capital, future rate of growth and the carrying value of its properties. The markets for crude oil and natural gas have been volatile historically and are likely to remain volatile in the future. For example, during the period from January 1, 2020 through December 31, 2023, the calendar month average NYMEX WTI crude oil price per Bbl ranged from a low of $16.70 to a high of $114.34, and the last trading day NYMEX natural gas price per MMBtu ranged from a low of $1.50 to a high of $9.35. For the month of April 2020, the calendar month average NYMEX WTI crude oil price was $16.70 per Bbl and the last trading day NYMEX natural gas price was $1.63 per MMBtu. One of the factors which caused the fall in prices was OPEC+ being unable to reach an agreement on production levels for crude oil, which resulted in Saudi Arabia and Russia initiating efforts to increase production. The convergence of these events, along with the significantly reduced demand because of the COVID-19 pandemic, created an unprecedented global crude oil and natural gas supply and demand imbalance, reduced global crude oil and natural gas storage capacity, caused crude oil and natural gas prices to decline significantly and resulted in continued volatility in crude oil, NGL and natural gas prices into the second quarter of 2020. Prices have recovered to pre-pandemic levels, with the calendar month average NYMEX WTI crude oil price of $72.12 per Bbl and the last trading day NYMEX natural gas price of $2.71 per MMBtu for the month of December 2023. However, there can be no certainty that commodity prices will sustain at these levels or continue to increase.

Likewise, NGL, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which has different uses and pricing characteristics, have also fluctuated widely during this period. The prices HighPeak Energy receives for its production, and the levels of HighPeak Energy's production, will depend on numerous factors beyond HighPeak Energy's control, which include the following:

- worldwide and regional economic conditions, including elevated interest rates and associated policies of the Federal Reserve, impacting the global supply and demand for crude oil, NGL and natural gas;
- the price and quantity of foreign imports of crude oil, NGL and natural gas;
- domestic and global political and economic conditions, such as the upcoming U.S. presidential election, the ongoing conflict in Ukraine, the Israel-Hamas conflict, socio-political unrest and instability, terrorism or hostilities in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- the occurrence or threat of epidemic or pandemic diseases, such as the recent outbreak of COVID-19, or any government response to such occurrence or threat;
- actions of OPEC, its members and other state-controlled crude oil companies relating to crude oil price and production controls;
- the level of global exploration, development and production;
- the level of global inventories;
- prevailing prices, and expectations regarding future prices, on local price indexes in the areas in which HighPeak Energy operates;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels, including the potential acceleration of the development of alternative fuels as a result of the IRA 2022 or otherwise;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

Lower commodity prices may reduce HighPeak Energy's cash flow and access to capital markets. If HighPeak Energy is unable to obtain needed capital or financing on satisfactory terms, its ability to develop future reserves could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with lower crude oil and natural gas prices may adversely affect drilling economics and HighPeak Energy's ability to raise capital, which may require it to re-evaluate and postpone or eliminate its development program, and result in the reduction of some proved undeveloped reserves and related standardized measure. If HighPeak Energy is required to curtail its drilling program, HighPeak Energy may be unable to hold leases that are scheduled to expire, which may further reduce reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect HighPeak Energy's future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of reserves.

Numerous uncertainties are inherent in estimating quantities of crude oil and natural gas reserves. Our estimates of our SEC reserves are based upon average commodity prices over the prior 12 months, which may not reflect actual prices received for our production. For example, our reserve volumes and PV-10 as disclosed in this Annual Report are based on assumed commodity prices of $78.22 per Bbl of crude oil and NGL and $2.637 per MMBtu of natural gas as of December 31, 2023, which are somewhat higher than the December 31, 2023 front-month forward pricing of $71.65 per Bbl of crude oil and $2.514 per Mcf of natural gas. Accordingly, you are cautioned not to place undue weight on our reserve volumes or PV-10 based on such pricing when evaluating our financial condition or an investment in our securities. The process of estimating crude oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves. To prepare the reserve estimates included in this Annual Report, CG&A analyzed available geological, geophysical, production and engineering data and projected the production rates and timing of development expenditures. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, crude oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary from the estimates included in this Annual Report. For instance, initial production rates reported by HighPeak Energy or other operators may not be indicative of future or long-term production rates, and recovery efficiencies may be worse than expected and production declines may be greater than estimated and may be more rapid and irregular compared with initial production rates. In addition, estimates of proved reserves may be adjusted to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of reserves. Moreover, there can be no assurance that reserves will ultimately be produced or that proved undeveloped reserves will be developed within the periods anticipated.

HighPeak Energy's development projects and acquisitions will require substantial capital expenditures. HighPeak Energy may be unable to obtain required capital or financing on satisfactory terms, including as a result of recent increases in the cost of capital resulting from Federal Reserve policies or otherwise, which could reduce its ability to access or increase production and reserves.

The crude oil and natural gas industry is capital-intensive. HighPeak Energy has evaluated multiple development scenarios under multiple potential commodity price assumptions. Under its current 2024 development program, HighPeak Energy would expect to incur approximately $450 to $525 million of capital expenditures for drilling, completion, facilities and equipping costs and $50 - $60 million for field infrastructure, land and other costs. The ability to make these capital expenditures will be highly dependent on the price of crude oil and available funding of HighPeak Energy. Commodity prices have recovered from their April 2020 lows, with the calendar month average NYMEX WTI price of $72.12 per Bbl and last trading day NYMEX natural gas price of $2.71 per MMBtu for the month of December 2023. HighPeak Energy began the year with six rigs, then ran a five-rig program from February to mid-April of 2023 and subsequently decreased to a three-rig program beginning in May 2023 and a two-rig program from June 2023 to the end of October 2023 when it increased to a three-rig program through yearend. HighPeak Energy expects to average two (2) drilling rigs and one (1) frac crew during 2024. However, HighPeak Energy recognizes that commodity prices remain highly volatile and that its liquidity is limited, and as a result, there is no certainty that HighPeak Energy will operate a two (2) rig development program in the future.

HighPeak Energy expects to fund its forecasted capital expenditures with cash on its balance sheet, cash generated by operations, through borrowings under the Senior Credit Facility Agreement if needed and, depending on market circumstances, potential future debt or equity offerings. For terms of the Term Loan Credit Agreement and Senior Credit Facility Agreement, see Note 7 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Cash flows from operations are subject to significant uncertainty. As a result, the amount of liquidity that HighPeak Energy will have in the future is uncertain.

HighPeak Energy's financing needs may require it to alter or increase its capitalization substantially through the issuance of debt or equity securities or the sale of assets. The availability and cost of these capital sources is cyclical, and these capital sources may not remain available, or we may not be able to obtain financing at a reasonable cost in the future. For example, due to the high levels of inflation in the U.S., the Federal Reserve and other central banks increased interest rates multiple times in 2022 and 2023, and although the Federal Reserve has indicated that such increases have ceased going into 2024, uncertainty remains as to when or if such elevated rates may be decreased. Such increased interest rates have increased the cost of capital and may prevent us from being able to obtain debt financing at favorable rates, or at all, which would materially impact our operations. In addition, conditions in the global capital markets have been volatile due to the conflict in Ukraine, the Israel-Hamas conflict or otherwise, making terms for certain types of financing difficult to predict, and in certain cases, resulting in certain types of financing being unavailable. Further, the issuance of additional indebtedness would require that an additional portion of cash flow from operations be used for the payment of interest and principal on its indebtedness, thereby further reducing its ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities would be dilutive to existing stockholders. The actual amount and timing of future capital expenditures may differ materially from estimates as a result of, among other things: commodity prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in actual capital expenditures, which would negatively impact HighPeak Energy's ability to increase production.

HighPeak Energy's cash flow from operations and access to capital are subject to several variables, including:

- the prices at which HighPeak Energy's production is sold;
- proved reserves;
- the amount of hydrocarbons HighPeak Energy is able to produce from its wells;
- HighPeak Energy's ability to acquire, locate and produce new reserves;
- the amount of HighPeak Energy's operating expenses;
- cash settlements from HighPeak Energy's derivative activities;
- restrictions on capital expenditures in certain circumstances under the Term Loan Credit Agreement or the Senior Credit Facility Agreement;
- HighPeak Energy's ability to obtain additional debt financing, including increases to the Term Loan Credit Agreement or the Senior Credit Facility Agreement;
- the duration and scope of the ongoing war between Russia and Ukraine and conflict in the Middle East, including between Israel and Hamas;
- HighPeak Energy's ability to obtain storage capacity for the crude oil it produces;
- restrictions in the instruments governing HighPeak Energy's debt on HighPeak Energy's ability to incur additional indebtedness; and

- HighPeak Energy's ability to access the public or private capital markets.

Should HighPeak Energy's revenues decrease as a result of lower crude oil, NGL and natural gas prices, operational difficulties, declines in reserves or for any other reason, HighPeak Energy may have limited ability to obtain the capital necessary to sustain operations at expected levels. If additional capital is needed, HighPeak Energy may not be able to obtain debt or equity financing on terms acceptable to it, if at all, due to elevated interest rates and associated policies of the Federal reserve, or otherwise. If cash flow generated by HighPeak Energy's operations or available debt financing, including borrowings under the Credit Agreements, are insufficient to meet its capital requirements, the failure to obtain additional financing could result in a curtailment of the development of HighPeak Energy's properties, which in turn could lead to a decline in reserves and production and could materially and adversely affect HighPeak Energy's business, financial condition and results of operations. If HighPeak Energy seeks and obtains additional financing, subject to the restrictions in the instruments governing its existing debt, the addition of new debt to existing debt levels could intensify the operational risks that HighPeak Energy will face. Further, adding new debt could limit HighPeak Energy's ability to service existing debt service obligations.

Restrictions in the Term Loan Credit Agreement, the Senior Credit Facility Agreement and any future debt agreements could limit HighPeak Energy's growth and ability to engage in certain activities.

The terms and conditions governing the Term Loan Credit Agreement, the Senior Credit Facility Agreement and any future additional indebtedness are expected to:

- require HighPeak Energy to dedicate a portion of cash flow from operations to service its debt, thereby reducing the cash available to finance operations and other business activities and could limit its flexibility in planning for or reacting to changes in its business and the industry in which it operates;
- increase vulnerability to economic downturns and adverse developments in HighPeak Energy's business;
- place restrictions on HighPeak Energy's ability to engage in certain business activities, including without limitation, to raise capital, obtain additional financing (whether for working capital, capital expenditures or acquisitions) or to refinance indebtedness, grant or incur liens on assets, pay dividends or make distributions in respect of its capital stock, make investments, amend or repay subordinated indebtedness, sell or otherwise dispose of assets, businesses or operations and engage in business combinations or other fundamental changes;
- potentially place HighPeak Energy at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- limit management's discretion in operating HighPeak Energy's business.

Our debt instruments also contain provisions that could have the effect of making it more difficult for a third party to acquire control of us. The Term Loan Credit Agreement and the Senior Credit Facility Agreement provide that a change of control constitutes an event of default and would permit the lenders to declare the indebtedness thereunder to be immediately due and payable. Our future credit facilities may contain similar provisions. The need to repay all such indebtedness may deter potential third parties from acquiring us.

HighPeak Energy's ability to meet its expenses and its current and future debt obligations and comply with the covenants and restrictions contained therein will depend on its future performance, which will be affected by financial, business, economic, industry, regulatory and other factors, many of which are beyond HighPeak Energy's control. If market or other economic conditions deteriorate, HighPeak Energy's ability to comply with these covenants may be impaired. HighPeak Energy cannot be certain that its cash flow will be sufficient to enable it to pay the principal and interest on its debt and meet its other obligations. If HighPeak Energy does not have enough money, HighPeak Energy may be required to refinance all or part of its debt, sell assets, borrow more money or raise equity. HighPeak Energy may not be able to refinance its debt, sell assets, borrow more money or raise equity on terms acceptable to it, or at all. For example, HighPeak Energy's future debt agreements may require the satisfaction of certain conditions, including coverage and leverage ratios, to borrow money. HighPeak Energy's future debt agreements may also restrict the payment of dividends and distributions by certain of its subsidiaries to it, which could affect its access to cash. In addition, HighPeak Energy's ability to comply with the financial and other restrictive covenants in the agreements governing its indebtedness will be affected by the levels of cash flow from operations and future events and circumstances beyond HighPeak Energy's control. Breach of these covenants or restrictions could result in an event of default under HighPeak Energy's existing and/or future financing arrangements, which, if not cured or waived, could permit the lenders to accelerate all indebtedness outstanding thereunder. Upon acceleration, the debt would become immediately due and payable, together with accrued and unpaid interest, and any lenders' commitment to make further loans to HighPeak Energy may terminate. Even if new financing were then available, it may not be on terms that are acceptable to HighPeak Energy. Additionally, upon the occurrence of an event of default under HighPeak Energy's financing agreements, the affected lenders may exercise remedies, including through foreclosure, on the collateral, if any, securing any such secured financing arrangements. Moreover, any subsequent replacement of HighPeak Energy's financing arrangements may require it to comply with more restrictive covenants which could further restrict business operations.

The Company had an aggregate maximum commitment amount of $100.0 million and commitment amount of $75.0 million with respect to the Senior Credit Facility Agreement as of December 31, 2023. The Term Loan Credit Agreement also limits the amounts HighPeak Energy can borrow under the Senior Credit Facility Agreement to $100.0 million.

Our ability to repurchase shares under our recently announced share repurchase program is subject to certain considerations, and any share repurchases thereunder could increase the volatility of our stock prices and could diminish our cash reserves.

We recently adopted a share repurchase program that authorizes us to repurchase up to an aggregate $75.0 million of shares of our common stock. Our repurchase program expires December 31, 2024 and does not obligate HighPeak to repurchase any specific dollar amount or to acquire any specific number of shares and will depend upon, among other things, our earnings, liquidity, capital requirements, financial condition and other factors deemed relevant by our board of directors. Additionally, our Term Loan Credit Agreement limits our ability to repurchase shares of our common stock. Further, our share repurchases could affect our share trading prices, increase their volatility, reduce our cash reserves and may be suspended or terminated at any time, which may result in a decrease in the trading prices of our stock. Our Board of Directors may amend or suspend the share repurchase program at any time in its discretion. We can provide no assurances that we will repurchase shares of our common stock within the authorized amount or at all.

Our existing and future indebtedness may adversely affect our cash flows and ability to operate our business, remain in compliance and repay our debt.

In September 2023, in connection with the entry into the Term Loan Credit Agreement, the Prior Credit Agreement was terminated. As of December 31, 2023, we had $1.2 billion of total indebtedness, including $1.2 billion outstanding of our Term Loan Credit Agreement and no indebtedness outstanding under our Senior Credit Facility Agreement, and available capacity under our Senior Credit Facility Agreement of approximately $68.9 million. The entirety of our $1.2 billion of total indebtedness is maturing in 2026.

Among other events of default, an event of default will occur under the Term Loan Credit Agreement and the Senior Credit Facility Agreement if HighPeak Energy should fail to make any payment (whether of principal or interest and regardless of amount) in respect of any material debt, when and as the same shall become due and payable and such failure to pay continues beyond any applicable grace period, or any event or condition occurs that results in any material debt becoming due prior to its scheduled maturity or that enables or permits (with or without the giving of notice, the lapse of time or both) the holder or holders of any material debt or any trustee or agent on its or their behalf to cause any material debt to become due, or to require the redemption thereof or any offer to redeem to be made in respect thereof, prior to its scheduled maturity or require HighPeak Energy to make an offer in respect thereof and such event or condition continues beyond any applicable grace period. In the event of a default under these circumstances, lenders could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due and payable.

We may be unable to repay amounts due when they become due, and our ability to refinance our indebtedness on reasonable terms may be limited. Although our debt agreements contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to several significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial, and some of which may be secured by our assets. Our current level of indebtedness could have important consequences, such as:

- making it difficult for us to satisfy our obligations under our indebtedness and contractual and commercial commitments;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate purposes;
- limiting our flexibility to plan for, or react to, changes in our business and the industry in which we operate;
- restricting us from making strategic acquisitions or exploiting business opportunities;
- placing us at a competitive disadvantage compared to our competitors that have less debt;
- limiting our ability to borrow additional funds; and
- decreasing our ability to compete effectively or operate successfully under adverse economic and industry conditions.

Our results of operations and cash flows vary significantly from year to year due to the cyclical nature of the crude oil and natural gas industry.

We expect our results of operations and cash flows to vary significantly from year to year due to the cyclical nature of the crude oil and natural gas industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. In addition, our future cash flows may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and as a result, our ability to generate cash flows from operations and to pay our debt. Many of these factors, such as crude oil, NGL and natural gas prices, regulatory factors, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control. If we do not generate sufficient cash flows from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, any alternative financing plans that we undertake, if necessary, may not allow us to meet our debt obligations. We cannot assure you that any refinancing or debt restructuring would be possible, that any assets could be sold or that, if sold, the timing of the sales and the amount of proceeds realized from those sales would be favorable to us or that additional financing could be obtained on acceptable terms. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and could require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest or principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness.

In addition, if we fail to comply with the covenants or other terms of our Credit Agreements, our lenders will have the right to accelerate the maturity of that debt and foreclose upon the collateral, if any, securing that debt. Realization of any of these factors could adversely affect our financial condition.

HighPeak Energy experiences periods of higher costs when commodity prices rise and inflation may adversely affect our operating results, which could negatively impact our profitability, cash flow and ability to complete development activities as planned. Continuing or worsening inflationary issues and associated changes in monetary policy have resulted in and may result in additional increases to the cost of our goods, services and personnel, which in turn could cause our capital expenditures and operating costs to rise.

Historically, capital and operating costs have risen during periods of increasing crude oil, NGL and natural gas prices. Inflationary factors such as increases in the labor costs, material costs and overhead costs may adversely affect our operating results. These cost increases have resulted from a variety of factors that HighPeak Energy will be unable to control, such as increases in the cost of electricity, steel and other raw materials; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in HighPeak Energy's revenue if commodity prices rise, thereby negatively impacting its profitability, cash flow and ability to complete development activities as scheduled and on budget. A high rate of inflation may have an adverse effect on HighPeak Energy's operating results and this impact may be magnified to the extent that HighPeak Energy's ability to participate in the commodity price increases is limited by its derivative activities, if any.

Elevated inflation rates throughout 2023 and inflationary pressures have resulted in and may result in additional increases to the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise. Due to the high levels of inflation in the U.S., the Federal Reserve and other central banks increased interest rates multiple times in 2022 and 2023, and although the Federal Reserve has indicated that such increases have ceased going into 2024, uncertainty remains as to when or if such elevated rates may be decreased. To the extent rates remain high, this could have the effects of raising the cost of capital and depressing economic growth, either of which—or the combination thereof—could hurt the financial and operating results of our business. To the extent elevated inflation remains, we may experience further cost increases for our operations, including oilfield services, labor costs and equipment if our drilling activity increases.

Higher crude oil and natural gas prices, continued inflation and supply chain issues as well as an increase in demand for services may cause the costs of materials and services to continue to rise. We cannot predict any future trends in the rate of inflation, and a significant increase in inflation, to the extent we are unable to recover higher costs through higher crude oil and natural gas prices and revenues, would negatively impact our business, financial condition and results of operations.

Volatility in the political, legal and regulatory environments ahead of the upcoming U.S. presidential election and political instability or armed conflict in crude oil or natural gas producing regions, such as the ongoing war between Russia and Ukraine, the Israel-Hamas conflict and OPEC+ policy decisions could have a material adverse impact on our business, financial condition or future results.

Our business, financial condition and future results are subject to political and economic risks and uncertainties, including volatility in the political, legal and regulatory environments ahead of the upcoming U.S. presidential election and instability resulting from civil unrest, political demonstrations, mass strikes or armed conflict or other crises in crude oil or natural gas producing areas such as the ongoing war between Russia and Ukraine and the Israel-Hamas conflict.

The United States and other countries and certain international organizations have imposed broad-ranging and severe economic sanctions on Russia and certain Russian individuals, banking entities and corporations as a response, and additional sanctions may be imposed in the future. This conflict and the resulting sanctions and concerns regarding global energy security have contributed to increases and volatility in the prices for crude oil and natural gas. The length, impact, and outcome of the ongoing war between Russia and Ukraine is highly unpredictable, and such events or any further hostilities in Ukraine or elsewhere could severely impact the world economy and may adversely affect our financial condition. Furthermore, escalations of the Israel-Hamas conflict may result in heightened geopolitical risks for crude oil and natural gas markets, given the significant share of global oil supply in the Middle East. While the Company does not have operations overseas, these conflicts elevate the likelihood of supply chain disruptions, heightened volatility in crude oil and natural gas prices and negative effects on our ability to raise additional capital when required and could have a material adverse impact on our business, financial condition or future results.

Currently, global crude oil inventories are low relative to historical levels and supply from OPEC+ and other crude oil producing nations are not expected to be sufficient to meet forecasted crude oil demand growth for the next few years. It is believed that many OPEC+ countries will be unable to increase their production levels or even produce at expected levels due to their lack of capital investments in developing incremental crude oil supplies over the past few years. In November 2023, OPEC+ determined to reduce production beginning in early 2024 by 2.2 million Bopd, due to the uncertainty surrounding the global economic and crude oil market outlooks. Furthermore, sanctions and import bans on Russian crude oil have been implemented by various countries in response to the war in Ukraine, further impacting global crude oil supply. Still, crude oil and natural gas prices have declined from the highs experienced in second quarter of 2022 and could decrease or increase with any changes in demand due to, among other things, uncertainty and volatility from global supply chain disruptions attributable to the pandemic, the ongoing conflict in Ukraine, the Israel-Hamas conflict, international sanctions, speculation as to future actions by OPEC+, increasing inflation and government efforts to reduce inflation, and possible changes in the overall health of the global economy, including a prolonged recession. Further, the volatility in crude oil and natural gas prices could accelerate a transition away from fossil fuels, resulting in reduced demand over the longer term. To what extent these and other external factors (such as government action with respect to climate change regulation) ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors, including future developments, which are not within our control and cannot be accurately predicted.

The marketability of HighPeak Energy's production is dependent upon transportation, storage and other facilities, certain of which it does not control. If these facilities are unavailable, in whole or in part, HighPeak Energy's operations could be interrupted, and its revenues reduced.

The marketability of HighPeak Energy's crude oil and natural gas production depends in part upon the availability, proximity and capacity of transportation, processing and storage facilities owned and operated by third parties. Any significant interruption in service from, damage to, or lack of available capacity in these systems and facilities may result in the shutting-in of producing wells or the delay or discontinuance of development plans for our properties. Federal and state regulation of crude oil, NGL and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines or processing facilities, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process, transport or market crude oil, NGLs and natural gas. In addition, even if these systems and facilities remain open generally, certain quality specifications implemented thereby may restrict our ability to utilize such systems and facilities. Further, insufficient production from wells to support the construction of pipeline facilities by purchasers or a significant disruption in the availability of HighPeak Energy's or third-party transportation facilities or other production facilities could adversely impact HighPeak Energy's ability to deliver to market or produce crude oil and natural gas and thereby cause a significant interruption in HighPeak Energy's operations. If, in the future, HighPeak Energy is unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounters production related difficulties, it may be required to shut-in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the crude oil and natural gas produced from HighPeak Energy's fields, would materially and adversely affect its financial condition and results of operations.

Production may be interrupted, or shut-in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, various contaminants, field labor issues or strikes, or we might voluntarily curtail production in response to market or other conditions. Some of these risks may be exacerbated by other risks that we face. For instance, the potential exists for some of our wells to produce high levels of hydrogen sulfide, a highly toxic, naturally-occurring gas frequently associated with crude oil and natural gas production. Safe handling of hydrogen sulfide gas requires highly skilled operations and field personnel as well as specialized infrastructure, treating facilities, disposal facilities, and/or third-party sour gas takeaway. If we are unable to successfully secure adequate treatment and/or sour gas takeaway capacity from third parties when and if necessary, our production may be adversely impacted. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flows and results of operations.

Certain factors could require HighPeak Energy to shut-in production or cease its capital expenditure program.

During 2020, the reduction in global demand caused by COVID-19, coupled with the actions of foreign crude oil producers such as Saudi Arabia and Russia, materially decreased global crude oil prices and generated a surplus of crude oil. This significant surplus created a saturation of storage and caused imminent crude storage constraints, which led to, and in the future may further lead to the shut-in of production of our wells due to the lack of sufficient markets or the lack of availability and capacity of processing, gathering, storing and transportation systems. Additionally, several state crude oil and natural gas authorities, including the TRRC, implemented or considered implementing crude oil and natural gas production limits in an effort to stabilize declining commodity prices. To the extent adopted, such production limits could not only reduce our revenue, but also, if wells are required to be shut-in for extended periods of time due to such production limits, result in expenditures related to well plugging and abandonment. Cost increases necessary to bring wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in HighPeak Energy's proved reserve estimates and potential impairments and associated charges to its earnings. HighPeak Energy curtailed the majority of its production in April 2020. However, prices increased, and HighPeak Energy management began returning its wells to production in mid-July 2020. As of December 31, 2023, HighPeak Energy was running a three-rig program and expects to average two (2) drilling rigs and one (1) frac crew during 2024 under our current development plan. HighPeak Energy will continue to monitor the extent by which prices continue to increase and/or stabilize as we execute our capital expenditure program. Any shut-in or curtailment of the crude oil, NGL and natural gas produced from HighPeak Energy's fields could adversely affect its financial condition and results of operations.

Certain of the undeveloped leasehold acreage of HighPeak Energy's assets is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed.

As of December 31, 2023, approximately 64% of HighPeak Energy's acreage was held by production. Generally, the leases for net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases or the leases are extended or renewed. From 2024 through 2026, approximately 21%, 14% and 1%, respectively, of the net acreage associated with the leases are set to expire. If the leases expire and HighPeak Energy is unable to renew the leases, HighPeak Energy will lose its right to develop the related properties. Although HighPeak Energy intends to hold substantially all these leases through its development drilling program or extend substantially all the net acreage associated with identified drilling locations through a combination of exploratory and development drilling, a portion of such leases may be extended or renewed. Additionally, any payments related to such extensions or renewals may be more than anticipated. Please see "Items 1 and 2: Business and Properties—Reserve Data—Undeveloped Acreage Expirations" for more information regarding acreage expirations and our plans for extending our acreage. HighPeak Energy's ability to drill and develop its acreage and establish production to maintain its leases depends on a number of uncertainties, including crude oil, NGL and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing, frac sand and distribution systems, regulatory approvals and other factors.

Certain factors could require HighPeak Energy to write-down the carrying values of its crude oil and natural gas properties, including commodity prices decreasing to a level such that future undiscounted cash flows from its properties are less than their carrying value.

Accounting rules require that HighPeak Energy periodically review the carrying value of its properties for possible impairment, whenever changes in events or circumstances indicate that the carrying value of its properties may not be recoverable. If there is an indication the carrying value of the assets may not be recovered, an impairment loss is recognized if the sum of the expected future cash flows is less than the carrying amount of the assets. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, HighPeak Energy may be required to write-down the carrying value of its properties. A write-down constitutes a non-cash impairment charge to earnings. Historically, crude oil, NGL and natural gas prices have been volatile. For example, during the period from January 1, 2020 through December 31, 2023, the calendar month average NYMEX WTI crude oil price per Bbl ranged from a low of $16.70 to a high of $114.34, and the last trading day NYMEX natural gas price per MMBtu ranged from a low of $1.50 to a high of $9.35.

Likewise, NGL, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which has different uses and pricing characteristics, have also fluctuated widely during this period.

Sustained levels of depressed commodity prices, or further decreases, in the future could result in impairments of HighPeak Energy's properties, which could have a material adverse effect on results of operations for the periods in which such charges are taken. HighPeak Energy could experience material write-downs as a result of lower commodity prices or other factors, including low production results or high lease operating expenses, capital expenditures or transportation fees.

Part of HighPeak Energy's business strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

HighPeak Energy's operations involve utilizing some of the latest drilling and completion techniques as developed by HighPeak Energy and its service providers. The difficulties HighPeak Energy may face drilling horizontal wells may include, among others:

- landing its wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- Running and cementing casing throughout the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Difficulties that HighPeak Energy may face while completing its wells include the following, among others:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Use of new technologies may not prove successful and could result in significant cost overruns or delays or reductions in production, and, in extreme cases, the sidetracking or abandonment of a well. In addition, certain of the new techniques HighPeak Energy adopts may cause irregularities or interruptions in production due to offset wells being shut-in and the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, the results of drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer and emerging formations and areas have limited or no production history and, consequently, HighPeak Energy may be more limited in assessing future drilling results in these areas. If its drilling results are less than anticipated, the return on investment for a particular project may not be as attractive as anticipated, and HighPeak Energy could incur material write downs of unevaluated properties and the value of undeveloped acreage could decline in the future.

For example, potential complications associated with the new drilling and completion techniques that HighPeak Energy intends to utilize may cause HighPeak Energy to be unable to develop its assets in line with current expectations and projections. Further, recent well results may not be indicative of HighPeak Energy's future well results.

Drilling for and producing crude oil and natural gas are high risk activities with many uncertainties that could adversely affect HighPeak Energy's business, financial condition or results of operations.

HighPeak Energy's future financial condition and results of operations will depend on the success of its development, production and acquisition activities, which are subject to numerous risks beyond its control, including the risk that drilling will not result in commercially viable crude oil and natural gas production.

HighPeak Energy’s decisions to develop or purchase prospects or properties will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of reserves.” In addition, the cost of drilling, completing and operating wells will often be uncertain.

Further, many factors may curtail, delay or cancel scheduled drilling operations, including:

- delays imposed by, or resulting from, compliance with regulatory requirements, including the IRA 2022, limitations on wastewater disposal, emission of GHGs and hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- lack of availability of water and electricity;
- adverse weather conditions;
- issues related to compliance with environmental regulations;
- environmental hazards, such as crude oil and natural gas leaks, crude oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in crude oil and natural gas prices;
- limited availability of financing on acceptable terms;
- title issues; and
- other market limitations in HighPeak Energy's industry.

We have entered into certain long-term contracts that require us to pay fees to our service providers based on minimum volumes regardless of actual volume throughput and that may limit our ability to use other service providers.

From time to time, HighPeak Energy has entered into and may in the future enter into certain crude oil, natural gas or produced water gathering or transportation agreements, natural gas processing agreements, NGL transportation agreements, produced water disposal agreements or similar commercial arrangements with midstream companies and contracts to provide sand or other drilling and completion or operating supplies. Certain of these agreements require HighPeak Energy to meet minimum volume commitments, often regardless of actual throughput.

In May 2021, the Company entered into a crude oil marketing contract with Delek as the purchaser and DKL Permian Gathering, LLC ("DKL") as the gatherer and transporter. The contract includes the Company's current and future crude oil production from the majority of its horizontal wells in Flat Top where DKL is constructing a crude oil gathering system and custody transfer meters to most of the Company's central tank batteries. The contract contains a minimum volume commitment commencing October 2021 based on the gross barrels delivered at the Company's central tank battery facilities and is 5,000 Bopd for the first year, 7,500 Bopd for the second year and 10,000 Bopd for the remaining eight years of the contract. However, the Company has the ability under the contract to cumulatively bank excess volumes delivered to offset future minimum volume commitments. For the period from October 1, 2021 to December 31, 2023, the Company has delivered approximately 29,600 Bopd under the contract. The remaining monetary commitment as of December 31, 2023, if the Company never delivers any additional volumes under the agreement, is approximately $7.8 million.

The Company is party to an amended agreement whereby it has agreed to purchase at least 1.6 million tons of frac sand over a two-year period beginning July 1, 2022. There are stipulations in the agreement that reduce this commitment should we experience a downturn in crude oil prices. As of December 31, 2023, the Company has purchased approximately 1.2 million tons of frac sand under the contract. However, generally if the Company never takes delivery of any additional frac sand under the agreement, the monetary commitment that remains as of December 31, 2023 is approximately $9.5 million.

If HighPeak Energy has insufficient production to meet the minimum volume commitments under any of these agreements or if HighPeak Energy fails to take delivery of supplies which it committed to, HighPeak Energy's cash flow from operations will be reduced, which may require HighPeak Energy to reduce or delay its planned investments and capital expenditures, or seek alternative means of financing, all of which may have a material adverse effect on HighPeak Energy's results of operation.

Hedging transactions expose HighPeak Energy to counterparty credit risk and may become more costly or unavailable.

HighPeak is required under the Term Loan Credit Agreement and Senior Credit Facility Agreement to hedge certain quantities of its projected crude oil production. Hedging transactions expose HighPeak Energy to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and HighPeak Energy may not be able to realize the benefit of the derivative contract. Derivative instruments also expose HighPeak Energy to the risk of financial loss in some circumstances, including when there is an increase in the differential between the underlying price in the derivative instrument and actual prices received or there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If HighPeak Energy enters into derivative instruments that require cash collateral and commodity prices or interest rates change in an adverse manner, our cash otherwise available for use in operations would be reduced which could limit HighPeak Energy's ability to make future capital expenditures and make payments on indebtedness. Future collateral requirements will depend on arrangements with counterparties, highly volatile crude oil, NGL and natural gas prices and interest rates.

In addition, derivative arrangements could limit the benefits to be received from increases in the prices for natural gas, NGL and crude oil, which could also have an adverse effect on HighPeak Energy's financial condition. If natural gas, NGL or crude oil prices upon settlement of derivative swap contracts exceed the price at which commodities have been hedged, HighPeak Energy will be obligated to make cash payments to counterparties, which could, in certain circumstances, be significant.

In addition, U.S. regulators adopted a final rule in November 2019 implementing a new approach for calculating the exposure amount of derivative contracts under the applicable agencies' regulatory capital rules, referred to as the standardized approach for counterparty credit risk ("SA-CCR"). As adopted, certain financial institutions are required to comply with the new SA-CCR rules beginning on January 1, 2022. The new rules could significantly increase the capital requirements for certain participants in the over-the-counter derivatives market in which HighPeak Energy participates. These increased capital requirements could result in significant additional costs being passed through to end-users or reduce the number of participants or products available in the over-the-counter derivatives market. The effects of these regulations could reduce HighPeak Energy's hedging opportunities, or substantially increase the cost of hedging, which could adversely affect HighPeak Energy's business, financial condition and results of operations.

The standardized measure of estimated reserves may not be an accurate estimate of the current fair value of estimated crude oil and natural gas reserves.

Standardized measure is a reporting convention that provides a common basis for comparing crude oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires historical twelve-month pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. For example, our reserve volumes and PV-10 as disclosed in this Annual Report are based on assumed commodity prices of $78.22 per Bbl of crude oil and NGL and $2.637 per MMBtu of natural gas as of December 31, 2023, which are substantially higher than December 31, 2023 front-month forward pricing of $71.65 per Bbl of crude oil and $2.514 per Mcf of natural gas. Consequently, it may not reflect the prices ordinarily received or that will be received for crude oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the crude oil and natural gas properties. As a result, estimates included in this Annual Report of future net cash flow may be materially different from the future net cash flows that are ultimately received. Therefore, the standardized measure of estimated reserves included in this Annual Report should not be construed as an accurate estimate of the current fair value of such proved reserves. Accordingly, you are cautioned not to place undue weight on our reserve volumes or PV-10 based on such pricing when evaluating our financial condition or an investment in our securities.

You should not assume the present value of future net revenues from the reserves presented in this Annual Report is the current market value of the estimated reserves of our assets. Actual future prices and costs may differ materially from those used in the present value estimate. If spot prices are below such calculated amounts, using more recent prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits.

Properties that HighPeak Energy acquires may not produce as projected, and HighPeak Energy may be unable to determine reserve potential, identify liabilities associated with such properties or obtain protection from sellers against such liabilities.

From time to time, HighPeak Energy enters into agreements to effect certain acquisitions, whereby it acquires crude oil and natural gas producing properties and undeveloped acreage. To the extent these acquisitions include producing crude oil and natural gas properties, acquiring crude oil and natural gas properties requires HighPeak Energy to assess reservoir and infrastructure characteristics, including such assets and/or other recoverable reserves, future crude oil and natural gas prices and their applicable differentials, development and operating costs, and potential liabilities, including environmental liabilities. In connection with these assessments, HighPeak Energy performs a review of the subject properties that it believes to be generally consistent with industry practices. Such assessments are inexact and inherently uncertain. For these reasons, the properties that HighPeak Energy acquires, or may acquire in the future, may not produce as expected. In connection with the assessments, HighPeak Energy performs a review of the subject properties, but such a review may not reveal all existing or potential problems. In the course of due diligence, HighPeak Energy may not review every well, pipeline or associated facility. HighPeak Energy cannot necessarily observe structural and environmental problems, such as groundwater contamination, when a review is performed. HighPeak Energy may be unable to obtain contractual indemnities from the seller for liabilities created prior to HighPeak Energy's purchase of the property. HighPeak Energy may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with its expectations. Additionally, the success of future acquisitions will depend on HighPeak Energy's ability to integrate effectively the then-acquired business into its then-existing operations. The process of integrating acquired assets may involve unforeseen difficulties and may require a disproportionate amount of managerial and financial resources. HighPeak Energy's failure to achieve consolidation savings, to incorporate the additionally acquired assets into its then-existing operations successfully, or to minimize any unforeseen operational difficulties, or the failure to acquire future assets at all, could have a material adverse effect on its financial condition and results of operations.

HighPeak Energy is not the operator on all its acreage or drilling locations, and, therefore, HighPeak Energy is not able to control the timing of exploration or development efforts, associated costs or the rate of production of any non-operated assets, and could be liable for certain financial obligations of the operators or any of its contractors, to the extent such operator or contractor is unable to satisfy such obligations.

HighPeak Energy is not the operator on all its acreage or drilling locations, and there is no assurance that it will operate all HighPeak Energy's other future drilling locations. As a result, HighPeak Energy will have limited ability to exercise influence over the operations of the drilling locations operated by its partners and there is the risk that HighPeak Energy's partners may at any time have economic, business or legal interests or goals that are inconsistent with ours. Furthermore, the success and timing of development activities operated by its partners will depend on several factors that will be largely outside of HighPeak Energy's control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the approval of other participants in drilling wells;

- the selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations and associated costs of some of HighPeak Energy's drilling locations could prevent the realization of targeted returns on capital in drilling or acquisition activities. Further, HighPeak Energy may be liable for certain financial obligations of the operator of a well in which it owns a working interest to the extent such operator becomes insolvent and cannot satisfy such obligations. Similarly, HighPeak Energy may be liable for certain obligations of contractors to the extent such contractor becomes insolvent and cannot satisfy their obligations. The satisfaction of such obligations could have a material adverse effect on HighPeak Energy's financial condition. For more information about certain of HighPeak Energy's assets, see the sections entitled "Items 1 and 2. Business and Properties" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Adverse weather conditions may negatively affect HighPeak Energy's operating results and ability to conduct drilling activities.

Adverse weather conditions may cause, among other things, increases in the costs of, and delays in, drilling or completing new wells, power failures, temporary shut-in of production and difficulties in the transportation of crude oil, NGL and natural gas. Any decreases in production due to poor weather conditions will have an adverse effect on revenues, which will in turn negatively affect cash flow from operations. Climate change may also increase the frequency or intensity of such adverse weather conditions; for more information, see our risk factor titled "The operations of HighPeak Energy are subject to a variety of risks arising from climate change."

HighPeak Energy's operations are substantially dependent on the availability of frac sand and water. Restrictions on its ability to obtain frac sand and water may have an adverse effect on its financial condition, results of operations and cash flows.

Water and sand are an essential component of crude oil and natural gas production during the hydraulic fracturing process, and to a lesser extent, drilling operations. Drought conditions have persisted in the areas where the Company's assets are located in past years. Such drought conditions can lead governmental authorities to restrict the use of water, subject to their jurisdiction, for hydraulic fracturing to protect local water supplies. Although HighPeak Energy may enter into a long-term contract for the supply of water, it currently procures local water for drilling on a well-to-well basis and currently recycles a significant portion of its produced water for completion operations. If HighPeak Energy is unable to obtain water to use in operations, it may need to be obtained from non-local sources and transported to drilling sites, resulting in increased costs, or HighPeak Energy may be unable to economically produce crude oil and natural gas, which could have a material and adverse effect on its financial condition, results of operations and cash flows.

The Company's assets are located in the northeastern Midland Basin, making HighPeak Energy vulnerable to risks associated with operating in a limited geographic area.

All HighPeak Energy's producing properties are geographically concentrated in the northeastern Midland Basin. As a result, HighPeak Energy may be disproportionately exposed to various factors, including, among others: (i) the impact of regional supply and demand factors, (ii) delays or interruptions of production from wells in such areas caused by governmental regulation, (iii) processing or transportation capacity constraints, (iv) market limitations, (v) availability of equipment and personnel, (vi) water shortages or other drought related conditions or (vii) interruption of the processing or transportation of crude oil, NGL or natural gas. The concentration of the Company's assets in a limited geographic area also increases its exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife and unexpected events that may occur in the regions such as natural disasters, adverse weather, seismic events, industrial accidents or labor difficulties. Any one of these factors has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expirations. Any of the risks described above could have a material adverse effect on HighPeak Energy's business, financial condition, results of operations and cash flow.

HighPeak Energy may incur losses as a result of title defects in the properties in which it invests.

The existence of a material title deficiency can render a lease worthless and adversely affect HighPeak Energy's results of operations and financial condition. While HighPeak Energy typically obtains title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case HighPeak Energy may lose the lease and the right to produce all or a portion of the minerals under the property. Additionally, if an examination of the title history of a property reveals that a crude oil or natural gas lease or other developed right has been purchased in error from a person who is not the owner of the mineral interest desired, HighPeak Energy's interest would substantially decline in value. In such cases, the amount paid for such crude oil or natural gas lease or leases would be lost.

The development of estimated PUDs may take longer and may require higher levels of capital expenditures than anticipated. Therefore, estimated PUDs may not be ultimately developed or produced.

As of December 31, 2023, the Company's assets contained 74,569 MBoe of proved undeveloped reserves, or PUDs, consisting of 60,923 MBbls of crude oil, 7,913 MBbls of NGL and 34,400 MMcf of natural gas. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than anticipated. Estimated future development costs relating to the development of such PUDs at December 31, 2023 are approximately $1.5 billion over the next five (5) years. HighPeak Energy's ability to fund these expenditures is subject to several risks. See "—HighPeak Energy's development projects and acquisitions will require substantial capital expenditures. HighPeak Energy may be unable to obtain required capital or financing on satisfactory terms, which could reduce its ability to access or increase production and reserves." Delays in the development of reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of the estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause HighPeak Energy to have to reclassify PUDs as unproved reserves. Furthermore, there is no certainty that HighPeak Energy will be able to convert PUDs to developed reserves or that undeveloped reserves will be economically viable or technically feasible to produce.

Further, SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement may limit HighPeak Energy's ability to book additional PUDs as it pursues its future drilling programs. As a result, HighPeak Energy may be required to write-down its PUDs if it does not drill those wells within the required timeframe. If actual reserves prove to be less than current reserve estimates, or if HighPeak Energy is required to write-down some of its PUDs, such reductions could have a material adverse effect on HighPeak Energy's financial condition, results of operations and future cash flows.

Unless HighPeak Energy replaces its reserves with new reserves and develops those new reserves, its reserves and production will decline, which would adversely affect future cash flows and results of operations.

Producing crude oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless HighPeak Energy conducts successful ongoing exploration and development activities or continually acquires properties containing proved reserves, proved reserves will decline as those reserves are produced. HighPeak Energy's future reserves and production, and therefore future cash flows and results of operations, are highly dependent on HighPeak Energy's success in efficiently developing current reserves and economically finding or acquiring additional recoverable reserves. HighPeak Energy may not be able to develop, find or acquire sufficient additional reserves to replace future production. If HighPeak Energy is unable to replace such production, the value of its reserves will decrease, and its business, financial condition and results of operations would be materially and adversely affected.

HighPeak Energy depends upon a small number of significant purchasers for the sale of most of its crude oil, NGL and natural gas production. The loss of one or more of such purchasers could, among other factors, limit HighPeak Energy's access to suitable markets for the crude oil, NGL and natural gas it produces.

HighPeak Energy expects to sell its production to a relatively small number of customers, as is customary in the crude oil and natural gas business. For the year ended December 31, 2023, there were two purchasers that accounted for approximately 96% of our revenue (one at approximately 82% and one at approximately 14%) and for the years ended December 31, 2022 and 2021, there was one purchaser that accounted for approximately 88% and 94% of our revenue, respectively. No other purchaser accounted for 10% or more of such revenues during such period. The loss of any such greater than 10% purchaser could adversely affect HighPeak Energy's revenues in the short term. See the section entitled "Items 1 and 2: Business and Properties—Operations—Marketing and Customers" for additional information. HighPeak Energy expects to depend upon these or other significant purchasers for the sale of most of its crude oil and natural gas production. HighPeak Energy cannot ensure that it will continue to have ready access to suitable markets for its future crude oil and natural gas production.

HighPeak Energy's operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to its business activities.

HighPeak Energy's operations will be subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, the occupational health and safety aspects of its operations or otherwise relating to the protection of the environment and natural resources. These laws and regulations may impose numerous obligations applicable to HighPeak Energy's operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from HighPeak Energy's operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all HighPeak Energy's operations. In addition, HighPeak Energy may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt its operations and limit growth and revenue.

Certain environmental laws impose strict liability (i.e., no showing of "fault" is required) as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. HighPeak Energy may be required to remediate contaminated properties owned or operated by it or facilities of third parties that received waste generated by operations regardless of whether such contamination resulted from the conduct of others or from consequences of its own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, HighPeak Energy could acquire, or be required to provide indemnification against, environmental liabilities that could expose HighPeak Energy to material losses. In certain instances, citizen groups also have the ability to bring legal proceedings against HighPeak Energy if it is not in compliance with environmental laws, or to challenge its ability to receive environmental permits needed to operate. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of its operations. HighPeak Energy's insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability.

For example, HighPeak Energy may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of its wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including the following federal laws and their state counterparts, as amended from time to time, among others:

- the CAA, which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring and reporting requirements and is relied upon by the EPA as authority for adopting climate change regulatory initiatives relating to GHG emissions;
- the CWA, which regulates discharges of pollutants from facilities and sources to federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the OPA, which imposes liabilities for removal costs and damages arising from a crude oil spill into waters of the United States;

- the SDWA, which ensures the quality of the nations' public drinking water through adoption of drinking water standards and control over the subsurface injection of fluids into belowground formations;
- the RCRA, which imposes requirements for the generation, treatment, storage, transport, disposal and cleanup of non-hazardous, hazardous and solid wastes;
- CERCLA, which imposes liability on generators, transporters and those who arrange for transportation or disposal of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur, as well as imposes liability on present and certain past owners and operations of sites where hazardous substance releases have occurred or are threatening to occur;
- the ESA, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating limitations or restrictions or a temporary, seasonal or permanent ban on operations in affected areas; and
- OSHA, under which federal Occupational Safety and Health Administration and similar state agencies have promulgated regulations limiting exposures to hazardous substances in the workplace and imposing various worker safety requirements.

Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective actions, the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects and the issuance of orders enjoining some or all HighPeak Energy's future operations in a particular area. It is not uncommon for neighboring landowners, employees and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, wastes or other materials into the environment. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and more stringent laws and regulations may be adopted in the future.

To the extent HighPeak Energy's operations are affected by national, regional, local and other laws, and to the extent such laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, HighPeak Energy's business, prospects, financial condition or results of operations could be materially adversely affected.

HighPeak Energy may incur increasing attention to ESG matters that may impact its business.

Businesses across all industries are facing increasing scrutiny from stakeholders related to their ESG practices. Businesses that do not adapt to or comply with investor or stakeholder expectations and standards, which are evolving, or which are perceived to have not responded appropriately to the growing concern for ESG issues, regardless whether there is a legal requirement to do so, may suffer from reputational damage and the business, financial condition and/or stock price of such business entity could be materially and adversely affected. Increasing attention to climate change, increasing societal expectations on businesses to address climate change, and potential consumer use of substitutes to energy commodities may result in increased costs, reduced demand for HighPeak Energy's hydrocarbon products, reduced profits, increased investigations and litigation and negative impacts on its stock price and access to capital markets. Increasing attention to climate change, for example, may result in demand shifts for HighPeak Energy's hydrocarbon products and additional governmental investigations and private litigation.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, certain statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. We may also announce participation in, or certification under, various third-party ESG frameworks in an attempt to improve our ESG profile, but such participation or certification may be costly and may not achieve the desired results. Additionally, while we may announce various voluntary ESG targets, such targets are aspirational. We may not be able to meet such targets in the manner or on such a timeline as initially contemplated, including but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such results. To the extent we meet such targets, it may be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. Also, despite these aspirational goals and any other actions taken, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

In addition, organizations that provided information to investors on corporate governance and related matters have developed rating processes for evaluating business entities on their approach to ESG matters. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Such ratings are used by some investors to inform their investment and voting decisions. Additionally, certain investors use these scores to benchmark businesses against their peers and if a business entity is perceived as lagging, these investors may engage with such entities to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a business entity's sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of HighPeak Energy's stock from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of HighPeak Energy's operation by certain investors. Additionally, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations. ESG matters may also impact our suppliers and customers, which may ultimately have adverse impacts on our operations.

HighPeak Energy may incur substantial losses and be subject to substantial liability claims as a result of operations. Additionally, HighPeak Energy may not be insured for, or insurance may be inadequate to protect HighPeak Energy against, these risks.

HighPeak Energy will not be insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect its business, financial condition or results of operations.

HighPeak Energy's development activities will be subject to all the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of crude oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination, damage to natural resources or wildlife, or the presence of endangered or threatened species;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting crude oil and natural gas related facilities and infrastructure.

Any of these events could adversely affect HighPeak Energy's ability to conduct operations or result in substantial loss as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental or natural resource damage;
- regulatory investigations and penalties; and
- repair and remediation costs.

HighPeak Energy may elect not to obtain insurance for any or all of these risks if it believes that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on business, financial condition and results of operations.

Properties that HighPeak Energy decides to drill may not yield crude oil or natural gas in commercially viable quantities.

Properties that HighPeak Energy decides to drill that do not yield crude oil or natural gas in commercially viable quantities will adversely affect its results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield crude oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable HighPeak Energy to know conclusively prior to drilling whether crude oil or natural gas will be present or, if present, whether crude oil or natural gas will be present in commercial quantities. HighPeak Energy cannot assure you that the analogies drawn from available data from other wells, more fully explored prospects or producing fields will be applicable to its drilling prospects. Further, HighPeak Energy's drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title issues;
- pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with, or changes in, environmental and other governmental or contractual requirements, including the IRA 2022; and
- increases in the cost of, and shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

HighPeak Energy may be unable to make additional attractive acquisitions or successfully integrate acquired businesses with its current assets, and any inability to do so may disrupt its business and hinder its ability to grow.

HighPeak Energy may not be able to identify attractive acquisition opportunities that complement the Company's assets or expand its business. In the event it identifies attractive acquisition opportunities, HighPeak Energy may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause HighPeak Energy to refrain from, completing acquisitions.

The success of completed acquisitions will depend on HighPeak Energy's ability to integrate effectively the acquired business into its then-existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of its 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 it will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. HighPeak Energy's failure to achieve consolidation savings, to integrate the acquired businesses and assets, including those from the Hannathon and Alamo Acquisitions, into its then-existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on its financial condition and results of operations.

In addition, the Term Loan Credit Agreement and Senior Credit Facility Agreement impose certain limitations on HighPeak Energy's ability to enter into mergers or combination transactions and on HighPeak Energy's and its restricted subsidiaries' ability to incur certain indebtedness, which could indirectly limit its ability to acquire assets and businesses.

Certain of HighPeak Energy's properties are subject to land use restrictions, which could limit the manner in which HighPeak Energy conducts business.

Certain of HighPeak Energy's properties are subject to land use restrictions, which could limit the manner in which HighPeak Energy conducts business. Such restrictions could affect, among other things, access to and the permissible uses of facilities as well as the manner in which HighPeak Energy produces crude oil and natural gas and may restrict or prohibit drilling in general. The costs incurred to comply with such restrictions may be significant, and HighPeak Energy may experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from the drilling of wells.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel, frac crews and oilfield services due to commodity price volatility or supply constraints as a result of the conflict in Ukraine, the Israel-Hamas conflict, elevated interest rates and associated policies of the Federal Reserve could adversely affect HighPeak Energy's ability to execute its development plans within its budget and on a timely basis and consequently could materially and adversely affect our cash flows and results of operations.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the crude oil and natural gas industry, can fluctuate significantly, often in correlation with crude oil, NGL and natural gas prices, causing periodic shortages of equipment, supplies and needed personnel. Additionally, supply constraints due to the conflict in Ukraine, the Israel-Hamas conflict, elevated interest rates and associated policies of the Federal Reserve has increased the cost of oilfield services. HighPeak Energy's operations are concentrated in areas in which oilfield activity levels have previously increased rapidly. If that were to happen again, demand for drilling rigs, equipment, supplies and personnel may increase the costs for these services. Access to transportation, processing and refining facilities in these areas may become constrained resulting in higher costs and reduced access for those items. Historically, crude oil, NGL and natural gas prices have been volatile. For example, during the period from January 1, 2020 through December 31, 2023, the calendar month average NYMEX WTI crude oil price per Bbl ranged from a low of $16.70 to a high of $114.34, and the last trading day NYMEX natural gas price per MMBtu ranged from a low of $1.50 to a high of $9.35. For the month of April 2020, the calendar month average NYMEX WTI crude oil price was $16.70 and last trading day NYMEX natural gas price was $1.63 per MMBtu. However, prices have since increased. To the extent commodity prices improve in the future, the demand for and prices of these goods and services are likely to increase and HighPeak Energy could encounter delays in or an inability to secure the personnel, equipment, power, services, resources and facilities access necessary for it to resume or increase HighPeak Energy's development activities, which could result in production volumes being below its forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on cash flow and profitability. Furthermore, if it is unable to secure a sufficient number of drilling rigs at reasonable costs, HighPeak Energy may not be able to drill all its acreage before its leases expire.

HighPeak Energy could experience periods of higher costs if commodity prices rise and inflation may adversely affect our operating results. These increases in cost could reduce profitability, cash flow and ability to complete development activities as planned.

Historically, capital and operating costs have risen during periods of increasing crude oil, NGL and natural gas prices. Inflationary factors such as increases in the labor costs, material costs and overhead costs may adversely affect our operating results. These cost increases have resulted from a variety of factors that HighPeak Energy will be unable to control, such as increases in the cost of electricity, steel and other raw materials; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in HighPeak Energy's revenue if commodity prices rise, thereby negatively impacting its profitability, cash flow and ability to complete development activities as scheduled and on budget. A high rate of inflation, including a continuation of inflation at the current rate, may have an adverse effect on HighPeak Energy's operating results. This impact may be magnified to the extent that HighPeak Energy's ability to participate in the commodity price increases is limited by its derivative activities, if any.

The IRA 2022 could accelerate the transition to a low carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the IRA 2022 into law. The IRA 2022 contains hundreds of billions in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and carbon capture and sequestration, amongst other provisions. In addition, the IRA 2022 imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge. The IRA 2022 amends the federal Clean Air Act to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA 2022. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives. This could decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently adversely affect our business.

In addition, fuel conservation measures, alternative fuel requirements and increasing consumer demand for alternatives to crude oil, NGL and natural gas could reduce demand for crude oil, NGL and natural gas. The IRA 2022 incentives discussed above could further accelerate the transition of our economy to alternatives to crude oil, NGL and natural gas. The impact of the changing demand for crude oil, NGL and natural gas may have a material adverse effect on our business, financial condition, results of operations and cash flows.

HighPeak Energy may be involved in legal proceedings that could result in substantial liabilities.

Like many crude oil and natural gas companies, HighPeak Energy may be involved from time to time in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of its business. Such proceedings are inherently uncertain, and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on HighPeak Energy because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in its business practices, which could materially and adversely affect its business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Should our operators fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, our operators could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, FERC has civil penalty authority under the Natural Gas Act of 1938 to impose penalties for current violations of up to $1,544,521 per day for each violation (annually adjusted for inflation) and disgorgement of profits associated with any violation. While our operators' operations have not been regulated by the FERC as a natural gas company under this law, the FERC has adopted regulations that may subject certain of our operators' otherwise non-FERC jurisdictional facilities to the FERC annual reporting requirements. Our operators also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1,472,546 per day (annually adjusted for inflation) and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to crude oil swaps and futures contracts as that granted to the CFTC with respect to crude oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1,450,040 per day (annually adjusted for inflation) or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject our operators to civil penalty liability, as described in "Items 1 and 2: Business and Properties—Regulation of the Crude Oil and Natural Gas Industry."

The operations of HighPeak Energy are subject to a variety of risks arising from climate change.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, crude oil and natural gas exploration and production operations are subject to a series of regulatory, political, litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level, though federal law such as the IRA 2022 advances numerous climate-related objectives. However, with the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. The regulation of methane from crude oil and natural gas facilities has been subject to uncertainty in recent years. Although, in September 2020, the Trump Administration revised prior promulgated regulations to rescind certain methane standards and remove the transmission and storage segments from the source category for certain regulations, the U.S. Congress approved, and President Biden signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions, effectively reinstating the prior standards. Additionally, in December 2023, the EPA finalized a rule that established OOOOb as new source and OOOOc as first-time existing source standards of performance for methane and VOC emissions for the crude oil and natural gas source category. Under the final rule, owners or operators of affected emission units or processes will have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards under the final rule are generally the same for both new and existing sources, including enhanced leak detection using optical gas imaging and subsequent repair requirements, reduction of regulated emissions through capture and control systems, zero-emission requirements for certain equipment or processes, operations and maintenance requirements and requirements for "green well" completions. The rule also establishes a "super-emitter" response program to timely mitigate emissions events as detected by governmental agencies or qualified third parties, triggering certain investigation and repair requirements. Separately, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, the United Nations-sponsored "Paris Agreement" requires member states to submit non-binding, individually-determined reduction goals every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at COP26, during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. These goals were reaffirmed at COP27, and countries were called upon to accelerate their efforts, though no firm commitments were made. At COP28, the parties entered into an agreement to transition away from fossil fuels in energy systems and increase renewable energy capacity, though no timeline for doing so was set. The impacts of these actions cannot be predicted at this time. For more information, see the section entitled "Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters— Regulation of Greenhouse Gas Emissions."

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates in public office. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry and increased emphasis on climate-related risks across agencies and economic sectors. Additional actions that could be pursued by the Biden Administration may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities. For example, on January 26, 2024, President Biden announced a temporary pause on pending decisions on new exports of LNG to countries that the U.S. does not have free trade agreements with, pending Department of Energy review. Litigation risks are also increasing, as a number of entities have sought to bring suit against crude oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change or that such companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing and/or underwriting activities to net zero by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. In late 2020, the Federal Reserve announced it has joined the NGFS and, in November 2021, issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. In September 2022, the Federal Reserve announced that six of the U.S.' largest banks will participate in a pilot climate scenario analysis exercise, which took place throughout 2023, to enhance the ability of firms and supervisors to measure and manage climate-related financial risk. Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities. In addition, the SEC proposed a rule requiring registrants to make certain climate-related disclosures, including emissions data. The final rule remains pending, and we cannot predict its final form or substance. To the extent the rules impose additional reporting obligations, we could face increased costs. Some states have also enacted or are considering climate-related disclosure requirements. Additionally, we cannot predict how financial institutions and investors might consider any information disclosed under a final rule when making investment decisions, and as a result it is possible that we could face increases with respect to the costs of, or restrictions imposed on, our access to capital. For more information, see the section entitled "Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters— Regulation of Greenhouse Gas Emissions."

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from crude oil and natural gas producers such as HighPeak Energy or otherwise restrict the areas in which HighPeak Energy may produce crude oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or erode value for, the crude oil and natural gas that HighPeak Energy produces. Additionally, political, litigation and financial risks may result in HighPeak Energy's restricting or cancelling crude oil and natural gas production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on HighPeak Energy's business, financial condition and results of operations.

Finally, many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climate events that could have an adverse effect on HighPeak Energy's operations. If such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship or by reducing demand for fossil fuels we provide, such as to the extent warmer winters reduce the demand for energy for heating purposes. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations. If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserve estimates and potential impairments and associated charges to our earnings.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of crude oil and natural gas wells and adversely affect HighPeak Energy's production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of crude oil and natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. HighPeak Energy expects to regularly use hydraulic fracturing as part of HighPeak Energy's operations. Hydraulic fracturing is typically regulated by state crude oil and natural gas commissions, but certain federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Congress has, from time to time, considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect HighPeak Energy's operations, but such additional federal regulation could have an adverse effect on its business, financial condition and results of operations.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water under certain limited circumstances.

Moreover, some states and local governments have adopted, and other governmental entities are considering adopting, regulations that could impose more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations, including states in which our properties are located. For example, Texas, among others, has adopted regulations that impose new or more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. States could also elect to prohibit high volume hydraulic fracturing altogether. In addition to state laws, local land use restrictions, such as city ordinances may restrict drilling in general and/or hydraulic fracturing in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where HighPeak Energy will operate, it could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells. For more information, see the section entitled "Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters— Hydraulic Fracturing Activities."

Legislation or regulatory initiatives intended to address seismic activity could restrict HighPeak Energy's drilling and production activities, as well as HighPeak Energy's ability to dispose of produced water gathered from such activities, which could have a material adverse effect on its future business.

State and federal regulatory agencies have at times focused on a possible connection between the hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between crude oil and natural gas activity and induced seismicity. For example, in 2015, the United States Geological Study identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or crude oil and natural gas extraction.

In addition, a number of lawsuits have been filed in some states, including Texas, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, Texas has imposed certain limits on the permitting or operation of disposal wells in areas with increased instances of induced seismic events. In some instances, regulators may also order that disposal wells be shut-in. In September 2021, the TRRC issued a notice to operators in the city of Midland area to reduce daily injection volumes following multiple earthquakes above a 3.5 magnitude over an 18-month period. The notice also required disposal well operators to provide injection data to TRRC staff to further analyze seismicity in the area. Subsequently, the TRRC ordered the indefinite suspension of all deep crude oil and natural gas produced water injection wells in the area, effective December 31, 2021. The response area was expanded to cover an additional 17 wells following another earthquake in December 2022. Additional response areas have been established, most recently the Northern Culberson-Reeves Seismic Response Area, where 23 deep disposal well permits were suspended in December 2023.

HighPeak Energy will likely dispose of large volumes of produced water gathered from its drilling and production operations by injecting it into wells pursuant to permits issued by governmental authorities overseeing such disposal activities. While these permits will be issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict HighPeak Energy's ability to use hydraulic fracturing or dispose of produced water gathered from its drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring HighPeak Energy to shut down disposal wells, could have a material adverse effect on its business, financial condition and results of operations.

Competition in the crude oil and natural gas industry is intense, which will make it more difficult for HighPeak Energy to acquire properties, market crude oil or natural gas and secure trained personnel.

HighPeak Energy's ability to acquire additional prospects and to find and develop reserves in the future will depend on its ability to evaluate and select suitable properties for acquisitions and to consummate transactions in a highly competitive environment for acquiring properties, marketing crude oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Many other crude oil and natural gas companies possess and employ greater financial, technical and personnel resources than HighPeak Energy. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than HighPeak Energy's financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than HighPeak Energy will be able to offer. The cost to attract and retain qualified personnel has historically continually increased due to competition and may increase substantially in the future. HighPeak Energy may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on its business.

The loss of senior management or technical personnel could adversely affect operations.

HighPeak Energy will depend on the services of its senior management and technical personnel. HighPeak Energy does not plan to obtain any insurance against the loss of any of these individuals. The loss of the services of its senior management could have a material adverse effect on its business, financial condition and results of operations.

Increases in interest rates could adversely affect HighPeak Energy's business.

HighPeak Energy will require continued access to capital and its business and operating results could be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. HighPeak Energy uses, and expects to continue to use debt financing, including borrowings under the Credit Agreements, to finance a portion of its future growth, and these changes could cause its cost of doing business to increase, limit its ability to pursue acquisition opportunities, reduce cash flow used for drilling and place HighPeak Energy at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting its ability to finance its operations. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect its ability to achieve its planned growth and operating results.

HighPeak Energy's use of seismic data is subject to interpretation and may not accurately identify the presence of crude oil and natural gas, which could adversely affect the results of its drilling operations.

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, HighPeak Energy's drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and it could incur losses as a result of such expenditures.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect HighPeak Energy's ability to conduct drilling activities in areas where it operates.

Crude oil and natural gas operations in HighPeak Energy's operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Such restrictions may limit HighPeak Energy's ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay HighPeak Energy's operations or materially increase its operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species, other protected species (such as migratory birds), or their habitat could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where HighPeak Energy operates as threatened or endangered could cause it to incur increased costs arising from species protection measures or could result in limitations on its activities that could have a material and adverse impact on its ability to develop and produce reserves. For example, a review is currently pending to determine whether the dunes sagebrush lizard should be listed and, in November 2022, the FWS listed two distinct population segments of the lesser prairie-chicken under the ESA. If these species or others are listed, the FWS and similar state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species. Such a designation could materially restrict use of or access to federal, state and private lands. To the extent species are listed under the ESA or similar state laws, or previously unprotected species are designated as threatened or endangered in areas where our properties are located, operations on those properties could incur increased costs arising from species protection measures and face delays or limitations with respect to production activities thereon. For more information, see the section entitled "Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters— Endangered Species Act and Migratory Birds."

HighPeak Energy may not be able to keep pace with technological developments in its industry.

The crude oil and natural gas industry is characterized by rapid and significant technological advancement and the introduction of new products and services using new technologies. As others use or develop new technologies, HighPeak Energy may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other crude oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may, in the future, allow them to implement new technologies before HighPeak Energy. HighPeak Energy may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies it expects to use were to become obsolete, HighPeak Energy's business, financial condition or results of operations could be materially and adversely affected.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm HighPeak Energy's business may occur and not be detected.

HighPeak Energy's management does not expect that HighPeak Energy's internal and disclosure controls will prevent all possible error 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, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, at HighPeak Energy 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 error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is 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 its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

HighPeak Energy's business could be adversely affected by security threats, including cyber-security threats, and related disruptions.

HighPeak Energy relies heavily on its information systems, and the availability and integrity of these systems is essential to conducting HighPeak Energy's business and operations. As a producer of crude oil and natural gas, HighPeak Energy faces various security threats, including cyber-security threats, to gain unauthorized access to its sensitive information or to render its information or systems unusable, and threats to the security of its facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing and other facilities, refineries and pipelines. This risk may be heightened as a result of an increased remote working environment, similar to the one created by the COVID-19 outbreak in 2020. The potential for such security threats subjects its operations to increased risks that could have a material adverse effect on its business, financial condition, results of operations and cash flows.

Cyber-security attacks in particular are becoming more sophisticated and include, but are not limited to, installation of malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. For example, in May 2021, Colonial Pipeline's digital systems were infected by a ransomware attack that caused the shutdown of the pipeline for several days and the payment of an approximate $4.4 million ransom. The U.S. government also has issued public warnings that indicate that energy assets might be specific targets of cybersecurity threats. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of personal or confidential information pose increasingly complex compliance challenges and could potentially elevate our costs. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. We continue to monitor and assess the impact of these laws, which in addition to penalties and legal liability, could impose significant costs for investigations and compliance, require us to change our business practices and carry significant potential liability for our business should we fail to comply with any such applicable laws.

HighPeak Energy's implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for its information, systems, facilities and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to its business and operations, as well as data corruption, communication interruptions or other disruptions to its operations, which, in turn, could have a material adverse effect on its business, financial position, results of operations and cash flows.

Risks Related to Ownership of our Securities

We are evaluating strategic alternatives, including a possible sale of our business, and there can be no assurance that we will be successful in identifying or completing any strategic alternative transactions, that any such strategic alternative transactions will result in additional value for our shareholders or that the process will not have an adverse impact on our business and shareholders.

Our Board continues to evaluate a range of strategic alternative transactions to maximize shareholder value, including a potential sale of the Company. These transactions could include, but are not limited to, acquisitions, debt refinancing transactions, asset divestitures, monetization of intellectual property, and mergers, reverse mergers or other business combinations. Because we have publicly approved the undertaking of this process, the market price of our common stock may reflect an expectation that shares of our common stock may be acquired at a premium in the near future.

There can be no assurance that the review of strategic alternative transactions will result in the identification or consummation of any transaction. Our Board may also determine that our most effective strategy is to continue to effectuate our current business plan. The process of reviewing strategic alternative transactions may be time consuming and disruptive to our business operations and, if we are unable to effectively manage the process, our business, financial condition and results of operations could be adversely affected. We could incur substantial expenses associated with identifying and evaluating potential strategic alternative transactions. No decision has been made with respect to any transaction and we cannot assure you that we will be able to identify and undertake any transaction that allows our shareholders to realize an increase in the value of their common stock or provide any guidance on the timing of such action, if any.

We also cannot assure you that any potential transaction or other strategic alternatives, if identified, evaluated and consummated, will provide greater value to our shareholders than that reflected in the current price of our common stock. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, but not limited to, market conditions, industry trends, the interest of third parties in our business and the availability of financing to potential buyers on reasonable terms. We do not intend to comment regarding the evaluation of strategic alternative transactions until such time as our Board has determined the outcome of the process or otherwise has deemed that disclosure is appropriate or required by applicable law. As a consequence, perceived uncertainties related to our future may result in the loss of potential business opportunities and volatility in the market price of our common stock and may make it more difficult for us to attract and retain qualified personnel and business partners.

HighPeak Energy may not be able to pay dividends on our common stock.

Our Board of Directors may elect to declare cash dividends on our common stock, subject to our compliance with applicable law and the Credit Agreements. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board of Directors, and we have no obligation to pay any dividends at any time. Our Board of Director's determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the Board of Directors deems relevant at the time of such determination.

The Principal Stockholder Group has significant influence over HighPeak Energy.

The Principal Stockholder Group owns approximately 67% of HighPeak Energy's common stock as of December 31, 2023. This includes an aggregate of approximately one million shares of common stock purchased by the Principal Stockholder Group in connection with the Company's underwritten equity offering in July 2023, which further increased the Principal Stockholder Group's ownership in the Company. As long as the Principal Stockholder Group owns or controls a significant percentage of HighPeak Energy's outstanding voting power, subject to the terms of the Stockholders' Agreement (as defined below), they will have the ability to influence certain corporate actions requiring stockholder approval. Under the Stockholders' Agreement, the Principal Stockholder Group will be entitled to nominate a specified number of directors for appointment to the Board so long as the Principal Stockholder Group meets certain ownership criteria outlined in the Stockholders' Agreement. For more information about the Stockholders' Agreement, see the section entitled "Certain Relationships and Related Transactions, and Director Independence."

If HighPeak Energy's operational and financial performance does not meet the expectations of investors, stockholders or financial analysts, the market price of our securities may decline.

If HighPeak Energy's operational and financial performance does not meet the expectations of investors or securities analysts, the market price of our securities may decline. The market values of our securities may vary significantly from time to time.

In addition, fluctuations in the price of our securities could contribute to the loss of all or part of your investment. The trading price of our securities could be volatile and subject to wide fluctuations in response to various factors, some of which are beyond our control. Any of the factors listed below could have a material adverse effect on your investment in our securities and our securities may trade at prices significantly below the price you paid for them. In such circumstances, the trading price of our securities may not recover and may experience a further decline.

Factors affecting the trading price of our securities may include:

- actual or anticipated fluctuations in our financial results or the financial results of companies perceived to be similar to us;
- changes in the market's expectations about our operating results;
- success of our competitors;
- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or the market in general;
- operating and stock price performance of other companies that investors deem comparable to us;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of shares of HighPeak Energy common stock available for public sale;
- any major change in our Board or management;

- sales of substantial amounts of HighPeak Energy common stock by the Principal Stockholder Group, our directors, executive officers or significant stockholders, or the perception that such sales could occur; and
- general economic and political conditions such as recessions, interest rates, fuel prices, international currency fluctuations, OPEC+'s ability to continue to agree to limit production among its members and acts of war or terrorism.

HighPeak Energy is a "controlled company" within the meaning of Nasdaq rules and qualifies for exemptions from certain corporate governance requirements. As a result, you do not have the same protections afforded to stockholders of companies that are not exempt from such corporate governance requirements.

The Principal Stockholder Group collectively owns a majority of HighPeak Energy's outstanding voting stock. Therefore, HighPeak Energy is a controlled company within the meaning of Nasdaq corporate governance standards. Under Nasdaq rules, a company of which more than 50% of the voting power is held by an individual, company or group of persons acting together is a controlled company and may elect not to comply with certain Nasdaq corporate governance requirements, including the requirements that:

- a majority of the Board consist of independent directors under Nasdaq rules;
- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

HighPeak Energy has elected to rely on all of the exemptions for controlled companies provided for under the Nasdaq rules. These requirements will not apply to HighPeak Energy as long as it remains a controlled company.

HighPeak Energy may be required to take write-downs or write-offs, restructuring and impairment or other charges that could have a significant negative effect on HighPeak Energy's financial condition, results of operations and stock price, which could cause you to lose some or all of your investment.

Although HighPeak Energy conducted due diligence on the Company's assets in connection with their acquisitions, HighPeak Energy cannot assure you that this diligence revealed all material issues that may be present in the businesses of the Company's assets, that it would be possible to uncover all material issues through a customary amount of due diligence, or that factors outside of HighPeak Energy's control will not later arise. As a result, HighPeak Energy may be forced to later write-down or write-off assets, restructure HighPeak Energy's operations, or incur impairment or other charges that could result in losses. Even if HighPeak Energy's due diligence successfully identifies certain risks, unexpected risks may arise, and previously known risks may materialize in a manner not consistent with HighPeak Energy's preliminary risk analysis. Even though these charges may be non-cash items and may not have an immediate impact on HighPeak Energy's liquidity, the fact that HighPeak Energy reports charges of this nature could contribute to negative market perceptions about HighPeak Energy's securities. In addition, charges of this nature may cause HighPeak Energy to be unable to obtain future financing on favorable terms or at all.

There is no guarantee that our warrants will be in the money at the time you choose to exercise them, and they may expire worthless.

The exercise price for our warrants is $11.50 per share of HighPeak Energy common stock, subject to certain adjustments. There is no guarantee that our warrants will be in the money at the time you choose to exercise them, and as such, our warrants may expire worthless.

The terms of our warrants may be amended in a manner that may be adverse to holders of our warrants with the approval by the holders of at least 50% of our then-outstanding warrants.

Our warrants were issued in registered form under the Warrant Agreement Amendment. The Warrant Agreement Amendment provides that the terms of the warrants may be amended without the consent of any holder to cure any ambiguity or correct or supplement any defective provision but requires the approval by the holders of at least 50% of the then-outstanding warrants to make any other change or modification, including any amendment that adversely affects the interests of the registered holders of our warrants. Accordingly, HighPeak Energy, may amend the terms of its warrants in a manner adverse to a holder if holders of at least 50% of the then-outstanding warrants approve of such amendment. Although HighPeak Energy's ability to amend the terms of its warrants with the consent of at least 50% of the then-outstanding warrants is unlimited and such amendments could, among other things, increase the exercise price of the warrants, shorten the exercise period or decrease the number of shares of HighPeak Energy common stock purchasable upon exercise of a warrant.

Warrants are exercisable for HighPeak Energy common stock and HighPeak Energy's LTIP provides for a significant number of stock options, each of which could increase the number of shares eligible for future resale in the public market and result in dilution to stockholders.

The potential for the issuance of a substantial number of additional shares of HighPeak Energy common stock upon exercise of its warrants would increase the number of issued and outstanding shares of HighPeak Energy common stock and reduce the value of the shares issued and outstanding as of the date hereof. Additionally, the sale, or even the possibility of sale, of the shares underlying the warrants could have an adverse effect on the market price for HighPeak Energy's common stock or on its ability to obtain future financing. If and to the extent these warrants are exercised, you may experience dilution to your holdings.

In addition, to attract and retain key management personnel and non-employee directors, HighPeak Energy has implemented a Long-Term Incentive Plan ("LTIP"), pursuant to which the Share Pool (as defined in the LTIP) is reserved and available for delivery with respect to Stock Awards (as defined in the LTIP). From time to time and prior to the expiration of the LTIP, the Share Pool will automatically be increased by (i) the number of shares of HighPeak Energy common stock issued pursuant to the LTIP and (ii) 13% of the number of shares of HighPeak Energy common stock that are newly issued by HighPeak Energy (other than those issued pursuant to the LTIP), including any shares issued upon the exercise of the warrants. As a result, HighPeak Energy could issue a significant number of stock options under the LTIP, including additional shares added to the LTIP upon the exercise of the warrants, which could further dilute your holdings.

If securities or industry analysts do not publish or cease publishing research or reports about HighPeak Energy, HighPeak Energy's business or HighPeak Energy's market, or if they change their recommendations regarding HighPeak Energy common stock adversely, the price and trading volume of HighPeak Energy common stock could decline.

The trading market for HighPeak Energy common stock will be influenced by the research and reports that industry or securities analysts may publish about HighPeak Energy, HighPeak Energy's business, HighPeak Energy's market, or HighPeak Energy's competitors. If any of the analysts who may cover HighPeak Energy change their recommendation regarding HighPeak Energy common stock adversely, or provide more favorable relative recommendations about its competitors, the price of HighPeak Energy common stock would likely decline. If any analyst who may cover HighPeak Energy were to cease their coverage or fail to regularly publish reports on HighPeak Energy, HighPeak Energy could lose visibility in the financial markets, which could cause HighPeak Energy's stock price or trading volume to decline.

The Second Amended and Restated Certificate of Incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or employees.

The Second Amended and Restated Certificate of Incorporation ("A&R Charter") provides that, unless HighPeak Energy consents in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware ("Court of Chancery") will, to the fullest extent permitted by applicable law and subject to applicable jurisdictional requirements, be the sole and exclusive forum for (i) any derivative action or proceeding as to which the Delaware General Corporation Law ("DGCL") confers jurisdiction upon the Court of Chancery, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of HighPeak Energy to HighPeak Energy or its stockholders, (iii) any action asserting a claim against HighPeak Energy, its directors, officers or employees arising pursuant to any provision of the DGCL, the A&R Charter or HighPeak Energy's bylaws or (iv) any action asserting a claim against HighPeak Energy, its directors, officers or employees that is governed by the internal affairs doctrine, in each case except for such claims as to which (a) the Court of Chancery determines that it does not have personal jurisdiction over an indispensable party, (b) exclusive jurisdiction is vested in a court or forum other than the Court of Chancery or (c) the Court of Chancery does not have subject matter jurisdiction. The forum selection provision is not intended to apply to claims arising under the Securities Act or the Exchange Act. To the extent the provision could be construed to apply to such claims, there is uncertainty as to whether a court would enforce such provision in connection with such claims. Stockholders will not be deemed, by operation of Article 8 of the A&R Charter alone, to have waived claims arising under the federal securities laws and the rules and regulations promulgated thereunder.

If any action the subject matter of which is within the scope of the forum selection provision described in the preceding paragraph is filed in a court other than the Court of Chancery (or, if the Court of Chancery does not have jurisdiction, another state court or a federal court located within the State of Delaware) (a "Foreign Action") in the name of any stockholder, such stockholder shall be deemed to have consented to (i) the personal jurisdiction of the state and federal courts located within the State of Delaware in connection with any action brought in any such court to enforce the forum selection provision (a "Foreign Enforcement Action") and (ii) having service of process made upon such stockholder in any such Foreign Enforcement Action by service upon such stockholder's counsel in the Foreign Action as agent for such stockholder.

Any person or entity purchasing or otherwise acquiring any interest in shares of HighPeak Energy's capital stock will be deemed to have notice of, and consented to, the provisions of our A&R Charter described in the preceding paragraph. This exclusive forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with HighPeak Energy or its directors, officers or other employees, which may discourage such lawsuits against HighPeak Energy and such persons. The enforceability of similar exclusive forum provisions in other companies' certificates of incorporation has been challenged in legal proceedings, and it is possible that, in connection with one or more actions or proceedings described above, a court could rule that this provision in the A&R Charter is inapplicable or unenforceable. If a court were to find these provisions of the A&R Charter inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, HighPeak Energy may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect its business, financial condition or results of operations.

Changes in laws or regulations, or a failure to comply with any laws or regulations, may adversely affect HighPeak Energy's business, investments and results of operations.

HighPeak Energy is subject to laws, regulations and rules enacted by national, regional and local governments and the Nasdaq. In particular, HighPeak Energy is required to comply with certain SEC, Nasdaq and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on HighPeak Energy's business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on HighPeak Energy's business and results of operations.

There can be no assurance that HighPeak Energy common stock issued, including issuable upon exercise of our warrants, will remain listed on the Nasdaq, or that HighPeak Energy will be able to comply with the continued listing standards of the Nasdaq.

HighPeak Energy's common stock and warrants are currently listed on the Nasdaq, which such listings includes its common stock or shares of its common stock issuable upon exercise of its warrants. If the Nasdaq delists HighPeak Energy's common stock from trading on its exchange for failure to meet the listing standards, HighPeak Energy and its security holders could face significant material adverse consequences, such as:

- a limited availability of market quotations for HighPeak Energy's securities;
- reduced liquidity for HighPeak Energy's securities;
- a determination that HighPeak Energy common stock is a "penny stock," which will require brokers trading in HighPeak Energy common stock to adhere to more stringent rules and possibly result in a reduced level of trading activity in the secondary trading market for HighPeak Energy's securities;
- a limited amount of news and analyst coverage; and
- a decreased ability to issue additional securities or obtain additional financing in the future.

The National Securities Markets Improvement Act of 1996, which is a federal statute, prevents or preempts the states from regulating the sale of certain securities, which are referred to as "covered securities." Because HighPeak Energy's securities are listed on the Nasdaq, they are covered securities. Although the states are preempted from regulating the sale of HighPeak Energy's securities, the federal statute does allow the states to investigate companies if there is a suspicion of fraud, and, if there is a finding of fraudulent activity, then the states can regulate or bar the sale of covered securities in a particular case. Further, if HighPeak Energy were no longer listed on the Nasdaq, its securities would not be covered securities and HighPeak Energy would be subject to regulation in each state in which HighPeak Energy offers its securities.

Unanticipated changes in effective tax rates or laws or adverse outcomes resulting from examination of HighPeak Energy's income or other tax returns could adversely affect HighPeak Energy's financial condition, results of operations and cash flow.

HighPeak Energy is subject to tax by U.S. federal, state and local tax authorities. HighPeak Energy's future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of HighPeak Energy's deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- tax effects of stock-based compensation;
- costs related to intercompany restructurings; or
- changes in tax laws, regulations or interpretations thereof.

For example, in previous years, legislation has been proposed to eliminate or defer certain key U.S. federal income tax deductions historically available to crude oil and natural gas exploration and production companies. Such proposed changes have included: (i) a repeal of the percentage depletion allowance for crude oil and natural gas properties; (ii) the elimination of deductions for intangible drilling and exploration and development costs; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. The passage of any legislation as a result of these proposals or other similar changes in U.S. federal income tax laws that alter, eliminate or defer these or other tax deductions utilized within the industry could adversely affect HighPeak Energy's business, financial condition, results of operations and cash flows.

In addition, HighPeak Energy may be subject to audits of its income, sales and other transaction taxes by U.S. federal, state and local taxing authorities. Outcomes from these audits could have an adverse effect on HighPeak Energy's financial condition and results of operations.

HighPeak Energy is an emerging growth company within the meaning of the Securities Act, and if HighPeak Energy takes advantage of certain exemptions from disclosure requirements available to emerging growth companies, which could make HighPeak Energy's common stock less attractive to investors and may make it more difficult to compare its performance with other public companies.

HighPeak Energy is an "emerging growth company" within the meaning of the Securities Act, as modified by the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"), and HighPeak Energy takes advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002, reduced disclosure obligations regarding executive compensation in HighPeak Energy's periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. As a result, HighPeak Energy's stockholders may not have access to certain information they may deem important. HighPeak Energy could be an emerging growth company for up to five years (i.e., until December 31, 2025), although circumstances could cause HighPeak Energy to lose that status earlier, including if the market value of HighPeak Energy's equity held by non-affiliates exceeds $700 million as of any June 30 before that time, in which case HighPeak Energy would no longer be an emerging growth company as of the following December 31. HighPeak Energy cannot predict whether investors will find its securities less attractive because HighPeak Energy will rely on these exemptions. If some investors find HighPeak Energy's common stock less attractive as a result of HighPeak Energy's reliance on these exemptions, the trading prices of HighPeak Energy's common stock may be lower than they otherwise would be, there may be a less active trading market for HighPeak Energy's common stock and the trading prices of HighPeak Energy's common stock may be more volatile.

Further, Section 102(b)(1) of the JOBS Act exempts emerging growth companies from being required to comply with new or revised financial accounting standards until private companies (that is, those that have not had a Securities Act registration statement declared effective or do not have a class of securities registered under the Exchange Act) are required to comply with the new or revised financial accounting standards. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies but any such election to opt out is irrevocable. HighPeak Energy has elected not to opt out of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, HighPeak Energy, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of HighPeak Energy's financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accounting standards used.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Overview

HighPeak Energy maintains a cybersecurity program that aims to protect the confidentiality, integrity, and availability of data required by our business to be stored, analyzed, transported, and/or processed. The Company has implemented various internal and external controls and processes, including internal risk assessment and policy implementation, to incorporate a risk-based cybersecurity framework to monitor and mitigate security threats and other strategies to increase security for our information, facilities, and infrastructure.

Risk Management and Strategy

The Company recognizes the risk that cybersecurity threats pose to our operations, and cybersecurity is an important component of our overall risk management strategy. HighPeak Energy's cybersecurity team consists of certain of our executive officers as well as internal and third-party cybersecurity personnel. The cybersecurity team, led by professionals with cybersecurity expertise across multiple industries, takes a cross-functional approach to addressing these risks and engages in discussions with the Board and our executive management team on an as-needed basis.

We have implemented a monitoring and detection system to help promptly identify cybersecurity incidents. We also require our employees and contractors to receive annual cybersecurity awareness training. We perform cybersecurity tabletop exercises to test the effectiveness of our incidence response plan ("IRP") and implement post-incident "lessons learned" to enhance our response. We provide our system users with access consistent with the principle of least privilege, which requires that such users be given no more access than necessary to complete their job functions. We have also implemented a multi-factor authentication process for employees accessing company information. We use encryption methods to protect sensitive data. This includes the encryption of our customer data, financial information, and other confidential data. We have programs in place to monitor our retained data with the goal of identifying personal identifiable information and taking appropriate actions to secure the data.

Third parties also play a role in the Company's approach to cybersecurity and its associated risk management framework. HighPeak Energy leverages technological tools and partners with the goal of augmenting and enabling the efforts of its internal cybersecurity team. Separately, management and oversight of the risks from cybersecurity threats associated with our engagement of third-party service providers is included in our internal auditing processes. In connection with and pursuant to the IRP, our incident response team, made up of management, employees and third-party cybersecurity personnel, works collaboratively across HighPeak Energy to carry out a program that has been designed to protect our information system from cybersecurity threats, assess and manage risks arising from any such threats, and to respond to potential cybersecurity incidents.

We have an IRP that delineates the procedures to be followed for handling a variety of cybersecurity incidents; categorizes potential cybersecurity incidents and the required timeframe for reporting each; establishes cybersecurity incident response levels; provides for investigations designed to help us to meet applicable legal obligations, including possible notification requirements; and outlines the roles and responsibilities for various personnel in the event of a cybersecurity incident.

Governance

The Board, in coordination with the Audit Committee, is responsible for the oversight of risks from cybersecurity threats. The responsibilities of the Audit Committee include overseeing policies and management systems for cybersecurity matters and reviewing HighPeak Energy's strategy, objectives, and policies relative to cybersecurity. In addition, the Board and the Audit Committee receive regular presentations and reports on cybersecurity risks that address a range of topics, including developments, technological trends or tools, third party updates, and regulatory standards. The HighPeak Energy IRP calls for prompt and timely direct notifications and updates to the Board (or its committees) as necessary in connection with cybersecurity incidents deemed to have a moderate or higher business impact, even if immaterial. On a periodic basis, the Board and the Audit Committee discuss our approach to cybersecurity with our executive officers and cybersecurity personnel.

Management plays a role in assessing and managing our material risks from cybersecurity threats through membership on our cybersecurity team, as well as by making final materiality determinations and disclosures and other compliance decisions, as reflected in the HighPeak Energy IRP.

Impact of Risks from Cybersecurity Threats

As of the date of this Report, though the Company and our service providers have experienced certain cybersecurity incidents, we are not aware of any previous cybersecurity threats that have materially affected, or are reasonably likely to materially affect, the Company, including our business strategy, results of operations or financial condition. Notwithstanding the approach we take to cybersecurity, we may not be successful in preventing or mitigating a cybersecurity incident that could have a material adverse effect on us.

For more information on our cybersecurity related risks, see "Item 1A. Risk Factors" for additional information.

ITEM 3. LEGAL PROCEEDINGS

The Company may be a party to various proceedings and claims incidental to its business from time to time. While many of these matters involve inherent uncertainty, the Company believes the amount of the liability, if any, ultimately incurred with respect to these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. See "Item 8. Financial Statements and Supplementary Data – Note 10" for additional information.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

HighPeak Energy's common stock and warrants are listed and traded on the Nasdaq under the symbols "HPK" and "HPKEW," respectively.

Holders

As of February 29, 2024, there were 41 holders of record of HighPeak Energy common stock and 5 holders of record of HighPeak Energy's warrants.

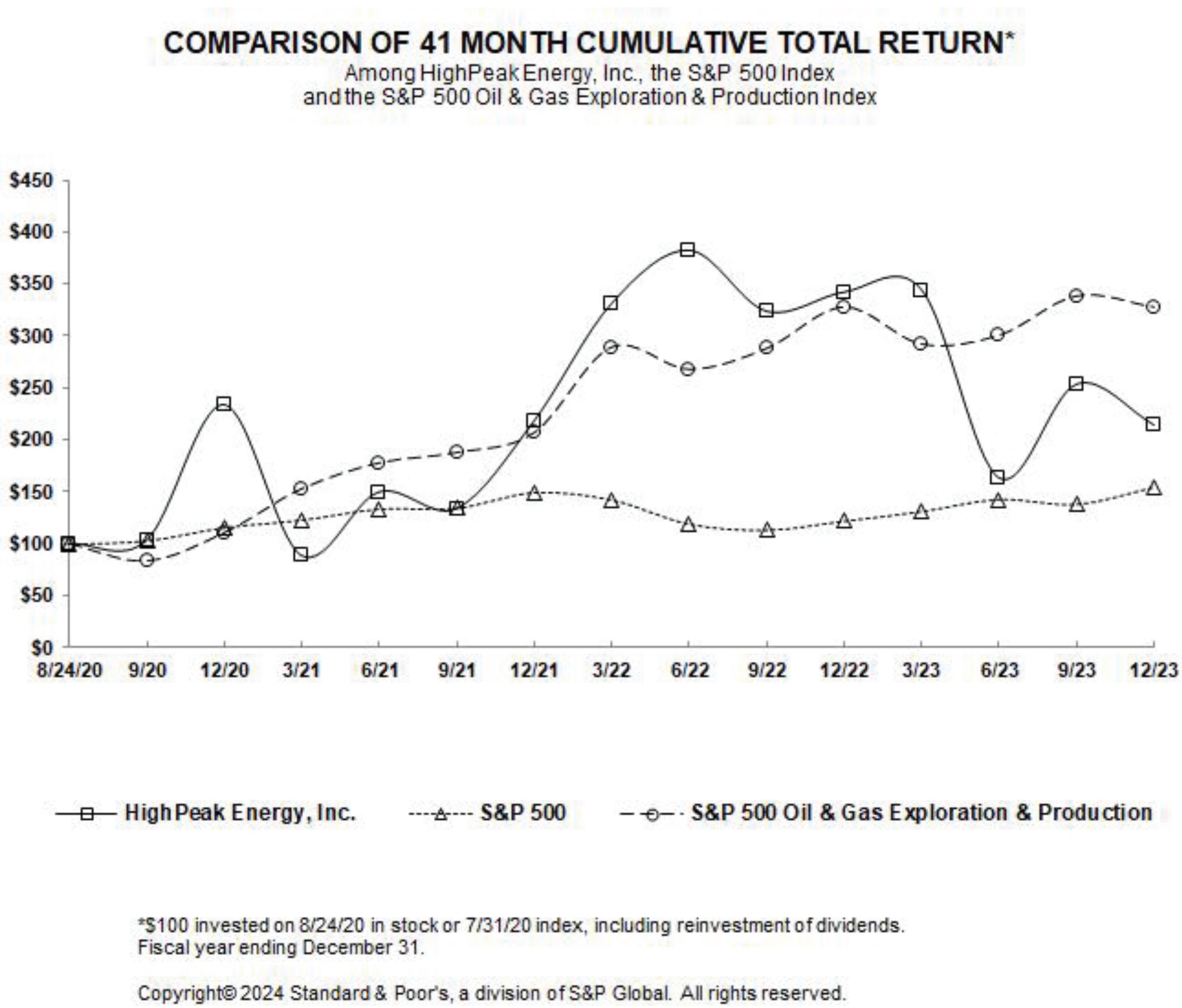
Dividend Policy

On July 6, 2021, the Company announced the initiation of a quarterly cash dividend in the amount of $0.025 per share of our common stock payable quarterly which began with the third quarter of 2021 and continued quarterly through the fourth quarter of 2023. The Company also approved a special dividend of $0.075 per share of common stock that was paid in July 2021. During the first quarter of 2024, the Company announced an increase in its quarterly cash dividends to $0.04 per share of our common stock. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board. Our Board's determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the Board deems relevant at the time of such determination. In addition, the Term Loan Credit Agreement and the Senior Credit Facility Agreement place certain restrictions on our ability to pay cash dividends.

Stock Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall the information be incorporated by reference into any future filing under the Securities Act or Exchange Act except to the extent that the Company specifically incorporate it be reference to such filing.

The graph below compares the cumulative total stockholder return on the Company's common stock during the period from August 24, 2020 through December 31, 2023, with cumulative total returns during the same period for the Standard & Poor's ("S&P") 500 Index and the S&P Oil and Gas Exploration & Production Index.



The stock price performance included in this graph is not necessarily indicative of future stock price performance.

ITEM 6. RESERVED

<u>ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS</u>

The following discussion and analysis should be read in conjunction with the other sections of this Annual Report, including but not limited to "Items 1 and 2. Business and Properties—Regulation of the Crude Oil and Natural Gas Industry." Historical financial statements and related notes included elsewhere in this Annual Report. This discussion contains "forward-looking statements" reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. Factors that could cause or contribute to such differences include, but are not limited to, market prices for crude oil and natural gas, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report. Please read Cautionary Statement Concerning Forward-Looking Statements. Also, please read the risk factors and other cautionary statements described under "Part I, Item 1A. Risk Factors." We assume no obligation to update any of these forward-looking statements, except as required by applicable law. See the Company's Annual Report on Form 10-K for the year ended December 31, 2022 filed with the SEC on March 6, 2023 for a discussion of the Company's 2022 results of operations compared with the Company's 2021 results of operations.

Overview

HighPeak Energy, Inc., a Delaware corporation, was formed in October 2019, is an independent crude oil and natural gas exploration and production company that explores for, develops and produces crude oil, NGL and natural gas in the Permian Basin in West Texas, more specifically, the Midland Basin. The Company's assets are located primarily in Howard and Borden Counties, Texas, and to a lesser extent Scurry and Mitchell Counties, which lie within the northeastern part of the crude oil-rich Midland Basin. As of December 31, 2023, the assets consisted of two highly contiguous leasehold positions of approximately 143,187 gross (131,636 net) acres, approximately 64% of which were held by production, with an average working interest of 92%. Our acreage is composed of two core areas, Flat Top primarily in the northern portion of Howard County extending into southern Borden County, southwest Scurry County and northwest Mitchell County and Signal Peak in the southern portion of Howard County. We operate approximately 98% of the net acreage across the Company's assets and more than 90% of the net operated acreage provides for horizontal wells with lateral lengths of 10,000 feet or greater. For the year ended December 31, 2023, approximately 93% and 7% of sales volumes from the assets were attributable to liquids (both crude oil and NGL) and natural gas, respectively. As of December 31, 2023, HighPeak Energy was developing its properties using three (3) drilling rigs and one (1) frac crew and expects to average two (2) drilling rigs and one (1) frac crew during 2024 under our current development plan.

The markets for the commodities produced by our industry strengthened in 2021 and continued to remain strong through 2023 and into 2024, although the market has decreased from 2022 levels overall, as a result of increased demand outpacing increased supply for each of the commodities we produce. Prices for the commodities produced by our industry improved from historic lows in 2020, with crude oil and natural gas prices reaching their highest average annual price since 2014 in 2022 before cooling off slightly in 2023. However, commodity markets, unavailability or high cost of drilling rigs, equipment, supplies, personnel, frac crews and oilfield services or supply constraints remain subject to heightened levels of uncertainty as a result of the war in Ukraine, the conflict between Israel and Hamas, elevated interest rates and associated policies of the Federal Reserve, which could adversely affect HighPeak Energy's ability to execute on its capital plan. Despite continuing impacts of these and other factors and future uncertainty, we expect to maintain our ability to sustain strong operational performance and financial stability while maximizing returns, improving leverage metrics, and increasing the value of our Midland Basin assets. Additionally, the impact of inflation as well as elevated interest rates continue to have a negative impact on our cash flows and results of operations.

Recent Events

Share Repurchase Program. In February 2024, the Board approved a repurchase program of up to $75 million of the Company's common stock. The approval grants HighPeak's management the authority to repurchase shares opportunistically in the open market from time to time, through block trades, in privately negotiated transactions or by such other means which comply with applicable state and federal laws. This is the Company's first authorization for a stock repurchase program since its founding.

The Company intends to fund the repurchases from available working capital, cash provided from operations and borrowings under its Senior Credit Facility Agreement. The timing, number and value of shares repurchased under the program will be at the discretion of management and the Board of Directors and will depend on a number of factors, including general market and economic conditions, business conditions, the trading price of the Company's common stock, the nature of other investment opportunities available to the Company and compliance with the Company's debt and other agreements. The stock repurchase program does not obligate HighPeak to acquire any particular dollar amount or number of shares of its common stock and the stock repurchase program may be suspended from time to time, modified, extended or discontinued by the Company's Board of Directors. The stock repurchase program authority will expire December 31, 2024.

Debt Refinancing. In September 2023, we completed a refinancing of our long-term debt in its entirety by entering into an agreement with Texas Capital Bank (“Texas Capital”) as the administrative agent and Chambers Energy Management, LP (“Chambers”) as collateral agent and lenders from time-to-time party thereto to establish a term loan (“Term Loan Credit Agreement”) totaling $1.2 billion in borrowings, less a 2.5% original issue discount of $30.0 million at closing and customary debt issuance costs which totaled approximately $24.0 million. The Term Loan Credit Agreement matures on September 30, 2026. Loans under the Term Loan Credit Agreement bear interest at a rate per annum equal to the Adjusted Term SOFR (as defined in the Term Loan Credit Agreement) plus an applicable margin of 7.50%. To the extent that a payment default exists and is continuing, at the election of the Required Lenders (as defined in the Term Loan Credit Agreement) under the Term Loan Credit Agreement, all amounts outstanding under the Term Loan Credit Agreement will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto. The Company is able to repay any amounts borrowed prior to the maturity date, subject to a concurrent payment of (i) the Make-Whole Amount (as defined in the Term Loan Credit Agreement) for any optional prepayment prior to the date 18 months after the closing date, (ii) 1.00% of the principal amount being repaid for any optional prepayment on or after the date 18 months after the closing date but prior to the date 24 months after the closing date and (iii) without any premium for any optional prepayment on or after the date that is 24 months after the closing date. The Term Loan Credit Agreement is guaranteed by the Company and certain of its subsidiaries and is secured by a first lien security interest in substantially all assets of the Company and certain of its subsidiaries.

The Term Loan Credit Agreement also contains certain financial covenants, including (i) an asset coverage ratio that may not be less than 1.50 to 1.00 as of the last day of any fiscal quarter and (ii) a total net leverage ratio that may not exceed 2.00 to 1.00 as of the last day of any fiscal quarter. Additionally, the Term Loan Credit Agreement contains additional restrictive covenants that limit the ability of the Company and its restricted subsidiaries to, among other things, incur additional indebtedness (with such exceptions including, among other things, a super priority revolving credit facility limited to $100 million), incur additional liens, make investments and loans, enter into mergers and acquisitions, materially increase dividends and other payments, enter into certain hedging transactions, sell assets, engage in transactions with affiliates and make certain capital expenditures based on the Company's total net leverage ratio.

The Term Loan Credit Agreement contains customary mandatory prepayments, including quarterly installments of $30.0 million in aggregate principal amount beginning March 31, 2024, the prepayment of gross proceeds from an incurred indebtedness other than Permitted Indebtedness (as defined in the Term Loan Credit Agreement), the prepayment of net cash proceeds for asset sales and hedge terminations in excess of $20.0 million within one calendar year, and prepayments of Excess Cash Flow (as defined in the Term Loan Credit Agreement) beginning with the fiscal quarter ending March 31, 2024. In addition, the Term Loan Credit Agreement is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the collateral agent or the majority lenders may accelerate any amounts outstanding and terminate lender commitments.

Simultaneously with the closing of the Term Loan Credit Agreement, the Company entered into a collateral agency agreement (the "Collateral Agency Agreement") among the Company, Texas Capital, as collateral agent, Chambers, as term representative, and Mercuria Energy Trading SA as first-out representative prior to giving effect to that certain Collateral Agency Joinder – Additional First-Out Debt, dated as of November 1, 2023 and Fifth Third Bank, National Association as first-out representative after giving effect to that certain Collateral Agency Joinder – Additional First-Out Debt, dated as of November 1, 2023.

The Collateral Agency Agreement provides for the appointment of Texas Capital, as collateral agent, for the present and future holders of the first lien obligations (including the obligations of the Company and certain of its subsidiaries under the Term Loan Credit Agreement) to receive, hold, administer and distribute the collateral that is at any time delivered to Texas Capital or the subject of the Security Documents (as defined in the Collateral Agency Agreement) and to enforce the Security Documents and all interests, rights, powers and remedies of Texas Capital with respect thereto or thereunder and the proceeds thereof.

On November 1, 2023, but included in part of the refinancing of the Company's overall long-term debt, the Company entered into a Senior Credit Facility Agreement with Fifth Third Bank, National Association ("Fifth Third") as the administrative agent and collateral agent and a number of banks included in the syndicate to establish a senior revolving credit facility ("Senior Credit Facility Agreement") that matures on September 30, 2026. The Senior Credit Facility Agreement has aggregate maximum commitments of $100.0 million with current commitments of $75.0 million. Loans under the Senior Credit Facility Agreement bear interest at either the Adjusted Term SOFR (as defined in the Senior Credit Facility Agreement) or the Base Rate (as defined in the Senior Credit Facility Agreement) at the Company's option, plus an applicable margin ranging (i) for Adjusted Term SOFR loans, from 4.00% to 5.00%, and (ii) for Base Rate loans, from 3.00% to 4.00%, in each case calculated based on the ratio at such time of the outstanding principal loan amounts to the aggregate amount of lenders' commitments. To the extent that a payment default exists and is continuing, at the election of the Required Lenders (as defined in the Senior Credit Facility Agreement) under the Senior Credit Facility Agreement, all amounts outstanding under the Senior Credit Facility Agreement will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto. The Company is able to repay any amounts borrowed prior to the maturity date without premium or penalty. The Senior Credit Facility Agreement is guaranteed by the Company and certain of its subsidiaries and is secured by a first lien security interest in substantially all assets of the Company and certain of its subsidiaries.

Underwritten equity offering. In July 2023, we completed an underwritten equity offering of 14,835,000 shares of common stock at a price of $10.50, netting proceeds to the Company of approximately $151.2 million that was used for working capital and to otherwise enhance near-term liquidity. Certain of our existing stockholders, including the John Paul DeJoria Family Trust, a holder of approximately 12% of our common stock, and Jack Hightower, our Chief Executive Officer and Chairman of our Board of Directors, and entities and individuals associated with them, purchased an aggregate 10,029,070 shares in the offering. The underwriters in such offering received a reduced underwriting discount on such shares purchased by these persons or entities compared with the other shares sold to the public in the offering.

Dividends and dividend equivalents. In January, April, July and October 2023, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.8 million, $2.8 million, $3.2 million and $3.2 million, respectively, in dividends being paid on February 24, 2023, May 25, 2023, August 25, 2023 and November 22, 2023, respectively. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $282,000 in February 2023, $286,000 in May 2023, $334,000 in August 2023 and $348,000 in November 2023 and accrued a dividend equivalent per share to all unvested stock option holders which is payable upon vesting, assuming no forfeitures. In addition, the Company accrued an additional combined $53,000 in February 2023, $53,000 in May 2023, $54,000 in August 2023 and $54,000 in November 2023 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

Acquisitions. During the year ended December 31, 2023, the Company incurred a total of $15.1 million in acquisition costs primarily to acquire additional bolt-on undeveloped acreage contiguous to its Flat Top and Signal Peak operating areas.

Crude Oil and Natural Gas Industry Considerations. Since mid-2020, crude oil prices have improved, with demand steadily increasing. In addition, sanctions and import bans on Russia have been implemented by various countries in response to the war in Ukraine, further impacting global crude oil supply. As a result of crude oil and natural gas supply constraints, there have been significant increases in European energy costs, which have resulted in inflationary pressures throughout Europe, increasing prospects of recession in many countries throughout the continent. In April 2023, OPEC announced production cuts of around 1.16 million Bopd. On June 4, 2023, OPEC agreed to extend these previously announced production cuts through the end of 2024. On July 3, 2023, Saudi Arabia announced it was extending voluntary cuts through August 2023. However, as a result of current global supply and demand imbalances, crude oil and natural gas prices remain strong, although down from the prior year. In addition, the war between Russia and Ukraine and ongoing conflict between Israel and Hamas and other tensions in the Middle East have resulted in global supply chain disruptions, which has led to significant cost inflation. Such impacts may also be exacerbated by recent developments in the Israel-Hamas conflict. Specifically, the Company's 2023 and 2024 capital program has been and continues to be impacted by higher inflation in steel, diesel, chemical prices and services, among other items.

Global crude oil price levels and inflationary pressures will ultimately depend on various factors that are beyond the Company's control, such as (i) general economic conditions and increasing expectations that the world may be heading into a global recession, (ii) the ability of OPEC and other crude oil producing nations to manage the global crude oil supply, (iii) the impact of sanctions and import bans on production from Russia and any resulting impact on production from the Israel-Hamas conflict, (iv) the timing and supply impact of any Iranian or Venezuelan sanction relief on their ability to export crude oil, (v) the global supply chain constraints associated with manufacturing and distribution delays, (vi) oilfield service demand and cost inflation, and (vii) political stability of crude oil consuming countries. The Company continues to assess and monitor the impact of these factors and consequences on the Company and its operations.

Outlook

HighPeak Energy's financial position and future prospects, including its revenues, operating results, profitability, liquidity, future growth and the value of its assets, depend heavily on prevailing commodity prices. The crude oil and natural gas industry is cyclical and commodity prices are highly volatile and subject to a high degree of uncertainty. For example, during the period from January 1, 2020 through December 31, 2023, the calendar month average NYMEX WTI crude oil price per Bbl ranged from a low of \$16.70 to a high of \$114.34, and the last trading day NYMEX natural gas price per MMBtu ranged from a low of \$1.50 to a high of \$9.35.

The markets for the commodities produced by our industry strengthened in 2021 and continued to remain strong through 2023 and into 2024, although the market has decreased from 2022 levels overall, as a result of increased demand outpacing increased supply for each of the commodities we produce. Prices for the commodities produced by our industry improved from historic lows in 2020, with crude oil and natural gas prices reaching their highest average annual price since 2014. However, there are many factors beyond the Company's control, including commodity markets, unavailability or high cost of drilling rigs, equipment, supplies, personnel, frac crews and oilfield services or supply constraints remain subject to heightened levels of uncertainty as a result of the conflicts in Russia and Ukraine and in Israel and Hamas, elevated interest rates and associated policies of the Federal Reserve, which could adversely affect HighPeak Energy. For additional information on the risks, see "Part I, Item 1A. Risk Factors."

Given the dynamic nature of this situation, the Company is maintaining flexibility in its capital plan as indicated by its recent shift to an anticipated two (2) drilling rig program for 2024. The Company will continue to evaluate drilling and completion activity on an economic basis, with future activity levels assessed monthly. Despite continuing impacts of the factors listed above and future uncertainty, we are focused on maintaining our ability to sustain strong operational performance and financial stability while maximizing returns, improving leverage metrics, and increasing the value of our Midland Basin assets.

Strategic Alternatives

On January 23, 2023, the Company announced the intention of its Board to initiate a process to evaluate certain strategic alternatives to maximize shareholder value, including a potential sale of the Company. Texas Capital Securities and Wells Fargo Securities, LLC have been retained as a financial advisors with respect to this strategic alternatives process. To date, however, this process has been exploratory in nature and accordingly remains in preliminary stages, with our discussions to date with prospective counterparties generally excluding substantive discussions regarding potential valuation, structure or other key transaction terms. The Company has not set a timetable for the conclusion of this review, nor has it made any decisions related to any further actions or potential strategic alternatives at this time. There can be no assurance that the review will progress beyond this exploratory phase or result in any transaction or other strategic change or outcome. The Company does not intend to comment further regarding the strategic alternatives process unless and until our Board has approved a specific course of action or we have otherwise determined that further disclosure is appropriate or required by law.

Financial and Operating Performance

The Company's financial and operating performance for the year ended December 31, 2023 included the following highlights:

- Net income for the year ended December 31, 2023 was $215.9 million ($1.58 per diluted share) compared with $236.9 million for the year ended December 31, 2022. The primary components of the $21.0 million decrease in net income include:

  - a $246.7 million increase in DD&A expense due to an 86% increase in daily sales volumes as a result of the Company's successful horizontal drilling program, in addition to a 28% increase in the DD&A rate from $19.89 to $25.51 per Boe primarily as a result of significant inflationary pressures on capital costs;

  - a $27.3 million increase in loss on extinguishment of debt as a result of the Company refinancing its debt which resulted in the recognition of a loss thereon, which included $22.8 million of unamortized debt issuance costs and discounts and a make whole premium on the 10.625% Senior Notes of $4.5 million;

  - a $97.3 million increase in interest expense due to the increase in the Company's overall indebtedness and increased amortization of debt issuance costs and discounts;

  - a $75.8 million increase in lease operating expenses related primarily to the increased well count and production from the Company's successful horizontal drilling program, increased power and chemical costs, repair and maintenance costs and other inflationary pressures;

  - a $20.0 million increase in production and ad valorem taxes, primarily attributable to the 86% increase in daily sales volumes as a result of the Company's successful horizontal drilling program partially offset by 21% lower production taxes on a dollar per Boe basis due to lower overall realized prices of 21%, excluding the effects of derivatives;

  - an $8.3 million increase in the Company's other expenses primarily attributable to a contract settlement and repairs made in response to a fire at one of our production facilities;

  - a $4.1 million increase in the Company's general and administrative expenses primarily attributable to increased employee count, salary increases and annual bonuses in addition to increased internal and external audit costs and legal expenses as a result of the growth of the Company; and

  - a $4.1 million increase in exploration and abandonments expense primarily due to an increase in leasehold abandonments and plugging and abandonment expenses related to legacy vertical wells;

  Partially offset by:

  - a $355.6 million increase in crude oil, NGL and natural gas revenues due to an 86% increase in daily sales volumes resulting from the Company's successful horizontal drilling program, partially offset by a 21% decrease in average realized commodity prices per Boe, excluding the effects of derivatives;

  - a $87.6 million increase in the Company's net derivative instruments gain from a $60.0 million loss to a $27.6 million gain year over year as a result of its crude oil commodity contracts entered into and the decrease in crude oil prices thereafter;

  - a $9.5 million decrease in the Company's income tax expense primarily due to the net income realized during 2023 being less than the net income realized during 2022;

  - a $7.4 million decrease in the Company's stock-based compensation expense as a result of fewer stock options being issued relative to the prior period; and

  - a $2.6 million increase in the Company's interest income due to the increased cash on hand (interest-bearing) subsequent to the closing of the Term Loan Credit Agreement.

- During the year ended December 31, 2023, average daily sales volumes totaled 45,577 Boepd, an increase of 86% over 2022, due to the Company's successful horizontal drilling program in the Permian Basin.

- Weighted average realized crude oil prices per Bbl decreased during the year ended December 31, 2023 to $78.26, excluding the effects of derivatives, compared with $94.61 for 2022. Weighted average realized NGL prices per Bbl decreased during the year ended December 31, 2023 to $21.51, compared with $35.67 for 2022. Weighted average realized natural gas prices per Mcf decreased to $1.56 during the year ended December 31, 2023, compared with $5.36 during 2022.

- Cash provided by operating activities totaled $756.4 million for the year ended December 31, 2023, compared with $504.0 million for the year ended December 31, 2022.

Derivative Financial Instruments

Derivative financial instrument exposure. As of December 31, 2023, the Company was a party to the following open crude oil derivative financial instruments.

					Swaps	Enhanced Collars & Deferred Premium Puts		
Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Price per Bbl	Floor or Strike Price per Bbl	Ceiling Price per Bbl	Deferred Premium Payable per Bbl
Crude Oil:								
Jan - Mar	2024	Swap	4,000	WTI	$ 84.00	$ —	$ —	$ —
Jan - Mar	2024	Collar	6,000	WTI	$ —	$ 80.00	$ 100.00	$ 3.50
Jan - Mar	2024	Put	20,000	WTI	$ —	$ 66.44	$ —	$ 5.00
Apr - Jun	2024	Swap	4,000	WTI	$ 84.00	$ —	$ —	$ —
Apr - Jun	2024	Collar	5,500	WTI	$ —	$ 69.73	$ 95.00	$ 0.61
Apr - Jun	2024	Put	14,000	WTI	$ —	$ 60.41	$ —	$ 5.00
Jul - Sep	2024	Swap	4,000	WTI	$ 84.00	$ —	$ —	$ —
Jul - Sep	2024	Collar	1,500	WTI	$ —	$ 69.00	$ 95.00	$ 0.85
Jul - Sep	2024	Put	14,000	WTI	$ —	$ 60.41	$ —	$ 5.00
Oct - Dec	2024	Swap	5,500	WTI	$ 76.37	$ —	$ —	$ —
Oct - Dec	2024	Collar	10,600	WTI	$ —	$ 65.68	$ 90.32	$ 1.85
Oct - Dec	2024	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00
Jan - Mar	2025	Swap	5,500	WTI	$ 76.37	$ —	$ —	$ —
Jan - Mar	2025	Collar	8,000	WTI	$ —	$ 65.00	$ 90.00	$ 2.12
Jan - Mar	2025	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00
Apr - Jun	2025	Swap	5,500	WTI	$ 76.37	$ —	$ —	$ —
Apr - Jun	2025	Collar	7,000	WTI	$ —	$ 65.00	$ 90.08	$ 2.28
Apr - Jun	2025	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00
Jul - Sep	2025	Swap	3,000	WTI	$ 75.85	$ —	$ —	$ —
Jul - Sep	2025	Collar	7,000	WTI	$ —	$ 65.00	$ 90.08	$ 2.28
Jul - Sep	2025	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00

The estimated fair value of the outstanding open derivative financial instruments as of December 31, 2023 was a net asset of $34.4 million which is included in current assets, noncurrent assets, current liabilities and noncurrent liabilities on the Company's consolidated balance sheet as of December 31, 2023. During the year ended December 31, 2023, the Company recognized a net derivative gain of $27.6 million, including a $51.8 million mark-to-market gain partially offset by $24.2 million in net monthly settlement payments.

Subsequent to yearend, the Company entered into fixed price basis swaps for the spread between the Cushing, Oklahoma crude oil price and the Midland WTI crude oil price. The weighted average differential represents the amount of premium to the Cushing, Oklahoma crude oil price for the notional volumes covered by the basis swap contracts as shown below.

					Swaps
Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Weighted Average Differential per Bbl
Crude Oil:					
Jan - Mar	2024	Basis Swap	16,484	Argus WTI Midland	$ 1.12
Apr - Jun	2024	Basis Swap	25,000	Argus WTI Midland	$ 1.12
Jul - Sep	2024	Basis Swap	25,000	Argus WTI Midland	$ 1.12
Oct - Dec	2024	Basis Swap	25,000	Argus WTI Midland	$ 1.12

Operations and Drilling Highlights

Average daily crude oil, NGL and natural gas sales volumes are as follows:

	Year Ended December 31, 2023
Crude Oil (Bbls)	38,041
NGL (Bbls)	4,239
Natural Gas (Mcf)	19,777
Total (Boe)	45,577

The Company's liquids production was 93% of total production on a Boe basis for the year ended December 31, 2023.

Costs incurred are as follows (in thousands):

	Year Ended December 31, 2023
Unproved property acquisition costs	$ 11,777
Proved acquisition costs	3,308
Total acquisitions	15,085
Development costs	481,528
Exploration costs	527,502
Total finding and development costs	1,024,115
Asset retirement obligations	6,048
Total costs incurred	$ 1,030,163

Development/service and exploration/extension drilling activity is as follows:

	Year Ended December 31, 2023	
	Development/ Service	Exploration/ Extension
Beginning wells in progress	3	62
Well spud	45	51
Successful wells	(32)	(98)
Ending wells in progress	16	15

Results of Operations

Results of operations should be read together with the Company's consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report. See the Company's Annual Report on Form 10-K for the year ended December 31, 2022 filed with the SEC on March 6, 2023 for a discussion of the Company's 2022 results of operations compared with the Company's 2021 results of operations.

Sources of Revenues

The Company's revenues, which are entirely originated in the continental United States, are derived from the sale of crude oil and natural gas production and the sale of NGL that are extracted from natural gas during processing. For the years ended December 31, 2023, 2022 and 2021, revenues from our assets were derived approximately 98%, 95% and 96%, respectively, from crude oil sales and 2%, 5% and 4%, respectively, from NGL and natural gas sales.

The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with significant purchasers. For the year ended December 31, 2023, sales to the Company's largest purchaser accounted for approximately 82% of the Company's total crude oil, NGL and natural gas sales revenues. The Company generally does not require collateral and does not believe the loss of this particular purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

The Company's revenues are presented net of certain gathering, transportation and processing expenses incurred to deliver production of its assets' crude oil, NGL and natural gas to the market. Cost levels of these expenses can vary based on the volume of crude oil, NGL and natural gas produced as well as the cost of commodity processing. Crude oil, NGL and natural gas prices are inherently volatile and are influenced by many factors outside the Company's control. To reduce the impact of fluctuations in crude oil, NGL and natural gas prices on revenues, the Company may periodically enter into derivative contracts with respect to a portion of its estimated crude oil, NGL and natural gas production through various transactions that fix or set a floor price for future prices received.

Principal Components of Cost Structure

Costs associated with producing crude oil, NGL and natural gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production, and others are a function of the number of wells owned. The sections below summarize the primary operating costs typically incurred:

- ***Lease Operating Expenses.*** Lease operating expenses ("LOE") are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water injection and disposal, workover rigs and workover expenses, materials and supplies comprise the most significant portion of LOE. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to pumping equipment or surface facilities result in increased LOE in periods during which they are performed. Certain operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, power costs are incurred in connection with various production-related activities, such as pumping to recover crude oil and natural gas and separation and treatment of water produced in connection with crude oil and natural gas production.

  The Company monitors the operation of its assets to ensure that it is incurring LOE at an acceptable level. For example, it monitors LOE per Boe to determine if any wells or properties should be shut-in, recompleted or sold. This unit rate also allows the Company to monitor these costs to identify trends and to benchmark against other producers. Although the Company strives to reduce its LOE, these expenses can increase or decrease on a per-unit basis as a result of various factors as it operates its assets or makes acquisitions and dispositions of properties. For example, the Company may increase field-level expenditures to optimize their operations, incurring higher expenses in one quarter relative to another, or they may acquire or dispose of properties that have different LOE per Boe. These initiatives would influence overall operating cost and could cause fluctuations when comparing LOE on a period-to-period basis.

- ***Production and other taxes.*** Production and other taxes are paid on produced crude oil and natural gas based on rates established by federal, state or local taxing authorities. In general, production and other taxes paid correlate to changes in crude oil, NGL and natural gas revenues. Production taxes are based on the market value of production at the wellhead. The Company is also subject to ad valorem taxes in the counties where production is located. Ad valorem taxes are based on the fair market value of the mineral interests for producing wells.

- ***Depletion – Crude Oil and Natural Gas Properties.*** Depletion is the systematic expensing of the capitalized costs incurred to acquire and develop crude oil and natural gas properties. The Company uses the successful efforts method of accounting for crude oil and natural gas properties. Accordingly, all costs associated with acquisition, successful exploration/extension wells and development of crude oil and natural gas reserves, including directly related overhead costs and asset retirement costs are capitalized. However, the costs of abandoned properties, exploratory dry holes, geophysical costs and annual lease rentals are charged to expense as incurred. All capitalized costs of crude oil and natural gas properties are amortized on the unit-of-production method using estimates of proved reserves. Any remaining investments in unproved properties are not amortized until proved reserves associated with the projects can be determined or until impairment occurs.

- ***General and Administrative Expenses.*** General and administrative expenses ("G&A") are costs incurred for overhead, including payroll and benefits for corporate staff and costs of maintaining a headquarters, costs of managing production and development operations, IT expenses and audit and other fees for professional services, including legal compliance and acquisition-related expenses.

Results of Operations

Results of operations should be read together with the Company's consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

Crude Oil, NGL and natural gas revenues.

The Company's revenues are derived from the sales of crude oil, NGL and natural gas production. Increases or decreases in the Company's revenues, profitability and future production are highly dependent on commodity prices. Prices are market driven and future prices will fluctuate due to supply and demand factors, availability of transportation, seasonality, geopolitical developments and economic factors, among other items.

Crude oil, NGL and natural gas revenues are as follows (in thousands):

	Year Ended December 31,		
	2023	2022	Change
Crude oil, NGL and natural gas revenues	$ 1,111,293	$ 755,686	$ 355,607

Average daily sales volumes are as follows:

	Year Ended December 31,		
	2023	2022	% Change
Crude Oil (Bbls)	38,041	20,718	84%
NGL (Bbls)	4,239	2,249	88%
Natural Gas (Mcf)	19,777	9,105	117%
Total (Boe)	45,577	24,485	86%

The increase in average daily Boe sales volumes for the year ended December 31, 2023, compared with 2022 was due to the Company's successful horizontal drilling program. This increase could have been more significant had we not had a portion of our production curtailed during the year primarily due to a combination of extended maintenance downtime and start-up delays at gas processing plants owned by one of our primary gas midstream providers which resulted in periodic takeaway and processing constraints. This amounted to approximately 2,000 Boe in daily production that we were not able to sell for the year ended December 31, 2023.

The crude oil, NGL and natural gas prices that the Company reports are based on the market prices received for each commodity. The weighted average prices, excluding the effects of derivatives, are as follows:

	Year Ended December 31,		
	2023	2022	% Change
Crude oil per Bbl	$ 78.26	$ 94.61	(17)%
NGL per Bbl	$ 21.51	$ 35.67	(40)%
Natural gas per Mcf	$ 1.56	$ 5.36	(71)%
Total per Boe	$ 66.80	$ 84.56	(21)%

The decrease in prices for crude oil, NGL and natural gas for the year ended December 31, 2023, compared with 2022 was due to a lower commodity price environment.

Crude oil and natural gas production costs.

Crude oil and natural gas production costs are as follows (in thousands):

	Year Ended December 31,		
	2023	2022	Change
Crude oil and natural gas production costs	$ 145,362	$ 69,599	$ 75,763

Crude oil and natural gas production costs per Boe are as follows:

	Year Ended December 31, 2023	Year Ended December 31, 2022	% Change
Lease operating expense	$ 8.04	$ 7.49	7%
Workover costs	0.70	0.30	133%
	$ 8.74	$ 7.79	12%

Lease operating expense per Boe for 2023 increased slightly compared with 2022. This is largely due to the aforementioned curtailed production during 2023. The increase in workover costs year over year can be attributed to wells getting older and beginning to need more repair and maintenance from time to time.

Production and ad valorem taxes.

Production and ad valorem taxes are as follows (in thousands):

	Year Ended December 31, 2023	Year Ended December 31, 2022	Change
Production and ad valorem taxes	$ 58,472	$ 38,440	$ 20,032

In general, production taxes and ad valorem taxes are directly related to production and commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices and valuations as of the first of the year, whereas production taxes are based upon current year commodity prices and sales volumes.

Production and ad valorem taxes per Boe are as follows:

	Year Ended December 31, 2023	Year Ended December 31, 2022	% Change
Production taxes per Boe	$ 3.19	$ 4.04	(21)%
Ad valorem taxes per Boe	$ 0.32	$ 0.26	23%
	$ 3.51	$ 4.30	(18)%

Production taxes per Boe for the year ended December 31, 2023, compared with 2022, decreased primarily due to the 21% overall decrease in realized sales prices. The increase in ad valorem taxes per Boe for the year ended December 31, 2023, compared with 2022, was primarily due to the increase in commodity prices in 2022 and a significant number of wells that came on production during 2022 that had no ad valorem tax in 2022. 2023 was the first year these wells were assessed ad valorem taxes. In Texas, ad valorem taxes are based on a valuation of the wells on January 1 of a given year.

Exploration and abandonments expense.

Exploration and abandonment expense details are as follows (in thousands):

	Year Ended December 31, 2023	Year Ended December 31, 2022	Change
Abandoned leasehold costs	$ 3,372	$ —	$ 3,372
Geologic and geophysical personnel costs	993	1,003	(10)
Plugging and abandonment expense	745	—	745
Geologic and geophysical data costs	124	146	(22)
Exploration and abandonments expense	$ 5,234	$ 1,149	$ 4,085

The increase in exploration and abandonment expenses is primarily the result of $3.4 million in abandoned leasehold costs related to undeveloped acreage that was not in an area where the Company had current plans to drill and thus the leases were allowed to expire. The Company remains committed to maintaining as much of its undeveloped acreage leasehold position as possible, but from time to time, certain acreage is not able to be extended at reasonable prices and we are not able to get a drilling rig in the area in time to save the leases for a multitude of reasons. In addition, the Company spent $745,000 on plugging various old vertical wells across our acreage position in accordance with applicable regulations.

Depletion, depreciation and amortization expense.

DD&A expense is as follows (in thousands):

	Year Ended December 31,		
	2023	2022	Change
DD&A expense	$ 424,424	$ 177,742	$ 246,682

DD&A expense per Boe is as follows:

	Year Ended December 31,		
	2023	2022	% Change
DD&A expense per Boe	$ 25.51	$ 19.89	28%

The increase in DD&A expense is primarily due to the increased production associated with our successful horizontal drilling program. The increase in DD&A expense per Boe can be primarily attributed to inflationary pressures and lower well performance as we test new areas and new geologic horizons.

General and administrative expense.

General and administrative expense and stock-based compensation expense are as follows (in thousands):

	Year Ended December 31,		
	2023	2022	Change
General and administrative expense	$ 16,598	$ 12,470	$ 4,128
Stock-based compensation expense	$ 25,957	$ 33,352	$ (7,395)

General and administrative expense per Boe is as follows:

	Year Ended December 31,		
	2023	2022	% Change
General and administrative expense per Boe	$ 1.00	$ 1.40	(29)%

The increase in general and administrative expense for the year ended December 31, 2023 is primarily as a result of increased employee count, salary increases and annual bonuses in addition to an increase in internal and external audit costs and legal expenses related to the growth of the Company.

The decrease in noncash stock-based compensation expense is due to fewer awards granted in 2023 compared with 2022.

Interest expense.

Interest expense is as follows (in thousands):

	Year Ended December 31,		
	2023	2022	Change
Interest expense on Term Loan Credit Agreement	$ 47,820	$ —	$ 47,820
Interest expense on Prior Credit Agreement	30,493	14,022	16,471
Interest expense on 10.625% Senior Notes	27,064	3,593	23,471
Interest expense on 10.000% Senior Notes	15,875	19,625	(3,750)
Interest expense on Senior Credit Facility Agreement	98	—	98
Amortization of discounts	15,140	7,735	7,405
Amortization of debt issuance costs	11,411	5,635	5,776
	$ 147,901	$ 50,610	$ 97,291

The increase in interest expense can be primarily attributed to higher interest rates in 2023 compared to 2022, but more importantly, to increased borrowings under the Term Loan Credit Agreement beginning in September 2023, increased borrowings under the Prior Credit Agreement throughout 2023 until September 2023 when it was paid in full and the issuance of $250.0 million of the Company’s 10.625% Senior Notes in late-2022 that were also paid off in September 2023. In addition, the Company also experienced an increase in both amortization of discounts and debt issuance costs with the increase in debt issuances from year to year.

Derivative loss, net.

Derivative loss, net is as follows (in thousands):

	Year Ended December 31, 2023	Year Ended December 31, 2022	Change
Noncash gain (loss) on derivative instruments, net	$ 51,796	$ (58,096)	$ 109,892
Cash paid on settlement of derivative instruments, net	(24,194)	(1,909)	(22,285)
Gain (loss) on derivative instruments, net	$ 27,602	$ (60,005)	$ 87,607

The Company primarily utilizes commodity swap contracts, enhanced collars and deferred premium puts to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budget and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The Company's Term Loan Credit Agreement and Senior Credit Facility Agreement require the Company to hedge certain quantities of its projected crude oil production. The Company may also, from time to time, utilize natural gas contracts or interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness. The above mark-to-market gains and losses and cash settlements relate to crude oil and natural gas derivative swap, enhanced collars and deferred premium put contracts.

Income tax expense.

	Year Ended December 31,		
	2023	2022	Change
Income tax expense (in thousands)	$ 65,905	$ 75,361	$ (9,456)
Effective income tax rate	23.4%	24.1%	(0.7)%

The change in income tax expense during the year ended December 31, 2023, compared with 2022, was due to decreased net income during the year ended December 31, 2023 compared with 2022. The effective income tax rate differs from the statutory rate primarily due to a revision on the deferred tax asset related to certain stock-based compensation and permanent differences between GAAP income and taxable income. See Note 13 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report for additional information.

Liquidity and Capital Resources

Liquidity. The Company's primary sources of short-term liquidity are (i) cash and cash equivalents, including remaining cash proceeds from our recent $1.2 billion Term Loan Credit Agreement, (ii) net cash provided by operating activities, (iii) unused borrowing capacity under the Senior Credit Facility Agreement, (iv) on an opportunistic basis, other issuances of debt or equity securities and (v) other sources, such as sales of nonstrategic assets.

The Company's short-term and long-term liquidity requirements consist primarily of (i) capital expenditures, (ii) acquisitions of crude oil and natural gas properties, (iii) payments of contractual obligations, (iv) working capital obligations, and (v) interest payments on and amortization of its indebtedness. Funding for these cash needs may be provided by any combination of the Company's sources of liquidity. Although the Company expects its sources of funding will be adequate to fund its 2024 planned capital expenditures and provide adequate liquidity to fund other needs, no assurance can be given that such funding sources will be adequate to meet the Company's future needs.

2024 capital budget. The Company's capital budget for 2024 is expected to be in the range of approximately $450 to $525 million for drilling, completion, facilities and equipping crude oil wells plus $50 to $60 million for field infrastructure buildout and other costs. The 2024 capital budget excludes acquisitions, asset retirement obligations, geological and geophysical general and administrative expenses and corporate facilities. HighPeak Energy expects to fund its forecasted capital expenditures with cash on its balance sheet, cash generated by operations and borrowings under the Senior Credit Facility Agreement, if needed. The Company's capital expenditures for the year ended December 31, 2023 were $1.0 billion, excluding acquisitions.

The budget above assumes that the Company will operate an average of two (2) drilling rigs and an average of one (1) frac crew during 2024. However, there are many factors and consequences beyond the Company's control, such as policies of the Biden Administration, economic downturn or potential recession, geo-political risks and additional actions by businesses, and OPEC and other cooperating countries, that may have an impact on the Company's future results and drilling plans. For additional information on the risks, see "Part I, Item 1A. Risk Factors." Given the dynamic nature of this situation, the Company is maintaining flexibility in its capital plan and will continue to evaluate drilling and completion activity on an economic basis, with future activity levels assessed monthly.

Capital resources.

As of December 31, 2023, the Company had $1.2 billion in outstanding borrowings under the Term Loan Credit Agreement and approximately $68.9 million available to borrow under the Senior Credit Facility Agreement. The Company also had unrestricted cash on hand of $194.5 million as of December 31, 2023.

Cash flows from operating, investing and financing activities are summarized below (in thousands).

	Year Ended December 31,		
	2023	2022	Change
Net cash provided by operating activities	$ 756,389	$ 504,014	$ 252,375

Net cash used in investing activities	$	(1,125,935)	$	(1,182,408)	$	56,473
Net cash provided by financing activities	$	533,557	$	674,029	$	(140,472)

Operating activities. The increase in net cash flow provided by operating activities for the year ended December 31, 2023, compared with 2022, was primarily due to an increase in cash flow from the statement of operations related mostly to increased revenues associated with increased production volumes as a result of our successful horizontal drilling program, coupled with a positive working capital change of $52.5 million.

Investing activities. The slight decrease in net cash used in investing activities for the year ended December 31, 2023, compared with 2022, was primarily due to a decrease in additions to crude oil and natural gas properties including drilling and completion operations and acquisitions in total.

Financing activities. The Company's significant financing activities are as follows:

- 2023: The Company (i) borrowed $1.4 billion and repaid $1.0 billion for a net increase in long-term debt related to the now refinanced debt in the form of the Term Loan Credit Agreement of $425.0 million, (ii) received $155.8 million from the issuance of 14,835,000 shares of common stock in a public offering, (iii) received $4.2 million in proceeds from the exercises of warrants and stock options of the Company, (iv) paid dividends to its common stockholders of $11.9 million and dividend equivalents to certain holders of vested stock options of $1.3 million, (v) spent $28.4 million on debt issuance costs primarily related to the issuance of the Term Loan Credit Agreement and to a lesser extent the new Senior Credit Facility Agreement and amendments to increase its borrowing capacity under the Prior Credit Agreement, (vi) spent $5.4 million in stock offering costs related to the public offering and (vii) spent $4.5 million in make whole payments to retire the 10.625% Senior Notes early.

- 2022: The Company (i) borrowed $925.0 million and repaid $755.0 million for a net increase in long-term debt related to the Prior Credit Agreement of $170.0 million, (ii) issued an aggregate principal amount of $225.0 million ($210.2 million net of discounts) of its 10.000% Senior Notes and an aggregate principal amount of $250.0 million ($230.0 million net of discounts) of its 10.625% Senior Notes, (iii) received $85.0 million from the issuance of 3,933,376 shares of common stock in a private placement, (iv) received $7.9 million in proceeds from the exercises of warrants and stock options of the Company, (v) paid dividends to its common stockholders of $10.4 million and dividend equivalents to certain holders of vested stock options of $1.2 million and (vi) spent $17.1 million on debt issuance costs related to amendments to increase its borrowing capacity under the Prior Credit Agreement and the issuance of the 10.000% Senior Notes and 10.625% Senior Notes.

Interest Rate Risk. We are exposed to market risk due to the floating interest rate associated with any outstanding balance on the Term Loan Credit Agreement and the Senior Credit Facility Agreement. As of December 31, 2023, we had a $1.2 billion outstanding balance on the Term Loan Credit Agreement and zero outstanding on the Senior Credit Facility Agreement. Our Term Loan Credit Agreement fixes the interest rate for all of the principal balance for a period of three months and the Senior Credit Facility Agreement allows us to fix the interest rate for all or a portion of the principal balance for a period of up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the Term Loan Credit Agreement's and Senior Credit Facility Agreement's fair value but will not impact results of operations or cash flows. Conversely, for the portion of the Term Loan Credit Agreement and Senior Credit Facility Agreement that has a floating interest rate, interest rate changes will not affect the fair value but will impact future results of operations and cash flows.

Commodity Price Risk. The prices we receive for our crude oil, NGL and natural gas production directly impact our revenue, profitability, access to capital, and future rate of growth. Crude oil, NGL and natural gas prices are subject to unpredictable fluctuations resulting from a variety of factors, including changes in supply and demand and the macroeconomic environment, and seasonal anomalies, all of which are typically beyond our control. The markets for crude oil, NGL and natural gas have been volatile, especially over the last several years. Commodity prices have improved from historic lows in 2020 resulting from the impacts of the COVID-19 pandemic. Additionally, commodity prices are subject to heightened levels of uncertainty related to geopolitical issues such as the ongoing armed conflict between Russia and Ukraine. The realized prices we receive for our production also depend on numerous factors that are typically beyond our control. Based on our 2023 sales volumes and excluding the effects on derivatives, a $1.00 per barrel increase (decrease) in the weighted average crude oil price for the year ended December 31, 2023 would have increased (decreased) the Company's crude oil and NGL revenues by approximately $14.3 million and a $0.10 per Mcf increase (decrease) in the weighted average natural gas price for the year ended December 31, 2023 would have increased (decreased) the Company's natural gas revenues by approximately $722,000.

We enter into commodity derivative contracts to reduce the risk of fluctuations in commodity prices. The fair value of our commodity derivative contracts is largely determined by estimates of the forward curves of the relevant price indices. As of December 31, 2023, a $1.00 increase (decrease) in the forward curves associated with our crude oil commodity derivative instruments would have changed our net derivative positions for these products by approximately $6.8 million.

Contractual obligations. The Company's contractual obligations include leases (primarily related to contracted drilling rigs, equipment and office facilities), capital funding obligations and other liabilities. Other joint owners in the properties operated by the Company could incur portions of the costs represented by these commitments.

Non-GAAP Financial Measures

EBITDAX represents net income before interest expense, interest and other income, income taxes, depletion, depreciation, and amortization, accretion of discount on asset retirement obligations, exploration and abandonment expense, non-cash stock-based compensation expense, noncash derivative gains and losses, other expense, gains and losses on divestitures and certain other items. EBITDAX excludes certain items we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. EBITDAX is a non-GAAP measure that we believe provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. In addition, EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the crude oil and natural gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. EBITDAX should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because EBITDAX excludes some, but not all items that affect net income and may vary among companies, the EBITDAX amounts presented may not be comparable to similar metrics of other companies.

We are also subject to financial covenants under our Term Loan Credit Agreement and Senior Credit Facility Agreement based on EBITDAX ratios as further described in Note 7 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report. The Term Loan Credit Agreement and Senior Credit Facility Agreement provide a material source of liquidity for us. Under the terms of our Term Loan Credit Agreement and the Senior Credit Facility Agreement, if we fail to comply with the covenants that establish a maximum permitted ratio of total net leverage or a minimum permitted ratio of asset coverage, we would be in default, an event that would accelerate repayments under the Term Loan Credit Agreement and prevent us from borrowing under the Senior Credit Facility Agreement and would therefore materially limit a significant source of our liquidity. In addition, if we are in default under the Term Loan Credit Agreement and the Senior Credit Facility Agreement and are unable to obtain a waiver of that default from our lenders, lenders under those agreements would be entitled to exercise all of their remedies for default.

The following table provides a reconciliation of our net income (GAAP) to EBITDAX (non-GAAP) for the periods presented (in thousands):

	Year Ended December 31,		
	2023	**2022**	**2021**
Net income	$ 215,866	$ 236,854	$ 55,559
Interest expense	147,901	50,610	2,484
Interest and other income	(2,908)	(266)	(1)
Income tax expense	65,905	75,361	16,904
Depletion, depreciation and amortization	424,424	177,742	65,201
Accretion of discount	522	370	167
Exploration and abandonment expense	5,234	1,149	1,549
Stock-based compensation	25,957	33,352	6,676
Derivative related noncash activity	(51,796)	1,909	15,467
Loss on extinguishment of debt	27,300	—	—
Other expense	8,262	—	167
EBITDAX	$ 866,667	$ 577,081	$ 164,173

Critical Accounting Estimates

The Company prepares its consolidated financial statements for inclusion in this Annual Report in accordance with GAAP. See Note 2 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report for additional information. The following is a discussion of the Company's most critical accounting estimates, judgments and uncertainties that are inherent in the Company's application of GAAP.

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for crude oil and natural gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that net assets and net income are more conservatively measured under the successful efforts method of accounting for crude oil and natural gas producing activities than under the full cost method, particularly during periods of active exploration. The critical difference between the successful efforts method of accounting and the full cost method is that under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of DD&A expense.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Annual Report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this Annual Report as of December 31, 2023, 2022 and 2021 was prepared by independent petroleum engineers. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, proved reserve estimates will be different from the quantities of crude oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions, positively or negatively, to the estimate of proved reserves. For the years ended December 31, 2023, 2022 and 2021, net downward revisions of our proved reserves totaled approximately 16,093 MBoe, 9,211 MBoe and 1,658 MBoe, respectively. We cannot predict the amounts or timing of future reserve revisions or removals.

It should not be assumed that the standardized measure included in this Annual Report as of December 31, 2023 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the 2023 standardized measure on a twelve-month average of commodity prices on the first day of each month in 2023 and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Items 1 and 2. Business and Properties" and Unaudited Supplementary Data included in "Item 8. Financial Statements and Supplementary Data" for additional information.

The Company's estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which the Company records DD&A expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of the Company's assessment of its proved properties for impairment.

Impairment of proved crude oil and natural gas properties. The Company performs assessments of its long-lived assets to be held and used, including proved crude oil and natural gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If there is an indication the carrying value of the assets may not be recovered, an impairment loss is recognized if the sum of the expected future cash flows is less than the carrying amount of the assets. In these circumstances, the Company recognizes an impairment charge for the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Proved crude oil and natural gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated. See Note 2 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Impairment of unproved crude oil and natural gas properties. At December 31, 2023, the Company carried unproved property costs of $72.7 million. Management assesses unproved crude oil and natural gas properties for impairment on a project-by-project basis. Management's impairment assessments include evaluating the results of exploration activities, management's price outlooks and planned future sales or expiration of all or a portion of such projects.

Suspended wells. The Company suspends the costs of exploratory wells that discover hydrocarbons pending a final determination of the commercial potential of the discovery. The ultimate disposition of these well costs is dependent on the results of future drilling activity and development decisions. If the Company decides not to pursue additional appraisal activities or development of these fields, the costs of these wells will be charged to exploration and abandonment expense.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

- The well has found a sufficient quantity of reserves to justify its completion as a producing well; and
- The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and economics associated with making a determination of its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predict the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found sufficient quantities of proved reserves to sanction the project or is determined to be noncommercial and is impaired. See Note 6 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Asset retirement obligations. The Company has significant obligations to remove tangible equipment and facilities and to restore the land at the end of crude oil and natural gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is generally made to the crude oil and natural gas property or other property and equipment balance. See Note 8 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Deferred tax asset valuation allowances. The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that its deferred tax assets will be realized prior to their expiration. HighPeak Energy monitors Company-specific, crude oil and natural gas industry and worldwide economic factors and based on that information, along with other data, reassesses the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurance that facts and circumstances will not materially change and require the Company to establish deferred tax asset valuation allowances in certain jurisdictions in a future period.

Uncertain tax positions. The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. If all or a portion of the unrecognized tax benefits is sustained upon examination by the taxing authorities, the tax benefit will be recorded as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recorded. As of December 2023, the Company did not have any unrecognized tax benefits. See Note 13 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Litigation and environmental contingencies. The Company makes judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments of the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. A liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimable. See Note 10 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Valuation of stock-based compensation. The Company calculates the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. The Company utilizes (i) the Black-Scholes option pricing model to measure the fair value of stock options, and (ii) the closing stock price on the date of grant for the fair value of unrestricted and restricted stock awards. See Note 9 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Valuation of other assets and liabilities at fair value. The Company periodically measures and records certain assets and liabilities at fair value. The assets and liabilities the Company measures and records at fair value on a recurring basis include commodity derivative contracts and interest rate contracts. Other assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. The assets and liabilities the Company measures and records at fair value on a nonrecurring basis include inventories, proved and unproved crude oil and natural gas properties and other long-lived assets that are written down to fair value when they are determined to be impaired or held for sale. The Company also measures and discloses certain financial assets and liabilities at fair value, such as long-term debt. The valuation methods used by the Company to measure the fair values of these assets and liabilities may require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as future prices, credit-adjusted risk-free rates and current volatility factors. See Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Recent Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Off-Balance Sheet Arrangements

Commitments and Contingencies are discussed in Note 10 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company’s major market risk exposure is the pricing it receives for its sales of crude oil, NGL and natural gas. Pricing for crude oil, NGL and natural gas has been volatile and unpredictable for several years, and HighPeak Energy expects this volatility to continue in the future.

During the period from January 1, 2020 through December 31, 2023, the calendar month average NYMEX WTI crude oil price per Bbl ranged from a low of $16.70 to a high of $114.34, and the last trading day NYMEX natural gas price per MMBtu ranged from a low of $1.50 to a high of $9.35. For the month of April 2020, the calendar month average NYMEX WTI crude oil price was $16.70 per Bbl and the last trading day NYMEX natural gas price was $1.63 per MMBtu. A $1.00 per barrel increase (decrease) in the weighted average crude oil price for the year ended December 31, 2023 would have increased (decreased) the Company’s crude oil and NGL revenues by approximately $14.3 million, excluding the effects of derivatives, and a $0.10 per Mcf increase (decrease) in the weighted average natural gas price for the year ended December 31, 2023 would have increased (decreased) the Company’s natural gas revenues by approximately $722,000, excluding the effects of derivatives.

Due to this volatility, the Company uses commodity derivative instruments, such as collars, puts, swaps and basis swaps, to hedge price risk associated with a portion of anticipated production. These hedging instruments allow the Company to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in crude oil and natural gas prices and provide increased certainty of cash flows for its drilling program. These instruments provide only partial price protection against declines in crude oil and natural gas prices and may partially limit the Company’s potential gains from future increases in prices. The Company enters into hedging arrangements to protect its capital expenditure budget. The Company’s Term Loan Credit Agreement and Senior Credit Facility Agreement require the Company to hedge certain quantities of its projected crude oil production. The Company does not enter into any commodity derivative instruments, including derivatives, for speculative or trading purposes.

Counterparty and Customer Credit Risk. The Company’s derivative contracts, if any, expose it to credit risk in the event of nonperformance by counterparties. It is anticipated that if the Company enters into any commodity contracts, the collateral for the outstanding borrowings under the Credit Agreements may be used as collateral for the Company’s commodity derivatives. The Company evaluates the credit standing of its counterparties as it deems appropriate. It is anticipated that any counterparties to HighPeak Energy’s derivative contracts would have investment grade ratings.

The Company’s principal exposures to credit risk are through receivables from the sale of crude oil and natural gas production due to the concentration of its crude oil and natural gas receivables with a few significant customers. The inability or failure of the Company’s significant customers to meet their obligations to the Company or their insolvency or liquidation may adversely affect the Company’s financial results.

The average forward prices based on December 31, 2023 market quotes were as follows:

	Year Ending December 31 2024	Year Ending December 31, 2025
Average forward NYMEX crude oil price per Bbl	$ 71.30	$ 65.10
Average forward NYMEX natural gas price per MMBtu	$ 2.67	$ 3.49

The average forward purchase prices based on March 1, 2024 market quotes were as follows:

	Remainder of 2024	Year Ending December 31, 2025
Average forward NYMEX crude oil price per Bbl	$ 75.97	$ 70.74
Average forward NYMEX natural gas price per MMBtu	$ 2.51	$ 3.46

Credit risk. The Company's primary concentration of credit risk is associated with (i) the collection of receivables resulting from the sale of crude oil and natural gas production and (ii) the risk of a counterparty's failure to meet its obligations under derivative contracts with the Company.

The Company monitors exposure to counterparties primarily by reviewing credit ratings, financial criteria and payment history. Where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the counterparty or other credit support. The Company's crude oil and natural gas is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. Historically, the Company's credit losses on crude oil and natural gas receivables have not been material.

The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

The Company entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with right of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative contract, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

Interest Rate Risk. At December 31, 2023, we had $1.2 billion outstanding under the Term Loan Credit Agreement and had $68.9 million of available borrowing capacity under the Senior Credit Facility Agreement. The Company is subject to interest rate risk on its variable rate debt from our Term Loan Credit Agreement and Senior Credit Facility Agreement. The Company also periodically has fixed rate debt but does not currently utilize derivative instruments to manage the economic effect of changes in interest rates. The impact of a 1% increase in interest rates on our outstanding debt as of December 31, 2023 would have resulted in an annual increase in interest expense of approximately $12.0 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of HighPeak Energy, Inc.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of HighPeak Energy, Inc. and its subsidiaries (the Company) as of December 31, 2023 and 2022, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ WEAVER AND TIDWELL, L.L.P.

We have served as the Company's auditor since 2020.

Fort Worth, Texas

March 6, 2024

HighPeak Energy, Inc.
Consolidated Balance Sheets
(in thousands, except share data)

	December 31, 2023	December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 194,515	$ 30,504
Accounts receivable	94,589	96,596
Derivative instruments	31,480	17
Inventory	7,254	13,275
Prepaid expenses	995	4,133
Total current assets	328,833	144,525
Crude oil and natural gas properties, using the successful efforts method of accounting:		
Proved properties	3,338,107	2,270,236
Unproved properties	72,715	114,665
Accumulated depletion, depreciation and amortization	(684,179)	(259,962)
Total crude oil and natural gas properties, net	2,726,643	2,124,939
Other property and equipment, net	3,572	3,587
Derivative instruments	16,059	—
Other noncurrent assets	5,684	6,431
Total assets	$ 3,080,791	$ 2,279,482
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 120,000	$ —
Accounts payable – trade	63,583	105,565
Accrued capital expenditures	39,231	91,842
Revenues and royalties payable	29,724	15,623
Other accrued liabilities	19,613	15,600
Derivative instruments	13,054	16,702
Accrued interest	1,398	13,152
Operating leases	528	343
Advances from joint interest owners	262	7,302
Total current liabilities	287,393	266,129
Noncurrent liabilities:		
Long-term debt, net	1,030,299	704,349
Deferred income taxes	197,068	131,164
Asset retirement obligations	13,245	7,502
Derivative instruments	65	691
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, $0.0001 par value, 10,000,000 shares authorized, none issued and outstanding at December 31, 2023 and 2022	—	—
Common stock, $0.0001 par value, 600,000,000 shares authorized, 128,420,923 and 113,165,027 shares issued and outstanding at December 31, 2023 and 2022, respectively	13	11
Additional paid-in capital	1,189,424	1,008,896
Retained earnings	363,284	160,740
Total stockholders' equity	1,552,721	1,169,647
Total liabilities and stockholders' equity	$ 3,080,791	$ 2,279,482

The accompanying notes are an integral part of these consolidated financial statements.

HighPeak Energy, Inc.
Consolidated Statements of Operations
(in thousands, except per share data)

	Years Ended December 31,		
	2023	**2022**	**2021**
Operating Revenues:			
Crude oil sales	$ 1,086,598	$ 715,469	$ 210,453
NGL and natural gas sales	24,695	40,217	9,671
Total operating revenues	1,111,293	755,686	220,124
Operating Costs and Expenses:			
Crude oil and natural gas production	145,362	69,599	25,053
Production and ad valorem taxes	58,472	38,440	10,746
Exploration and abandonments	5,234	1,149	1,549
Depletion, depreciation and amortization	424,424	177,742	65,201
Accretion of discount	522	370	167
General and administrative	16,598	12,470	8,885
Stock-based compensation	25,957	33,352	6,676
Total operating costs and expenses	676,569	333,122	118,277
Other expense	8,262	—	167
Income from operations	426,462	422,564	101,680
Interest and other income	2,908	266	1
Interest expense	(147,901)	(50,610)	(2,484)
Gain (loss) on derivative instruments, net	27,602	(60,005)	(26,734)
Loss on extinguishment of debt	(27,300)	—	—
Income before income taxes	281,771	312,215	72,463
Provision for income taxes	65,905	75,361	16,904
Net income	$ 215,866	$ 236,854	$ 55,559
Earnings per share:			
Basic net income	$ 1.64	$ 2.04	$ 0.55
Diluted net income	$ 1.58	$ 1.93	$ 0.54
Weighted average shares outstanding:			
Basic	117,956	104,738	93,127
Diluted	123,020	111,164	94,772
Dividends declared per share	$ 0.100	$ 0.100	$ 0.125

The accompanying notes are an integral part of these consolidated financial statements.

HighPeak Energy, Inc.
Consolidated Statements of Changes in Stockholders' Equity
(in thousands)

Years ended December 31, 2023, 2022 and 2021

	Shares Outstanding	Common Stock	Additional Paid-in-Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance, December 31, 2020	91,968	$ 9	$ 581,426	$ (107,209)	$ 474,226
Dividends declared ($0.125 per share)	—	—	—	(11,593)	(11,593)
Dividend equivalents declared on outstanding stock options ($0.125 per share)	—	—	—	(1,193)	(1,193)
Issuance of common stock	2,530	1	22,836	—	22,837
Exercise of warrants	554	—	5,466	—	5,466
Stock-based compensation costs:					
Shares issued upon options being exercised	154	—	1,573	—	1,573
Restricted shares issued to outside directors	68	—	—	—	—
Restricted shares issued to employee directors	1,500	—	—	—	—
Compensation costs included in net income	—	—	6,188	—	6,188
Net income	—	—	—	55,559	55,559
Balance, December 31, 2021	96,774	10	617,489	(64,436)	553,063
Dividends declared ($0.100 per share)	—	—	—	(10,623)	(10,623)
Dividend equivalents declared on outstanding stock options ($0.100 per share)	—	—	—	(1,055)	(1,055)
Stock issued for acquisitions	10,854	1	264,981	—	264,982
Stock issued in private placement	3,933	—	85,000	—	85,000
Stock issuance costs	—	—	(339)	—	(339)
Exercise of warrants	971	—	7,805	—	7,805
Stock-based compensation costs:					
Shares issued upon options being exercised	12	—	120	—	120
Restricted shares issued to outside directors	21	—	—	—	—
Restricted shares issued to employees	600	—	—	—	—
Compensation costs included in net income	—	—	33,840	—	33,840
Net income	—	—	—	236,854	236,854
Balance, December 31, 2022	113,165	11	1,008,896	160,740	1,169,647
Dividends declared ($0.100 per share)	—	—	—	(12,076)	(12,076)
Dividend equivalents declared on outstanding stock options ($0.100 per share)	—	—	—	(1,246)	(1,246)
Stock issued in public offering	14,835	2	155,766	—	155,768
Stock issuance costs	—	—	(5,371)	—	(5,371)
Exercise of warrants	350	—	4,028	—	4,028
Stock-based compensation costs:					
Shares issued upon options being exercised	12	—	148	—	148
Restricted shares issued to outside directors	59	—	—	—	—
Compensation costs included in net income	—	—	25,957	—	25,957
Net income	—	—	—	215,866	215,866
Balance, December 31, 2023	128,421	$ 13	$ 1,189,424	$ 363,284	$ 1,552,721

The accompanying notes are an integral part of these consolidated financial statements.

HighPeak Energy, Inc.
Consolidated Statements of Cash Flows
(in thousands)

	Years Ended December 31,		
	2023	2022	2021
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 215,866	$ 236,854	$ 55,559
Adjustments to reconcile net income to net cash provided by operations:			
Provision for deferred income taxes	65,905	75,361	16,904
Loss on extinguishment of debt	27,300	—	—
(Gain) loss on derivative instruments, net	(27,602)	60,005	26,734
Cash paid on settlement of derivative instruments	(24,194)	(58,096)	(11,267)
Amortization of debt issuance costs	11,411	5,635	498
Amortization of discounts on long-term debt	15,140	7,735	—
Stock-based compensation expense	25,957	33,352	6,676
Accretion expense	522	370	167
Depletion, depreciation and amortization expense	424,424	177,742	65,201
Exploration and abandonment expense	4,242	146	742
Changes in operating assets and liabilities:			
Accounts receivable	2,007	(57,218)	(31,655)
Prepaid expenses, inventory and other assets	6,923	(11,959)	(7,053)
Accounts payable, accrued liabilities and other current liabilities	8,488	34,087	24,509
Net cash provided by operating activities	756,389	504,014	147,015
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to crude oil and natural gas properties	(1,009,855)	(1,046,739)	(236,242)
Changes in working capital associated with oil and gas property additions	(100,802)	128,938	37,259
Acquisitions of crude oil and natural gas properties	(15,085)	(262,363)	(54,045)
Proceeds from sales of properties	—	—	3,366
Other property additions	(193)	(2,244)	(709)
Net cash used in investing activities	(1,125,935)	(1,182,408)	(250,371)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under Term Loan Credit Agreement, net of discount	1,170,000	—	—
Borrowings under Prior Credit Agreement	255,000	925,000	120,000
Proceeds from issuance of senior notes, net of discount	—	440,179	—
Repayments under Prior Credit Agreement	(525,000)	(755,000)	(20,000)
Repayments of 10.000% Senior Notes and 10.625% Senior Notes	(475,000)	—	—
Premium on extinguishment of debt	(4,457)	—	—
Proceeds from issuance of common stock	155,768	85,000	25,300
Proceeds from exercises of warrants	4,028	7,805	5,466
Proceeds from subscription receivable from exercises of warrants	—	—	3,596
Proceeds from exercises of stock options	148	120	1,573
Debt issuance costs	(28,444)	(17,128)	(2,169)
Stock offering costs	(5,371)	(339)	(2,463)
Dividends paid	(11,864)	(10,412)	(11,593)
Dividend equivalents paid	(1,251)	(1,196)	(1,037)
Net cash provided by financing activities	533,557	674,029	118,673
Net increase (decrease) in cash and cash equivalents	164,011	(4,365)	15,317
Cash and cash equivalents, beginning of period	30,504	34,869	19,552
Cash and cash equivalents, end of period	$ 194,515	$ 30,504	$ 34,869
Supplemental cash flow information:			
Cash paid for interest	$ 133,104	$ 24,268	$ 1,811
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of non-cash transactions:			
Stock issued for acquisitions	$ —	$ 264,982	$ —
Additions to asset retirement obligations	$ 6,048	$ 2,879	$ 1,844

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1. Organization and Nature of Operations

HighPeak Energy, Inc. ("HighPeak Energy" or the "Company,") is a Delaware corporation, formed in October 2019. HighPeak Energy's common stock and warrants are listed and traded on the Nasdaq Global Market (the "Nasdaq") under the ticker symbols "HPK" and "HPKEW," respectively. The Company is an independent crude oil and natural gas exploration and production company that explores for, develops and produces crude oil, NGL and natural gas in the Permian Basin in West Texas, more specifically, the Midland Basin primarily in Howard and Borden Counties. Our acreage is composed of two core areas, Flat Top primarily in the northern portion of Howard County extending into southern Borden County, southwest Scurry County and northwest Mitchell County and Signal Peak in the southern portion of Howard County.

NOTE 2. Basis of Presentation and Summary of Significant Accounting Policies

Presentation. The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). In the opinion of management, all adjustments, consisting of normal and recurring accruals considered necessary for a fair presentation, have been included. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2023, through the date of this Annual Report.

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries since their acquisition or formation. All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to prior period amounts to conform to the current period's presentation, which had an immaterial effect on the previously reported total assets, total liabilities, stockholders' equity, results of operations or cash flows.

Use of estimates in the preparation of consolidated financial statements. Preparation of the Company's consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of crude oil and natural gas properties is determined using estimates of proved crude oil, NGL and natural gas reserves and evaluations for impairment of proved and unproved crude oil and natural gas properties, in part, is determined using estimates of proved and risk adjusted probable and possible crude oil, NGL and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved, probable and possible reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, if needed, evaluations for impairment of proved crude oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves, commodity price outlooks and future undiscounted and discounted net cash flows. In addition, evaluations for impairment of unproved crude oil and natural gas properties on a project-by-project basis are also subject to numerous uncertainties including, among others, estimates of future recoverable reserves, results of exploration activities, commodity price outlooks, planned future sales or expirations of all or a portion of such projects. Other items subject to such estimates and assumptions include, but are not limited to, the carrying value of crude oil and natural gas properties, asset retirement obligations, equity-based compensation, fair value of derivatives, expected credit losses and estimates of income taxes. Actual results could differ from the estimates and assumptions utilized.

Cash and cash equivalents. The Company's cash and cash equivalents include depository accounts held by banks with original issuance maturities of 90 days or less. The Company's cash and cash equivalents are generally held in financial institutions in amounts that may exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. As of December 31, 2023 and 2022, the Company's accounts receivables primarily consist of amounts due from the sale of crude oil, NGL and natural gas of $82.5 million and $81.6 million, respectively, and are based on estimates of sales volumes and realized prices the Company anticipates it will receive, receivables related to settlements of derivative contracts of $4.5 million and $4.7 million, respectively, joint interest receivables of $4.4 million and $2.2 million, respectively, current U.S. federal income tax receivables of $3.2 million and $3.2 million, respectively, and zero and $4.9 million, respectively, related to receivables from electric power infrastructure installed throughout Flat Top by the Company for which it was reimbursed. The Company's share of crude oil, NGL and natural gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company's credit risk related to collecting accounts receivables is mitigated by using credit and other financial criteria to evaluate the credit standing of the entity obligated to make payment on the accounts receivable, and where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the counterparty or other credit support.

The Company adopted ASU 2016-13 and the subsequent applicable modifications to the rule on January 1, 2023. Accounts receivable are stated at amounts due from purchasers or joint interest owners, net of an allowance for expected losses as estimated by the Company when collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable from purchasers or joint interest owners outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance for each type of receivable by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for expected losses. As of December 31, 2023 and 2022, the Company had no allowance for credit losses related to accounts receivable and no allowance for doubtful accounts, respectively.

Concentration of credit risk. The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with significant purchasers. For the years ended December 31, 2023, 2022 and 2021, sales to the Company's largest purchaser accounted for approximately 82%, 88% and 94%, respectively, of the Company's total crude oil, NGL and natural gas sales revenues and for the year ended December 31, 2023, sales to the Company's second largest purchaser accounted for approximately 14% of the Company's total crude oil, NGL and natural gas revenues. The Company generally does not require collateral and does not believe the loss of these particular purchasers would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

Inventory. Inventory is comprised primarily of crude oil and natural gas drilling and completion or repair items such as pumps, tubing, casing, vessels, operating supplies and ordinary maintenance materials and parts. The materials and supplies inventory is primarily acquired for use in future drilling and completion or repair operations and is carried at the lower of cost or net realizable value, on a weighted average cost basis. Valuation allowances for materials and supplies inventories are recorded as reductions to the carrying values of the materials and supplies inventories in the Company's consolidated balance sheet and as charges to other expense in the consolidated statements of operations. The Company's materials and supplies inventory as of December 31, 2023 and 2022 is $7.3 million and $13.3 million, respectively, and the Company has not recognized any valuation allowance to date.

Prepaid expenses. Prepaid expenses are comprised primarily of prepaid insurance costs that will be amortized over the life of the policies, caliche that will be used on future locations and roads in our development areas, tubulars and proppant that the Company has prepaid the suppliers to guarantee their availability when needed for our current drilling program and prepaid agency fees and software maintenance fees that will be amortized over the life of the contracts. Prepaid expenses as of December 31, 2023 and 2022 are $1.0 million and $4.1 million, respectively.

Crude oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its crude oil and natural gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheet following the completion of drilling unless both of the following conditions are met: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predict the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and are being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the project has found sufficient proved reserves to sanction the project or is noncommercial and is charged to exploration and abandonment expense. See Note 6 for additional information.

The capitalized costs of proved properties are depleted using the unit-of-production method based on proved reserves for leasehold costs and proved developed reserves for drilling, completion and other crude oil and natural gas property costs. Costs of unproved leasehold costs are excluded from depletion until proved reserves are established or, if unsuccessful, impairment is determined.

Proceeds from the sales of individual properties are credited to proved or unproved crude oil and natural gas properties, as the case may be, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recorded until an entire amortization base is sold. However, gain or loss is recorded from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

The Company performs assessments of its long-lived assets to be held and used, including proved crude oil and natural gas properties accounted for under the successful efforts method of accounting, whenever changes in events or circumstances indicate that the carrying value of those assets may not be recoverable. If there is an indication the carrying value of the assets may not be recovered, an impairment loss is recognized if the sum of the expected future cash flows is less than the carrying amount of the assets. In these circumstances, the Company recognizes an impairment charge for the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets.

Unproved crude oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. These impairment assessments are affected by the estimates of future recoverable reserves, results of exploration activities, commodity price outlooks, planned future sales or expirations of all or a portion of such projects. If the estimated future net cash flows attributable to such projects are not expected to be sufficient to fully recover the costs invested in each project, the Company will recognize an impairment charge at that time.

Other property and equipment, net. Other property and equipment is recorded at cost. The carrying values of other property and equipment, net of accumulated depreciation of $904,000 and $696,000 as of December 31, 2023 and 2022, respectively, are as follows (in thousands):

	December 31,	
	2023	**2022**
Land	$ 2,139	$ 2,139
Transportation equipment	689	691
Buildings	530	544
Leasehold improvements	209	206
Field equipment	4	6
Furniture and fixtures	1	1
Total other property and equipment, net	$ 3,572	$ 3,587

Other property and equipment are depreciated over their estimated useful life on a straight-line basis. Land is not depreciated. Transportation equipment is generally depreciated over five years, buildings are generally depreciated over forty years, field equipment is generally depreciated over seven years and furniture and fixtures is generally depreciated over five years. Leasehold improvements are amortized over the lesser of their estimated useful lives or the underlying terms of the associated leases.

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such assets are considered to be impaired, the impairment to be recorded is measured by the amount by which the carrying amount of the asset exceeds its estimated fair value. The estimated fair value is determined using either a discounted future cash flow model or another appropriate fair value method.

Aid-in-construction assets. As of December 31, 2023 and 2022, the Company had aid-in-construction assets totaling $5.2 million and $6.1 million, respectively, included in other noncurrent assets. The Company has received and will continue to receive payments based on gross system throughput, including any third-party natural gas that is potentially tied into the Flat Top gathering system in the future. The contract calls for future aid-in-construction funding if expansions of the system are necessary as determined in the sole discretion of the Company.

Leases. The Company enters into leases for drilling rigs, storage tanks, equipment and buildings and recognizes lease expense on a straight-line basis over the lease term. Lease right-of-use assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As most of the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate, which is determined based on information available at the commencement date of a lease. Leases may include renewal, purchase or termination options that can extend or shorten the term of a lease. The exercise of those options is at the Company's sole discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with an initial term of 12 months or less are generally not recorded as lease right-of-use assets and liabilities. See Note 10 for additional information.

Current liabilities. Current liabilities as of December 31, 2023 and 2022 totaled approximately $287.4 million and $266.1 million, respectively, including current maturities of long-term debt, trade accounts payable, accrued capital expenditures, revenues and royalties payable, derivative liabilities and accruals for operating and general and administrative expenses, interest expense, operating leases, dividends and dividend equivalents and other miscellaneous items.

Debt issuance costs and original issue discount. The Company has paid a total of $48.1 million in debt issuance costs, $28.4 million of which was incurred during the year ended December 31, 2023 primarily related to the completion of the Term Loan Credit Agreement and Senior Credit Facility Agreement and amendments to the Prior Credit Agreement. Amortization based on the straight-line method over the terms of the Term Loan Credit Agreement, Senior Credit Facility Agreement, Prior Credit Agreement, 10.000% Senior Notes and 10.625% Senior Notes which approximates the effective interest method was $11.4 million, $5.6 million and $498,000 during the years ended December 31, 2023, 2022 and 2021, respectively. In addition, the Company realized a total of $64.8 million in original issue discounts on the issuance of its Term Loan Credit Agreement, 10.000% Senior Notes and 10.625% Senior Notes that is being amortized over the life of the agreements which approximates the effective interest method and was $15.1 million, $7.7 million and zero during the years ended December 31, 2023, 2022 and 2021, respectively. All unamortized debt issuance costs and discounts as of the termination of the Prior Credit Agreement and redemption of the 10.000% Senior Notes and 10.625% Senior Notes during September 2023 were charged to expense and included in loss on extinguishment of debt in the accompanying consolidated statements of operations. See Note 7 for more information. As of December 31, 2023 and 2022, the remaining net debt issuance costs and discounts related to the Term Loan Credit Agreement and Senior Credit Facility Agreement are netted against the outstanding long-term debt on the accompanying consolidated balance sheets.

Asset retirement obligations. The Company records a liability for the fair value of an asset retirement obligation in the period in which the associated asset is acquired or placed into service if a reasonable estimate of fair value can be made. Asset retirement obligations are generally capitalized as part of the carrying value of the long-lived asset to which it relates. Conditional asset retirement obligations meet the definition of liabilities and are recorded when incurred and when fair value can be reasonably estimated. See Note 8 for additional information.

Revenue recognition. The Company follows FASB ASC 606, "Revenue from Contracts with Customers," ("ASC 606") whereby the Company recognizes revenues from the sales of crude oil, NGL and natural gas to its purchasers and presents them disaggregated on the Company's consolidated statements of operations.

The Company enters into contracts with purchasers to sell its crude oil, NGL and natural gas production. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model prescribed in ASC 606. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the crude oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the crude oil and natural gas marketing contracts is typically received from the purchaser one to two months after the date of sale. As of December 31, 2023 and 2022, the Company had receivables related to contracts with purchasers of approximately $82.5 million and $81.6 million, respectively.

Crude Oil Contracts. The Company's crude oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the crude oil has been transferred to the purchaser. The crude oil produced is sold under contracts using market-based pricing which is then adjusted for the differentials based upon delivery location and crude oil quality. Since the differentials are incurred after the transfer of control of the crude oil, the differentials are included in crude oil sales on the consolidated statements of operations as they represent part of the transaction price of the contract.

Natural Gas Contracts. The majority of the Company's natural gas is sold at the lease location, which is generally when control of the natural gas has been transferred to the purchaser. The natural gas is sold under (i) percentage of proceeds processing contracts or (ii) a hybrid of percentage of proceeds and fee-based contracts. Under the majority of the Company's contracts, the purchaser gathers the natural gas in the field where it is produced and transports it to natural gas processing plants where NGL products are extracted. The NGL products and remaining residue natural gas are then sold by the purchaser. Under percentage of proceeds and hybrid percentage of proceeds and fee-based contracts, the Company receives a percentage of the value for the extracted liquids and the residue natural gas. Since control of the natural gas transfers upstream of the transportation and processing activities, revenue is recognized as the net amount received from the purchaser.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Derivatives. All the Company's derivatives are accounted for as non-hedge derivatives and are recorded at estimated fair value in the consolidated balance sheets. All changes in the fair values of its derivative contracts are recorded as gains or losses in the earnings of the periods in which they occur. The Company enters into derivatives under master netting arrangements, which, in an event of default, allows the Company to offset payables to and receivables from the defaulting counterparty. The Company classifies the fair value amounts of derivative assets and liabilities executed under master netting arrangements as net current or noncurrent derivative assets or net current or noncurrent derivative liabilities, whichever the case may be, by commodity and counterparty.

The Company's credit risk related to derivatives is a counterparties' failure to perform under derivative contracts owed to the Company. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 5 for additional information.

Income taxes. The provision for income taxes is determined using the asset and liability approach of accounting for income taxes. Under this approach, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the carrying amounts for income tax purposes and net operating loss and tax credit carryforwards. The amount of deferred taxes on these temporary differences is determined using the tax rates that are expected to apply to the period when the asset is realized or the liability is settled, as applicable, based on tax rates and laws in the respective tax jurisdiction enacted as of the balance sheet date.

The Company reviews its deferred tax assets for recoverability and establishes a valuation allowance based on projected future taxable income, applicable tax strategies and the expected timing of the reversals of existing temporary differences. A valuation allowance is provided when it is more likely than not (likelihood of greater than 50 percent) that some portion or all the deferred tax assets will not be realized. The Company has not established a valuation allowance as of December 31, 2023 and 2022.

Tax benefits from an uncertain tax positions are recognized only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recognized. See Note 13 for additional information.

Tax-related interest charges are recorded as interest expense and any tax-related penalties as other expense in the consolidated statements of operations of which there have been none to date.

The Company is also subject to Texas Margin Tax. The Company realized no current Texas Margin Tax in the accompanying consolidated financial statements as we do not anticipate owing any Texas Margin Tax for the periods presented.

Stock-based compensation. Stock-based compensation expense for stock option awards is measured at the grant date or modification date, as applicable, using the fair value of the award, and is recorded, net of forfeitures, on a straight-line basis over the requisite service period of the respective award. The fair value of stock option awards is determined on the grant date or modification date, as applicable, using a Black-Scholes option valuation model with the following inputs; (i) the grant date's closing stock price, (ii) the exercise price of the stock options, (iii) the expected term of the stock option, (iv) the estimated risk-free adjusted interest rate for the duration of the option's expected term, (v) the expected annual dividend yield on the underlying stock and (vi) the expected volatility over the option's expected term.

Stock-based compensation for restricted stock awarded to outside directors, employee members of the Board and certain other employees is measured at the grant date using the fair value of the award and is recognized on a straight-line basis over the requisite service period of the respective award.

Segments. Based on the Company's organizational structure, the Company has one operating segment, which is crude oil and natural gas development, exploration and production. In addition, the Company has a single, company-wide management team that allocates capital resources to maximize profitability and measures financial performance as a single enterprise.

Recently adopted accounting pronouncements. In June 2016, the FASB issued ASU 2016-13, "Financial Instruments – Credit Losses." This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investment in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. The Company adopted this update effective January 1, 2023. The adoption of this update did not have a material impact on the Company's financial position, results of operations or liquidity since it does not have a history of credit losses.

New accounting pronouncements not yet adopted. In December 2023, the FASB issued ASU 2023-09, "Income Taxes (Topic 740): Improvements to Income Tax Disclosures," which enhances the transparency and decision usefulness of income tax disclosures. The amendments address more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information. The ASU also includes certain other amendments to improve the effectiveness of income tax disclosures. The amendments in this ASU are effective for public business entities for annual periods beginning after December 15, 2024 on a prospective basis. Early adoption is permitted. The Company is currently evaluating the impact of the adoption of this guidance.

In November 2023, the FASB issued ASU 2023-07, "Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures." This ASU updates reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses and information used to assess segment performance. The amendments in this ASU are effective for public entities for fiscal years beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. The Company is still evaluating the effect of the adoption of this guidance.

The Company considers the applicability and the impact of all ASUs. ASUs were assessed and determined to be either not applicable, the effects of adoption are not expected to be material or are clarifications of ASUs previously disclosed.

NOTE 3. Acquisitions and Divestitures

Hannathon Acquisition. In June 2022, the Company closed the Hannathon Acquisition for total net consideration of $337.2 million after normal and customary closing adjustments, including 3,522,117 shares of HighPeak Energy common stock valued at $97.2 million at closing to acquire various crude oil and natural gas properties largely contiguous to its Signal Peak operating area in Howard County, including associated producing properties, water system infrastructure and in-field fluid gathering pipelines. The Hannathon Acquisition was accounted for as an asset acquisition as substantially all of the gross assets acquired are concentrated in a group of similar identifiable assets. The consideration paid was allocated to the individual assets acquired and liabilities assumed based on their relative fair values. All transaction costs associated with the Hannathon Acquisition were capitalized.

Alamo Acquisitions. In March and June 2022, the Company closed the Alamo Acquisitions in two separate deals for total net consideration of $156.1 million and $11.0 million, respectively, after normal and customary closing adjustments, including 6,960,000 and 371,517 shares of HighPeak Energy common stock valued at $156.6 million and $11.2 million, respectively, at closing to acquire various crude oil and natural gas properties contiguous to its Flat Top operating area in Borden county, including associated producing properties, water system infrastructure and in-field fluid gathering pipelines. The Alamo Acquisitions were accounted for as asset acquisitions as substantially all of the gross assets acquired are concentrated in a group of similar identifiable assets. The consideration paid was allocated to the individual assets acquired and liabilities assumed based on their relative fair values. All transaction costs associated with the Alamo Acquisitions were capitalized.

Other Acquisitions. During the years ended December 31, 2023 and 2022, the Company also incurred an additional $15.1 million and $23.0 million, respectively, in acquisition costs primarily to acquire various undeveloped crude oil and natural gas properties largely contiguous to its Signal Peak and Flat Top operating areas primarily in Howard, Borden, Mitchell and Scurry counties. During the year ended December 31, 2021, the Company incurred a total of $54.0 million in acquisition costs related to multiple bolt-on producing property acquisitions and lease acquisitions to acquire interests in non-operated producing wells and undeveloped acreage in and around the Company's existing properties.

Divestitures. During the year ended December 31, 2021, the Company realized net proceeds of $3.3 million, which reduced the Company's proved properties with no gain or loss recognized when it divested of 1 gross (0.2 net) non-operated horizontal well and acquired 4 gross (3.7 gross) operated vertical wells in a trade with another operator whereby the Company traded an approximate equal number of net mineral acres to increase its working interest in certain areas of Flat Top where it serves as operator and decrease its working interest in other areas of Flat Top where the other party serves as operator.

NOTE 4. Fair Value Measurements

The Company determines fair value based on the price that would be received from selling an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The three input levels of the fair value hierarchy are as follows:

- Level 1 – quoted prices for identical assets or liabilities in active markets.
- Level 2 – quoted prices for similar assets or liabilities in active markets; quoted prices for identical assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability (e.g., interest rates) and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3 – unobservable inputs for the asset or liability, typically reflecting management's estimate of assumptions that market participants would use in pricing the asset or liability. The fair values are therefore, determined using model-based techniques, including discounted cash flow models.

Assets and liabilities measured at fair value on a recurring basis. Assets and liabilities measured at fair value on a recurring basis as of December 31, 2023 and 2022 are as follows (in thousands):

	As of December 31, 2023			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Assets:				
Commodity price derivatives – current	$ —	$ 31,480	$ —	$ 31,480
Commodity price derivatives – noncurrent	—	16,059	—	16,059
Total assets	—	47,539	—	47,539
Liabilities:				
Commodity price derivatives – current	—	13,054	—	13,054
Commodity price derivatives – noncurrent	—	65	—	65
Total liabilities	—	13,119	—	13,119
Total recurring fair value measurements	$ —	$ 34,420	$ —	$ 34,420

	As of December 31, 2022			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Assets:				
Commodity price derivatives– current	$ —	$ 17	$ —	$ 17
Liabilities:				
Commodity price derivatives – current	—	16,702	—	16,702
Commodity price derivatives – noncurrent	—	691	—	691
Total liabilities	—	17,393	—	17,393
Total recurring fair value measurements	$ —	$ (17,376)	$ —	$ (17,376)

Commodity price derivatives. The Company's commodity price derivatives are currently made up of crude oil swap contracts, enhanced collars and deferred premium put options. The Company measures derivatives using an industry-standard pricing model that is provided by the counterparties. The inputs utilized in the third-party discounted cash flow and option-pricing models for valuing commodity price derivatives include forward prices for crude oil, contracted volumes, volatility factors and time to maturity, which are considered Level 2 inputs.

Assets and liabilities measured at fair value on a nonrecurring basis. Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. Specifically, (i) stock-based compensation is measured at fair value on the date of grant based on Level 1 inputs for restricted stock awards or Level 2 inputs for stock option awards based upon market data, and (ii) the estimates and fair value measurements used for the evaluation of proved property for potential impairment using Level 3 inputs based upon market conditions in the area. The Company assesses the recoverability of the carrying amount of certain assets and liabilities whenever events or changes in circumstances indicate the carrying amount of an asset or liability may not be recoverable. These assets and liabilities can include inventories, proved and unproved crude oil and natural gas properties and other long-lived assets that are written down to fair value when they are impaired or held for sale. The Company did not record any impairments to proved or unproved crude oil and natural gas properties for the periods presented in the accompanying consolidated financial statements.

Financial instruments not carried at fair value. Carrying values and fair values of financial instruments that are not carried at fair value in the consolidating balance sheets are as follows (in thousands):

	As of December 31, 2023		As of December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Liabilities:				
Long-term debt:				
10.625% Senior Notes (a)	$ —	$ —	$ 250,000	$ 250,000
10.000% Senior Notes (a)	$ —	$ —	$ 225,000	$ 225,000

(a) Fair value is determined using Level 2 inputs. The Company's senior unsecured notes are quoted, but not actively traded, on major exchanges; therefore, fair value is based on periodic values as quoted on major exchanges. See Note 7 for additional information.

The Company has other financial instruments consisting primarily of cash and cash equivalents, accounts receivable, accounts payable, long-term debt (specifically the Term Loan Credit Agreement, Senior Credit Facility Agreement and the Prior Credit Agreement), and other current assets and liabilities that approximate fair value due to the nature of the instrument and their relatively short maturities.

NOTE 5. Derivative Financial Instruments

The Company primarily utilizes commodity swap contracts, deferred premium put options and enhanced collars to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's capital budgeting and expenditure plans, (iii) protect the Company's commitments under the Term Loan Credit Agreement and Senior Credit Facility Agreement and (iv) support the payment of contractual obligations.

The following table summarizes the effect of derivative instruments on the Company's consolidated statements of operations (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Noncash gain (loss) on derivative instruments, net	$ 51,796	$ (1,909)	$ (15,467)
Cash paid on settlement of derivative instruments, net	(24,194)	(58,096)	(11,267)
Gain (loss) on derivative instruments, net	$ 27,602	$ (60,005)	$ (26,734)

Crude oil production derivatives. The Company sells its crude oil production at the lease and the sales contracts governing such crude oil production are tied directly to, or are correlated with, NYMEX WTI crude oil prices. As such, the Company uses NYMEX WTI derivative contracts to manage future crude oil price volatility.

The Company's outstanding crude oil derivative instruments as of December 31, 2023 and the weighted average crude oil prices and premiums payable per barrel for those contracts are as follows:

					Swaps	Enhanced Collars & Deferred Premium Puts		
Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Price per Bbl	Floor or Strike Price per Bbl	Ceiling Price per Bbl	Deferred Premium Payable per Bbl
Crude Oil:								
Jan - Mar	2024	Swap	4,000	WTI	$ 84.00	$ —	$ —	$ —
Jan - Mar	2024	Collar	6,000	WTI	$ —	$ 80.00	$ 100.00	$ 3.50
Jan - Mar	2024	Put	20,000	WTI	$ —	$ 66.44	$ —	$ 5.00
Apr - Jun	2024	Swap	4,000	WTI	$ 84.00	$ —	$ —	$ —
Apr - Jun	2024	Collar	5,500	WTI	$ —	$ 69.73	$ 95.00	$ 0.61
Apr - Jun	2024	Put	14,000	WTI	$ —	$ 60.41	$ —	$ 5.00
Jul - Sep	2024	Swap	4,000	WTI	$ 84.00	$ —	$ —	$ —
Jul - Sep	2024	Collar	1,500	WTI	$ —	$ 69.00	$ 95.00	$ 0.85
Jul - Sep	2024	Put	14,000	WTI	$ —	$ 60.41	$ —	$ 5.00
Oct - Dec	2024	Swap	5,500	WTI	$ 76.37	$ —	$ —	$ —
Oct - Dec	2024	Collar	10,600	WTI	$ —	$ 65.68	$ 90.32	$ 1.85
Oct - Dec	2024	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00
Jan - Mar	2025	Swap	5,500	WTI	$ 76.37	$ —	$ —	$ —
Jan - Mar	2025	Collar	8,000	WTI	$ —	$ 65.00	$ 90.00	$ 2.12
Jan - Mar	2025	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00
Apr - Jun	2025	Swap	5,500	WTI	$ 76.37	$ —	$ —	$ —
Apr - Jun	2025	Collar	7,000	WTI	$ —	$ 65.00	$ 90.08	$ 2.28
Apr - Jun	2025	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00
Jul - Sep	2025	Swap	3,000	WTI	$ 75.85	$ —	$ —	$ —
Jul - Sep	2025	Collar	7,000	WTI	$ —	$ 65.00	$ 90.08	$ 2.28
Jul - Sep	2025	Put	2,000	WTI	$ —	$ 58.00	$ —	$ 5.00

The Company uses credit and other financial criteria to evaluate the credit standings of, and to select, counterparties to its derivative financial instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative financial instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

Net derivative assets associated with the Company's open commodity derivative instruments by counterparty are as follows (in thousands):

	As of December 31, 2023
Mercuria Energy Trading SA	$ 19,520
Wells Fargo Bank, National Association	7,570
Fifth Third Bank, National Association	5,004
Macquarie Bank Limited	2,326
	$ 34,420

NOTE 6. Exploratory/Extension Well Costs

The Company capitalizes exploratory/extension wells and project costs until a determination is made that the well or project has either found proved reserves, is impaired or is sold. The Company's capitalized exploratory/extension well and project costs are included in proved properties in the consolidated balance sheets. If the exploratory/extension well or project is determined to be impaired, the impaired costs are charged to exploration and abandonments expense.

The changes in capitalized exploratory/extension well costs are as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Beginning capitalized exploratory/extension well costs	$ 186,427	$ 28,076	$ 32,592
Additions to exploratory/extension well costs	527,502	655,294	189,859
Reclassification to proved properties	(673,041)	(496,943)	(194,375)
Exploratory/extension well costs charged to exploration and abandonment expense	—	—	—
Ending capitalized exploratory/extension well costs	$ 40,888	$ 186,427	$ 28,076

All capitalized exploratory/extension well costs have been capitalized for less than one year based on the date of drilling.

NOTE 7. Long-Term Debt

The components of long-term debt, including the effects of discounts and debt issuance costs, are as follows (in thousands):

	December 31,	
	2023	2022
Term Loan Credit Agreement due 2026	$ 1,200,000	$ —
Senior Credit Facility Agreement due 2026	—	—
Prior Credit Agreement	—	270,000
10.625% Senior Notes	—	250,000
10.000% Senior Notes	—	225,000
Discounts, net (a)	(27,062)	(27,086)
Debt issuance costs, net (b)	(22,639)	(13,565)
Total debt	1,150,299	704,349
Less current maturities of long-term debt	(120,000)	—
Long-term debt, net	$ 1,030,299	$ 704,349

(a) Discounts as of December 31, 2023 and 2022 consisted of $30.0 million and $34.8 million, respectively, in discounts less accumulated amortization of $2.9 million and $7.7 million, respectively.

(b) Debt issuance costs as of December 31, 2023 and 2022 consisted of \$25.0 million and \$19.7 million, respectively, in costs less accumulated amortization of \$2.4 million and \$6.1 million, respectively.

Term Loan Credit Agreement. On September 12, 2023, the Company entered into a Term Loan Credit Agreement with Texas Capital Bank ("Texas Capital") as the administrative agent and Chambers Energy Management, LP ("Chambers") as collateral agent and lenders from time-to-time party thereto to establish a term loan ("Term Loan Credit Agreement") totaling $1.2 billion in borrowings, less a 2.5% original issue discount of $30.0 million at closing and customary debt issuance costs which totaled approximately $24.0 million. The Term Loan Credit Agreement matures on September 30, 2026. Loans under the Term Loan Credit Agreement bear interest at a rate per annum equal to the Adjusted Term SOFR (as defined in the Term Loan Credit Agreement) plus an applicable margin of 7.50%. To the extent that a payment default exists and is continuing, at the election of the Required Lenders (as defined in the Term Loan Credit Agreement) under the Term Loan Credit Agreement, all amounts outstanding under the Term Loan Credit Agreement will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto. The Company is able to repay any amounts borrowed prior to the maturity date, subject to a concurrent payment of (i) the Make-Whole Amount (as defined in the Term Loan Credit Agreement) for any optional prepayment prior to the date 18 months after the closing date, (ii) 1.00% of the principal amount being repaid for any optional prepayment on or after the date 18 months after the closing date but prior to the date 24 months after the closing date and (iii) without any premium for any optional prepayment on or after the date that is 24 months after the closing date. The Term Loan Credit Agreement is guaranteed by the Company and certain of its subsidiaries and is secured by a first lien security interest in substantially all assets of the Company and certain of its subsidiaries.

The Term Loan Credit Agreement also contains certain financial covenants, including (i) an asset coverage ratio that may not be less than 1.50 to 1.00 as of the last day of any fiscal quarter and (ii) a total net leverage ratio that may not exceed 2.00 to 1.00 as of the last day of any fiscal quarter. Additionally, the Term Loan Credit Agreement contains additional restrictive covenants that limit the ability of the Company and its restricted subsidiaries to, among other things, incur additional indebtedness (with such exceptions including, among other things, a super priority revolving credit facility limited to $100 million), incur additional liens, make investments and loans, enter into mergers and acquisitions, materially increase dividends and other payments, enter into certain hedging transactions, sell assets, engage in transactions with affiliates and make certain capital expenditures based on the Company's total net leverage ratio.

The Term Loan Credit Agreement contains customary mandatory prepayments, including quarterly installments of $30.0 million in aggregate principal amount beginning March 31, 2024, the prepayment of gross proceeds from an incurred indebtedness other than Permitted Indebtedness (as defined in the Term Loan Credit Agreement), the prepayment of net cash proceeds for asset sales and hedge terminations in excess of $20.0 million within one calendar year, and prepayments of Excess Cash Flow (as defined in the Term Loan Credit Agreement) beginning with the fiscal quarter ending March 31, 2024. In addition, the Term Loan Credit Agreement is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the collateral agent or the majority lenders may accelerate any amounts outstanding and terminate lender commitments.

Collateral Agency Agreement. On September 12, 2023, the Company entered into a collateral agency agreement (the "Collateral Agency Agreement") among the Company, Texas Capital, as collateral agent, Chambers, as term representative, and Mercuria Energy Trading SA, as first-out representative prior to giving effect to that certain Collateral Agency Joinder – Additional First-Out Debt, dated as of November 1, 2023 and Fifth Third Bank, National Association as first-out representative after giving effect to that certain Collateral Agency Joinder – Additional First-Out Debt, dated as of November 1, 2023.

The Collateral Agency Agreement provides for the appointment of Texas Capital, as collateral agent, for the present and future holders of the first lien obligations (including the obligations of the Company and certain of its subsidiaries under the Term Loan Credit Agreement) to receive, hold, administer and distribute the collateral that is at any time delivered to Texas Capital or the subject of the Security Documents (as defined in the Collateral Agency Agreement) and to enforce the Security Documents and all interests, rights, powers and remedies of Texas Capital with respect thereto or thereunder and the proceeds thereof.

Senior Credit Facility Agreement. On November 1, 2023, the Company entered into a credit agreement with Fifth Third Bank, National Association ("Fifth Third") as the administrative agent and as the collateral agent and a number of banks included in the syndicate to establish a senior revolving credit facility ("Senior Credit Facility Agreement") that matures on September 30, 2026. The Senior Credit Facility Agreement has aggregate maximum commitments of $100.0 million with current commitments of $75.0 million. Loans under the Senior Credit Facility Agreement bear interest at either the Adjusted Term SOFR (as defined in the Senior Credit Facility Agreement) or the Base Rate (as defined in the Senior Credit Facility Agreement) at the Company's option, plus an applicable margin ranging (i) for Adjusted Term SOFR loans, from 4.00% to 5.00%, and (ii) for Base Rate loans, from 3.00% to 4.00%, in each case calculated based on the ratio at such time of the outstanding principal loan amounts to the aggregate amount of lenders' commitments. To the extent that a payment default exists and is continuing, at the election of the Required Lenders (as defined in the Senior Credit Facility Agreement) under the Senior Credit Facility Agreement, all amounts outstanding under the Senior Credit Facility Agreement will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto. The Company is able to repay any amounts borrowed prior to the maturity date without premium or penalty. The Senior Credit Facility Agreement is guaranteed by the Company and certain of its subsidiaries and is secured by a first lien security interest in substantially all assets of the Company and certain of its subsidiaries.

Prior Credit Agreement. In December 2020, the Company entered into a credit agreement with Fifth Third as the administrative agent and sole lender to establish a revolving credit facility (the "Prior Credit Agreement") that was set to mature on June 17, 2024. In June 2021, the Company entered into the First Amendment to, among other things, (i) complete the semi-annual borrowing base redetermination process which increased the borrowing base from $40.0 million to $125.0 million and (ii) modify the terms of the Prior Credit Agreement to increase the aggregate elected commitments from $20.0 million to $125.0 million. A syndicate of banks joined the credit facility at differing levels of commitments with Fifth Third remaining the administrative agent. In October 2021, the Company entered into the Second Amendment to, among other things, (i) complete a semi-annual borrowing base redetermination process, which increased the borrowing base from $125.0 million to $195.0 million and (ii) modify the terms of the Prior Credit Agreement to increase the aggregate elected commitments from $125.0 million to $195.0 million. In February 2022, the Company entered into the Third Amendment to, among other things, (i) reduce the borrowing base from $195.0 million to $138.8 million, (ii) modify the terms of the Prior Credit Agreement to reduce the aggregate elected commitments from $195.0 million to $138.8 million, (iii) update the maturity date to a springing maturity date, which will cause the Prior Credit Agreement to mature on October 1, 2023 if the 10.000% Senior Notes are not redeemed or refinanced by that date or the terms of the 10.000% Senior Notes have not been amended to extend the scheduled repayment thereof to no earlier than October 1, 2024, (iv) allow the Company to redeem the 10.000% Senior Notes with proceeds of a refinancing, with proceeds of an equity offering or with cash, in each case, subject to certain customary conditions and (v) replace the USD LIBOR rates with Term SOFR rates.

In June 2022, the Company entered into the Fourth Amendment to, among other things, (i) increase (a) the aggregate elected commitments to $400.0 million, (b) the borrowing base to $400.0 million and (c) the maximum credit amount to $1.5 billion, (ii) increase the excess cash threshold to $75.0 million, (iii) modify the affirmative hedging requirement so that if total debt to EBITDAX is greater than 1.25 to 1.00 but less than or equal to 1.75 to 1.00, notional volumes covering the first 24 months following the measurement date shall be hedged in an amount equal to not less than 25% of the projected production and if total debt to EBITDAX is greater than 1.75 to 1.00, notional volumes covering the first 24 months following the measurement date shall be hedged in an amount equal to not less than 50% of the projection production and (iv) increase the number of banks included in the syndicate at differing levels of commitments, with Fifth Third remaining the administrative agent.

In October 2022, the Company entered into the Fifth Amendment to, among other things, (i) increase the elected commitments to $525 million and the borrowing base to $550 million, (ii) require an additional borrowing base redetermination on or about December 1, 2022, (iii) modify the permitted dividends and distributions conditions such that minimum availability under the credit facility must be 25% percent (as opposed to 30% before giving effect to the Fifth Amendment) and (iv) appoint Wells Fargo Bank, National Association ("Wells Fargo") as the new administrative agent to replace Fifth Third. In addition, in connection with the Fifth Amendment, to the extent the Company incurs any additional specified unsecured senior, senior subordinated or subordinated future indebtedness in an aggregate amount of up to $250.0 million before June 30, 2023, the Company's obligation to reduce the borrowing base by an amount equal to 25% of the principal amount of such additional future indebtedness shall be waived. In connection with the Fifth Amendment, the lenders waived two events of default existing with the Prior Credit Agreement, as it existed prior to giving effect to the Fifth Amendment, related to entering into and maintaining certain minimum hedges as of the fiscal quarters ending June 30, 2022 and September 30, 2022 and complying with the required current ratio as of the fiscal quarter ending September 30, 2022. In October 2022, the Company entered into the Sixth Amendment to, among other things, (i) change the period to 120 days following the maturity date for which there can be no scheduled principal payments, mandatory redemption or maturity date for the 10.000% Senior Notes and the Specified Senior Notes, (ii) clarify that the Specified Senior Notes are subject to the restriction on the voluntary redemption by the Company of certain specified additional debt, including the 10.000% Senior Notes, (iii) add a permitted lien basket in connection with the escrow account to be opened in connection with the Specified Senior Notes and (iv) provide for an exception for the restriction on mandatory redemptions of the Specified Senior Notes in connection with the special mandatory redemption provided for with respect to the Specified Senior Notes.

In December 2022, the Company entered into the Seventh Amendment to, among other things, increase the amount of Specified Senior Notes from $225.0 million to $250.0 million. In March 2023, the Company entered into the Eighth Amendment to, among other things, (a) increase the borrowing base to $700.0 million, (b) add an aggregate elected commitments concept at an initial amount of $575.0 million, (c) provide that the applicable margin shall be determined in reference to such aggregate elected commitments (as opposed to being determined in reference to the borrowing base before giving effect to the Eighth Amendment), (d) modify the permitted dividends and distributions conditions such that minimum availability under the credit facility must be 25% of such aggregate elected commitments (as opposed to the borrowing base before giving effect to the Eighth Amendment), (e) permit quarterly dividends and distributions in an amount not to exceed $4.0 million provided that there is no default and that after giving effect thereto and any concurrent borrowing, the Company is in pro forma compliance with its financial covenants, (f) require the Company, on or before June 30, 2023, to redeem or refinance the 10.000% Senior Notes, allocate a portion of its cash flow that will retire the 10.000% Senior Notes on or before November 30, 2023 or amend the terms of the 10.000% Senior Notes to extend the scheduled repayment thereof to no earlier than February 15, 2025, (g) permit the redemption of Specified Additional Debt (defined in the Prior Credit Agreement to mean any unsecured senior, senior subordinated or subordinated Debt of the Borrower incurred after the Effective Date and any refinancing of such Debt, including without limitation, the 10.000% Senior Notes; provided that any such Debt may be refinanced only to the extent that the aggregate principal amount of such refinanced Debt does not result in an increase in the principal amount thereof plus amounts to fund any original issue discount or upfront fees relating thereto plus amounts to fund accrued interest, fees, expenses and premiums, with all Capitalized terms defined in such Prior Credit Agreement) with the proceeds of Loans if pre-approved by all Lenders provided that there is no default and that after giving effect thereto, the Company is in pro forma compliance with its financial covenants and (h) add Texas Capital Bank as a Lender.

In July 2023, the Company entered into the Ninth Amendment to, among other things, provide for (i) a waiver of the minimum current ratio covenant for the fiscal quarter ended June 30, 2023 under the Prior Credit Agreement, (ii) a waiver of the failure to subject one or more certain accounts to an Account Control Agreement within the period provided in the Prior Credit Agreement, (iii) a postponement of the April 2023 borrowing base redetermination until September 2023, (iv) a postponement of the date on which the Company was previously obligated thereunder to either extend the maturity of the 10.000% Senior Notes due February 2024, redeem or refinance the 10.000% Senior Notes or allocate a portion of the Company's cash flow satisfactory to the Administrative Agent and the Majority Lenders that will retire the 10.000% Senior Notes on or before November 30, 2023 to September 1, 2023 or such later date as agreed to in writing by the Majority Lenders in their reasonable discretion, (v) certain pricing increases and additional minimum hedging requirements, (vi) an additional requirement to deliver a 13-week cash flow forecast on a weekly basis through completion of the September 2023 borrowing base redetermination and (vii) a temporary restriction on borrowing further amounts under the Prior Credit Agreement until the Company has received at least $95 million of net proceeds from the sales of the Company's equity securities, which has been subsequently satisfied and the restriction no longer applies.

In connection with the entry into the aforementioned Term Loan Credit Agreement, the Prior Credit Agreement was terminated, all outstanding obligations for principal, interest and fees were paid off in full, and all liens securing such obligations and guarantees of such obligations and securing any letter of credit or hedging obligations (other than those novated pursuant to the terms of the Term Loan Credit Agreement) permitted by the Prior Credit Agreement to be secured by such liens were released. In addition, unamortized debt issuance costs as of the termination date of $2.7 million were charged to expense and included in the accompanying consolidated statements of operations in loss on extinguishment of debt.

10.000% Senior Notes. In February 2022, the Company issued $225.0 million aggregate principal amount of its 10.000% Senior Notes due 2024 ("10.000% Senior Notes"), which were set to mature on February 15, 2024. The Company received proceeds of $202.9 million, net of $22.1 million of issuance costs and discounts. The net proceeds were used to pay down the balance of the Prior Credit Agreement to zero at closing and to fund our ongoing capital development program with subsequent draws on the Prior Credit Agreement. Interest on the 10.000% Senior Notes was payable on February 15 and August 15 of each year. In connection with the aforementioned Term Loan Credit Agreement, the 10.000% Senior Notes were redeemed at a redemption price of 100% of the principal amount thereof plus accrued and unpaid interest and fees. In addition, unamortized discounts and debt issuance costs as of the redemption date of $3.2 million and $1.5 million, respectively, were charged to expense and included in the accompanying consolidated statements of operations in loss on extinguishment of debt.

10.625% Senior Notes. In November 2022 and December 2022, the Company issued $225.0 million and $25.0 million, respectively, under separate indentures, of its 10.625% Senior Notes due 2024 ("10.625% Senior Notes"), which were set to mature on November 15, 2024. The Company received proceeds of $223.7 million, net of $26.3 million of issuance costs and discounts. The net proceeds were used to reduce the outstanding balance of the Prior Credit Agreement at closing and for general corporate purposes. Interest on the 10.625% Senior Notes was payable on May 15 and November 15 of each year. In addition, the Company paid additional interest of $8.3 million in June 2023 in accordance with the indentures whereby if the Company did not receive a rating increase by June 30, 2023, it was required to pay said additional interest that is included in interest expense during the nine months ended September 30, 2023. In connection with the aforementioned Term Loan Credit Agreement, the 10.625% Senior Notes were redeemed at a redemption price of 100% of the principal amount thereof plus accrued and unpaid interest and fees, plus the applicable premium calculated as $4.5 million, which was the present value at September 14, 2023 of all required interest payments due on the 10.625% Senior Notes through November 15, 2023. In addition, unamortized discounts and debt issuance costs as of the redemption date of $11.7 million and $3.7 million, respectively, were charged to expense and included in the accompanying consolidated statements of operations in loss on extinguishment of debt.

The Term Loan Credit Agreement and the Senior Credit Facility Agreement have hedging requirements to which the Company adheres.

NOTE 8. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

Asset retirement obligations activity is as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Beginning asset retirement obligations	$ 7,502	$ 4,260	$ 2,293
Liabilities incurred from new wells	445	573	980
Liabilities assumed in acquisitions	2,638	3,219	981
Liabilities divested	(81)	—	(6)
Dispositions	—	—	(25)
Revision of estimates (a)	2,219	(920)	(130)
Accretion of discount	522	370	167
Ending asset retirement obligations	$ 13,245	$ 7,502	$ 4,260

(a) The revisions to the Company's asset retirement obligation estimates are primarily due to changes in the ultimate expected useful lives of the properties.

As of December 31, 2023 and 2022, all asset retirement obligations are considered noncurrent and classified as such in the accompanying consolidated balance sheets.

NOTE 9. Incentive Plans

401(k) Plan. The HighPeak Energy Employees, Inc 401(k) Plan (the "401(k) Plan") is a defined contribution plan established under Section 401 of the Internal Revenue Code of 1986, as amended (the "Code"). All regular full-time and part-time employees of the Company are eligible to participate in the 401(k) Plan after three continuous months of employment with the Company. Participants may contribute up to 80 percent of their annual base salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by the Company in amounts equal to 100 percent of a participant's contributions to the 401(k) Plan up to four percent of the participant's annual base salary (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances at their eligibility date. During the years ended December 31, 2023, 2022 and 2021, the Company contributed $218,000, $358,000 and $227,000 to the 401(k) Plan, respectively.

Long-Term Incentive Plan. The Company's Second Amended & Restated Long Term Incentive Plan ("LTIP") provides for the grant of stock options, restricted stock, stock awards, dividend equivalents, cash awards and substitute awards to officers, employees, directors and consultants of the Company. The number of shares available for grant pursuant to awards under the LTIP as of December 31, 2023 and 2022 are as follows:

	December 31,	
	2023	2022
Approved and authorized shares	16,414,015	14,340,324
Shares subject to awards issued under plan	(15,759,791)	(13,769,191)
Shares available for future grant	654,224	571,133

Stock options. Stock option awards were granted to employees on August 24, 2020, November 4, 2021, May 4, 2022, August 15, 2022 and July 21, 2023. Stock-based compensation expense related to the Company's stock option awards for the years ended December 31, 2023 and 2022 was $11.0 million and $18.1 million, respectively, and as of December 31, 2023 and 2022 there was $145,000 and $1.1 million, respectively, of unrecognized stock-based compensation expense related to unvested stock option awards. The unrecognized compensation expense will be recognized on a straight-line basis over the remaining vesting periods of the awards, which is a period of less than one year. The 1,949,000 stock options granted in July 2023 were 100% vested upon grant on July 21, 2023. However, to encourage long-term alignment with the Company stockholders, the stock options are not exercisable until the earlier of (i) August 31, 2026, (ii) upon a change in control or (iii) upon the death or disability of the grantee.

The Company estimates the fair values of stock options granted on the grant date using a Black-Scholes option valuation model, which requires the Company to make several assumptions. The expected term of options granted was determined based on the simplified method of the midpoint between the vesting dates and the contractual term of the options. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the option at the date of grant and the volatility was based on the volatility of either an index of exploration and production crude oil and natural gas companies or on a peer group of companies with similar characteristics of the Company on the date of grant since the Company had minimal or did not have any trading history. More detailed stock options activity and details are as follows:

	Stock Options		Average Exercise Price	Remaining Term in Years		Intrinsic Value (in thousands)
Outstanding at December 31, 2021	9,983,727	$	10.19	8.7	$	44,395
Awards granted	1,564,500	$	25.09			
Exercised	(12,000)	$	10.00			
Forfeitures	(18,999)	$	18.66			
Outstanding at December 31, 2022	11,517,228	$	12.20	7.9	$	128,429
Awards granted	1,949,000		10.50			
Exercised	(11,834)	$	12.52			
Forfeitures	(5,333)	$	24.83			
Outstanding at December 31, 2023	13,449,061	$	11.95	6.3	$	47,672
Vested at December 31, 2022	11,304,747	$	12.02	7.9	$	127,591
Exercisable at December 31, 2022	11,304,747	$	12.02	7.9	$	127,591
Vested at December 31, 2023	13,387,074	$	11.88	6.3	$	47,672
Exercisable at December 31, 2023	11,438,074	$	12.12	6.9	$	40,383

Restricted stock issued to employee members of the Board and certain employees. A total of 1,500,500 shares of restricted stock was approved by the Board to be granted to certain employee members of the Board of the Company on November 4, 2021, which vest on the three-year anniversary of such grant assuming the employees remain in his or her position as of the anniversary date. Therefore, stock-based compensation expense of $7.2 million, $7.2 million and $1.2 million was recognized during the years ended December 31, 2023, 2022 and 2021, respectively, and the remaining $6.0 million as of December 31, 2023 will be recognized over the remaining restricted period, which was based upon the closing price of the stock on the date of the restricted stock issuance. The Board also cancelled the previously issued equity-based liability bonuses and approved a total of 600,000 shares of restricted stock to be granted to certain employees of the Company on June 1, 2022, which vest on November 4, 2024, assuming the employees remain in his or her position as of that date and cancelled certain contractual equity-based bonuses to such employees. Therefore, stock-based compensation expense of $7.0 million, $7.3 million and $488,000 was recognized during the years ended December 31, 2023, 2022 and 2021, respectively, and the remaining $5.9 million as of December 31, 2023 will be recognized over the remaining restricted period, which was based upon the closing price of the stock on the date of the restricted stock issuance.

Stock issued to outside directors. A total of 58,767 shares of restricted stock was approved by the Board to be granted to the outside directors of the Company on June 1, 2023, which will vest at the next annual meeting, assuming the Board members maintain their positions on the Board. Therefore, stock-based compensation expense of $442,000 was recognized during the year ended December 31, 2023 and the remaining $316,000 will be recognized between January and May 2024, which was based upon the closing price of the stock on the date of the restricted stock issuance. In addition, a total of 21,184 shares of restricted stock was approved by the Board to be granted to the outside directors of the Company on June 1, 2022, which vested during the second quarter of 2022. Therefore, stock-based compensation expense of $305,000, $427,000 was recognized during the years ended December 31, 2023 and 2022, respectively, which was based upon the closing price of the stock on the date of the restricted stock issuance. Finally, a total of 67,779 shares of restricted stock was approved by the Board to be granted to the outside directors of the Company on June 1, 2021, which vested in January 2022. Therefore, stock-based compensation expense of $284,000 and $398,000 was recognized during the years ended December 31, 2022 and 2021, respectively, which was based upon the closing price of the stock on the date of the restricted stock issuance.

NOTE 10. Commitments and Contingencies

Leases. The Company follows ASC Topic 842, “Leases” to account for its operating and finance leases. Therefore, as of December 31, 2023, the Company had right-of-use assets totaling $510,000 included in other noncurrent assets and operating lease liabilities totaling $528,000, all of which are included in current liabilities, and as of December 31, 2022 the Company had right-of-use assets totaling $333,000 included in other noncurrent assets and operating lease liabilities totaling $343,000, included in other current liabilities on the accompanying consolidated balance sheets. The Company does not currently have any finance right-of-use leases. Maturities of the operating lease obligations are as follows (in thousands):

	December 31, 2023
2024	$ 552
Less present value discount	(24)
Present value of lease liabilities	$ 528

Legal actions. From time to time, the Company may be a party to various proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company records reserves for contingencies when information available indicates that a loss is probable, and the amount of the loss can be reasonably estimated.

Indemnifications. The Company has agreed to indemnify its directors, officers and certain employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Environmental. Environmental expenditures that relate to an existing condition caused by past operations and have no future economic benefits are expensed. Environmental expenditures that extend the life of the related property or mitigate or prevent future environmental contamination are capitalized. Liabilities for expenditures that will not qualify for capitalization are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are undiscounted unless the timing of cash payments for the liability is fixed or reliably determinable. Environmental liabilities normally involve estimates that are subject to revision until settlement or remediation occurs.

Crude oil delivery commitments. In May 2021, the Company entered into a crude oil marketing contract with DK Trading & Supply, LLC ("Delek") as the purchaser and DKL Permian Gathering, LLC ("DKL") as the gatherer and transporter. The contract includes the Company's current and future crude oil production from the majority of its horizontal wells in Flat Top where DKL is continually constructing a crude oil gathering system and custody transfer meters to most of the Company's central tank batteries. The contract contains a minimum volume commitment commencing October 2021 based on the gross barrels delivered at the Company's central tank battery facilities and is 5,000 Bopd for the first year, 7,500 Bopd for the second year and 10,000 Bopd for the remaining eight years of the contract. However, the Company has the ability under the contract to cumulatively bank excess volumes delivered to offset future minimum volume commitments. For the period from October 1, 2021 to December 31, 2023, the Company has delivered approximately 29,600 Bopd under the contract which is approximately 72 percent of the contracted volume for the life of the contract. The monetary commitment for the remaining 9.5 MMBbl as of December 31, 2023, if the Company never delivers any additional volumes under the agreement, is approximately $7.8 million.

Natural gas purchasing replacement contract. In May 2021, the Company entered into a replacement natural gas purchase contract with WTG Gas Processing, L.P. ("WTG") as the gatherer, processor and purchaser of the Company's current and future gross natural gas production in Flat Top. The replacement contract provides the Company with improved natural gas and NGL pricing and required WTG to expand its current low-pressure gathering system, which eliminates the need for in-field compression in Flat Top to accommodate the Company's increased natural gas production volumes based on the current plan of development. The Company provides WTG with certain aid-in-construction payments to be reimbursed over time based on throughput through the system. The replacement contract does not contain any minimum volume commitments.

Power contracts. In June 2022, the Company entered into a contract with TXU Energy Retail Company LLC ("TXU") to provide a block of electric power at an attractive variable rate, which fluctuates based on the usage by the Company through May 31, 2032. In conjunction with this contract, the Company currently has a $3.9 million letter of credit issued in lieu of a deposit to TXU that is cancellable at the end of the contract term.

Sand commitments. The Company is party to an amended agreement whereby it has agreed to purchase at least 1.6 million tons of sand over a two-year period beginning July 1, 2022. There are stipulations in the agreement that reduce this commitment should there be a downturn in crude oil prices. As of December 31, 2023, the Company has purchased approximately 1.2 million tons of sand under the contract. However, generally if the Company never takes delivery of any additional sand under the agreement, the monetary commitment that remains as of December 31, 2023 is approximately $9.5 million.

NOTE 11. Related Party Transactions

Underwritten Equity Offering. In connection with the Company's underwritten equity offering in July 2023, certain of the Company's existing stockholders, John Paul DeJoria Family Trust and Jack Hightower, the Company's Chairman and Chief Executive Officer, and entities and individuals associated with them, purchased an aggregate of approximately 10 million shares of common stock in the offering at the public offering price per share. In connection therewith, the Underwriter received a reduced underwriting discount on such shares purchased by these persons or entities compared with other shares sold to the public in the offering.

Water Treatment. In September 2021, the Company entered into a contract with Pilot Exploration, Inc., ("Pilot"), whose President and CEO was an outside director of the Company, to deploy Pilot's proprietary water treatment technology in the Company's Flat Top area to treat up to 25,000 barrels of produced water per day that can be reused in the Company's completion operations or sold to third parties for their completion operations. This contract was set to expire on March 1, 2022; however, it was extended to October 1, 2022 based on the early results of the project. During the year ended December 31, 2022, the Company paid $2.0 million to Pilot for such services.

In May 2022, the Company entered into an agreement with Pilot to utilize Pilot's proprietary water treatment technology in the Company's Flat Top area to treat produced water such that it can be reused in the Company's completion operations or sold to third parties for their completion operations. During the one-year term of the agreement, beginning on October 1, 2022, the Company agreed to a minimum volume commitment of 29.2 million barrels of produced water while maintaining the ability to bank excess produced water processed each month toward the minimum volume commitment. During the years ended December 31, 2023 and 2022, the Company paid $1.5 million and $1.6 million, respectively, to Pilot for such services. In April 2023, the Company terminated the contract with Pilot in exchange for $6.5 million that was charged to other expense in the accompanying consolidated statements of operations during the year ended December 31, 2023.

Private Investment in Public Equity. On August 22 and 23, 2022, HighPeak Energy entered into multiple Subscription Agreements (the "Subscription Agreements") with certain accredited investors (collectively, the "Investors") pursuant to which, among other things, the Investors agreed to subscribe for and purchase, and the Company agreed to issue and sell to the Investors, an aggregate 2,855,162 newly issued shares of the Company's common stock at a price per share of $21.61 (as determined by the 5-day volume weighted average trading price per share for the five trading days immediately prior to (and excluding) August 22, 2022), for aggregate gross proceeds of approximately $61.7 million. The Company used the proceeds of the Private Placement for general corporate purposes. The transactions contemplated by the Subscription Agreements closed in multiple closings on or about September 2, 2022, subject to customary closing conditions.

As part of the private placement, certain related persons of the Company participated as investors, and such participation was approved by the Board pursuant to and in accordance with the terms of the Related Party Transactions Policy adopted by the Board on August 21, 2020. Specifically, Messrs. Jack Hightower (the Company's Chief Executive Officer), Michael Hollis (the Company's President), Steven Tholen (the Company's Chief Financial Officer), Rodney Woodard (the Company's Chief Operating Officer) and John Paul DeJoria as trustee for the John Paul DeJoria Family Trust (a greater than ten percent (10%) holder of the Company's outstanding common stock) entered into Subscription Agreements to purchase 462,749, 46,276, 9,255, 23,138 and 2,313,744 shares of common stock, respectively, in each case on substantially the same terms as other investors in the private placement. In addition, each Subscription Agreement with an investor other than Messrs. Hightower and DeJoria (each of which has existing registration rights with respect to the Company's securities) provides for customary registration rights with respect to the shares issued thereunder, including the right to have such shares registered for resale on a "shelf" registration statement.

NOTE 12. Major Customers

Delek accounted for approximately 82%, 88% and 94% of the Company's revenues during the years ended December 31, 2023, 2022 and 2021, respectively. In addition, Energy Transfer Crude Marketing, LLC ("ETC") accounted for approximately 14% of the Company's revenues during the year ended December 31, 2023. Based on the current demand for crude oil and natural gas and the availability of other purchasers, management believes the loss of these major purchasers would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

NOTE 13. Income Taxes

Enactment of the Inflation Reduction Act of 2022. On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 ("IRA 2022"). The IRA 2022, among other tax provisions, imposes a 15 percent corporate alternative minimum tax on corporations with book financial statement income in excess of $1.0 billion, effective for tax years beginning after December 31, 2022. The IRA 2022 also establishes a one percent excise tax on stock repurchases made by publicly traded U.S. corporations, effective for stock repurchases in excess of an annual limit of $1.0 million after December 31, 2022. The IRA 2022 did not impact the Company's current year tax provision or the Company's consolidated financial statements. The Company is evaluating the accounting and disclosure implications of the IRA 2022 on its future filings.

The Company's income tax expense attributable to income from operations consisted of the following (in thousands):

	Year Ended December 31,		
	2023	**2022**	**2021**
Current income tax expense:			
Federal	$ —	$ —	$ —
State	—	—	—
Total current income tax expense	—	—	—
Deferred income tax expense:			
Federal	63,002	73,026	15,084
State	2,903	2,335	1,820
Deferred income tax expense	65,905	75,361	16,904
Total income tax expense	$ 65,905	$ 75,361	$ 16,904

The reconciliation between the income tax expense computed by multiplying pre-tax income by the U.S. federal statutory rate and the reported amounts of income tax expense is as follows (in thousands, except rate):

	Year Ended December 31, 2023	Year Ended December 31, 2022	Year Ended December 31, 2021
Income tax expense at U.S. federal statutory rate	$ 59,172	$ 65,565	$ 15,217
Limited tax benefit due to wage and stock-based compensation	3,811	7,362	(51)
State deferred income taxes	2,903	2,335	1,730
Other	19	99	8
Income tax expense	$ 65,905	$ 75,361	$ 16,904
Effective income tax rate	23.4%	24.1%	23.3%

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities were as follows as of December 31, 2023 and 2022 (in thousands):

	December 31, 2023	December 31, 2022
Deferred tax assets:		
Interest expense limitations	$ 41,352	$ 10,623
Net operating loss carryforwards	13,503	5,496
Stock-based compensation	6,332	4,102
Other	36	32
Unrecognized derivative losses, net	—	3,752
Less: Valuation allowance	—	—
Deferred tax assets	61,223	24,005
Deferred tax liabilities:		
Crude oil and natural gas properties, principally due to differences in basis and depreciation and the deduction of intangible drilling costs for tax purposes	(250,859)	(155,169)
Unrecognized derivative gains, net	(7,432)	—
Deferred tax liabilities	(258,291)	(155,169)
Net deferred tax liabilities	$ (197,068)	$ (131,164)

The effective income tax rate differs from the U.S. statutory rate of 21 percent primarily due to reversing a portion of its deferred tax asset related to stock-based compensation, deferred state income taxes and other permanent differences between GAAP income and taxable income.

As required by ASC Topic 740, "Income Taxes," ("ASC 740") the Company uses reasonable judgments and makes estimates and assumptions related to evaluating the probability of uncertain tax positions. The Company bases its estimates and assumptions on the potential liability related to an assessment of whether the income tax position will "more likely than not" be sustained in an income tax audit. Based on that analysis, the Company believes the Company has not taken any material uncertain tax positions, and therefore has not recorded an income tax liability related to uncertain tax positions. However, if actual results materially differ, the Company's effective income tax rate and cash flows could be affected in the period of discovery or resolution. The Company also reviews the estimates and assumptions used in evaluating the probability of realizing the future benefits of the Company's deferred tax assets and records a valuation allowance when the Company believes that a portion or all the deferred tax assets may not be realized. If the Company is unable to realize the expected future benefits of its deferred tax assets, the Company is required to provide a valuation allowance. The Company uses its history and experience, overall profitability, future management plans, tax planning strategies, and current economic information to evaluate the amount of valuation allowance to record. As of December 31, 2023 and 2022, the Company had not recorded a valuation allowance for deferred tax assets arising from its operations because the Company believed they met the "more likely than not" criteria as defined by the recognition and measurement provisions of ASC 740. The Company reversed a portion of its deferred tax asset related to stock-based compensation based on the assumption that the tax deduction will be subject to IRC Section 162(m) limits when the stock options are exercised and the restricted stock vests. IRC Section 162(m) limits compensation deductions to $1.0 million per year for certain Company executives. This resulted in a $3.4 million reduction in the deferred tax asset and reduced the amount of income tax expense realized during the year ended December 31, 2022.

The Company is also subject to Texas Margin Tax. The Company realized no current Texas Margin Tax in the accompanying consolidated financial statements as we do not anticipate owing any Texas Margin Tax for 2023, 2022 or 2021. However, the Company has recognized a net deferred Texas Margin Tax liability of $7.1 million and $4.1 million as of December 31, 2023 and 2022, respectively, in the accompanying consolidated financial statements.

NOTE 14. Earnings Per Share

The Company uses the two-class method of calculating earnings per share because certain of the Company's stock-based awards qualify as participating securities.

The Company's basic earnings per share attributable to common stockholders is computed as (i) net income as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings per share attributable to common stockholders is computed as (i) basic earnings attributable to common stockholders, (ii) plus reallocation of participating earnings (iii) divided by weighted average diluted common shares outstanding.

The following table reconciles the Company's earnings from operations and earnings attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings per share amounts for the years ended December 31, 2023, 2022 and 2021 under the two-class method (in thousands):

	Year Ended December 31,		
	2023	**2022**	**2021**
Net income as reported	$ 215,866	$ 236,854	$ 55,559
Participating basic earnings (a)	(21,890)	(22,991)	(4,674)
Basic earnings attributable to common stockholders	193,976	213,863	50,885
Reallocation of participating earnings	334	401	58
Diluted net income attributable to common stockholders	$ 194,310	$ 214,264	$ 50,943
Basic weighted average shares outstanding	117,956	104,738	93,127
Dilutive warrants and unvested stock options	2,905	4,304	145
Dilutive unvested restricted stock	2,159	2,122	1,500
Diluted weighted average shares outstanding	123,020	111,164	94,772

(a) Vested stock options represent participating securities because they participate in dividend equivalents with the common equity holders of the Company. Participating earnings represent the distributed and undistributed earnings of the Company attributable to the participating securities. Certain unvested restricted stock awarded to outside directors, employee members of the Board and certain employees do not represent participating securities because, while they participate in dividends with the common equity holders of the Company, the dividends associated with such unvested restricted stock are forfeitable in connection with the forfeitability of the underlying restricted stock. Unvested stock options do not represent participating securities because, while they participate in dividend equivalents with the common equity holders of the Company, the dividend equivalents associated with unvested stock options are forfeitable in connection with the forfeitability of the underlying stock options.

The calculation for weighted average shares reflects shares outstanding over the reporting period based on the actual number of days the shares were outstanding.

NOTE 15. Stockholders' Equity

Issuance of Common Stock. In July 2023, the Company issued 14,835,000 shares of its common stock in a public offering discussed below. The remaining 420,896 shares of HighPeak Energy common stock issued during the year ended December 31, 2023 were the result of warrants (350,295 shares) being exercised, the issuance of restricted stock (58,767 shares) to outside directors and stock options (11,834 shares) being exercised. On March 25, 2022, June 21, 2022 and June 27, 2022, respectively, the Company issued 6,960,000, 371,517 and 3,522,117 shares of HighPeak Energy common stock related to the aforementioned crude oil and natural gas property acquisitions. On June 1, 2022, the Company issued 21,184 and 600,000 shares of restricted stock to outside directors and certain employees, respectively. On September 2, 2022, the Company closed an aggregate $85.0 million private placement of 3,933,376 newly issued shares of HighPeak Energy common stock at a price per share of $21.61 as determined by the 5-day volume weighted average closing price per share for the five days immediately prior to (and excluding) August 22, 2022. The initial closings occurred on August 22, 2022, with the final closings on September 2, 2022. The remaining 982,648 shares of HighPeak Energy common stock issued during the year ended December 31, 2022 were the result of warrants (970,648 shares) and stock options (12,000 shares) being exercised. On June 1, 2021 and November 4, 2021, the Company issued 67,779 and 1,500,500 shares of restricted stock to outside directors and employee members of the Board, respectively. In October 2022, the Company issued 2,530,000 shares of its common stock in a public offering discussed below. The remaining 708,341 shares of HighPeak Energy common stock issued during the year ended December 31, 2021 were the result of warrants (554,073 shares) and stock options (154,268 shares) being exercised.

Public Offerings of Common Stock. On July 19, 2023, the Company completed the offering of 14,835,000 shares of its common stock, at a price to the public of $10.50 per share, pursuant to a Registration Statement on Form S-3 (File No. 333-261706) filed on December 17, 2021. The net proceeds to the Company from the offering, after deducting the underwriting discounts and commissions and other offering expenses, were approximately $150.4 million. On October 25, 2021, the Company completed the offering of 2,530,000 shares of its common stock, at a price to the public of $10.00 per share, pursuant to a Registration Statement on Form S-1 (File No. 333-258853) filed on October 19, 2021 and a Registration Statement on Form S-1MEF (File No. 333-260394) filed with the SEC on October 20, 2021. The net proceeds to the Company from the offering, after deducting the underwriting discounts and commissions and other offering expenses, were approximately $22.8 million.

Dividends and dividend equivalents. In October 2023, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $3.2 million in dividends being paid on November 22, 2023. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $348,000 in November 2023 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures. In addition, the Company accrued an additional combined $54,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

In July 2023, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $3.2 million in dividends being paid on August 25, 2023. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $334,000 in August 2023 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures. In addition, the Company accrued an additional combined $54,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

In April 2023, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.8 million in dividends being paid on May 25, 2023. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $286,000 in May 2023 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures. In addition, the Company accrued an additional combined $53,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

In January 2023, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.8 million in dividends being paid on February 24, 2023. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $282,000 in February 2023 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures. In addition, the Company accrued an additional combined $53,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

In October 2022, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.8 million in dividends being paid on November 23, 2022. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $288,000 in November 2022 and accrued a dividend equivalent per share to all unvested stock option holders which is payable upon vesting, assuming no forfeitures. In addition, the Company will accrue an additional combined $53,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

In July 2022, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.7 million in dividends being paid on August 25, 2022. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $481,000 in August 2022 and accrued a dividend equivalent per share to all unvested stock option holders which is payable upon vesting, assuming no forfeitures. In addition, the Company will accrue an additional combined $53,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

In April 2022, the Board declared a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.6 million in dividends being paid on May 25, 2022. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $214,000 in May 2022 and accrued a dividend equivalent per share to all unvested stock option holders which is payable upon vesting, assuming no forfeitures. In addition, the Company will accrue an additional combined $53,000 in dividends on the restricted stock issued to management directors and certain employees that will be payable upon vesting.

In January 2022, the Board approved a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.4 million in dividends being paid on February 25, 2022. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $214,000 in February 2022 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures. In addition, the Company accrued an additional combined $53,000 in dividends on the restricted stock issued to management directors and certain employees that will be payable upon vesting.

In September 2021, the Board approved a quarterly dividend of $0.025 per share of common stock outstanding which resulted in a total of $2.3 million in dividends being paid on October 25, 2021. In addition, under terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $207,000 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures.

In July 2021, the Board approved a quarterly dividend of $0.025 and a special dividend of $0.075 per share of common stock outstanding which resulted in a total of $9.3 million in dividends being paid on July 26, 2021. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $830,000 and accrued a dividend equivalent per share to all unvested stock option holders which was payable upon vesting, assuming no forfeitures.

Outstanding Securities. At December 31, 2023 and 2022, the Company had 128,420,923 and 113,165,027 shares of common stock outstanding, respectively, and 7,934,977 and 8,285,272 warrants outstanding, respectively, with an exercise price of $11.50 per share that expire on August 21, 2025.

NOTE 16. Subsequent Events

Derivative Financial Instruments. In January 2024, the Company entered into fixed price basis swaps for the spread between the Cushing crude oil price and the Midland WTI crude oil price. The weighted average differential represents the amount of premium to the Cushing, Oklahoma crude oil price for the notional volumes covered by the basis swap contracts as shown below.

					Swaps	
Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Weighted Average Differential per Bbl	
Crude Oil:						
Jan - Mar	2024	Basis Swap	16,484	Argus WTI Midland	$	1.12
Apr - Jun	2024	Basis Swap	25,000	Argus WTI Midland	$	1.12
Jul - Sep	2024	Basis Swap	25,000	Argus WTI Midland	$	1.12
Oct - Dec	2024	Basis Swap	25,000	Argus WTI Midland	$	1.12

Share Repurchase Program. In February 2024, the Board approved a repurchase program of up to $75 million of the Company's common stock. The approval grants HighPeak's management the authority to repurchase shares opportunistically in the open market from time to time, through block trades, in privately negotiated transactions or by such other means which comply with applicable state and federal laws. This is the Company's first authorization for a stock repurchase program since its founding.

The Company intends to fund the repurchases from available working capital, cash provided from operations and borrowings under its Senior Credit Facility Agreement. The timing, number and value of shares repurchased under the program will be at the discretion of management and the Board of Directors and will depend on a number of factors, including general market and economic conditions, business conditions, the trading price of the Company's common stock, the nature of other investment opportunities available to the Company and compliance with the Company's debt and other agreements. The stock repurchase program does not obligate HighPeak to acquire any particular dollar amount or number of shares of its common stock and the stock repurchase program may be suspended from time to time, modified, extended or discontinued by the Company's Board of Directors. The stock repurchase program authority will expire December 31, 2024.

Dividends and dividend equivalents. In February 2024, the Board approved a quarterly dividend of $0.04 per share of common stock outstanding which resulted in a total of $5.1 million in dividends being paid on March 25, 2024. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $536,000 in March 2024 and will accrue a dividend equivalent per share to all unvested stock option holders which is payable upon vesting, assuming no forfeitures. In addition, the Company will accrue an additional combined $86,000 in dividends on the restricted stock issued to directors, management directors and certain employees that will be payable upon vesting.

NOTE 17 – Supplemental Crude Oil and Natural Gas Disclosures (Unaudited)

The Company only has one reportable operating segment, which is crude oil and natural gas development, exploration and production in the U.S.

Net Capitalized Costs

The following table reflects the capitalized costs of crude oil and natural gas properties and the related accumulated depletion (in thousands):

	December 31, 2023	December 31, 2022
Proved properties	$ 3,338,107	$ 2,270,236
Unproved properties	72,715	114,665
Total capitalized costs	3,410,822	2,384,901
Less: accumulated depletion	(684,179)	(259,962)
Net capitalized costs	$ 2,726,643	$ 2,124,939

Cost Incurred in Crude Oil and Natural Gas Property Acquisition, Exploration and Development

The following table reflects costs incurred in crude oil and natural gas property acquisition, development and exploratory activities (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Acquisition costs:			
Proved properties	$ 3,308	$ 352,791	$ 33,253
Unproved properties	11,777	174,554	20,792
Total acquisition costs	15,085	527,345	54,045
Exploration costs	527,502	655,433	190,346
Development costs	481,528	391,298	45,852
Crude oil and natural gas expenditures	1,024,115	1,574,076	290,243
Asset retirement obligations, net	6,048	2,879	1,844
Total costs incurred	$ 1,030,163	$ 1,576,955	$ 292,087

Results of Operations for Crude Oil, NGL and Natural Gas Producing Activities

The following table reflects the Company's results of operations for crude oil, NGL and natural gas producing activities (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Crude oil, NGL and natural gas sales	$ 1,111,293	$ 755,686	$ 220,124
Lease operating expenses	145,362	69,599	25,053
Production and ad valorem taxes	58,472	38,440	10,746
Exploration and abandonment expense	5,234	1,149	1,549
Depletion, depreciation and amortization expense	424,424	177,742	65,201
Accretion of discount on asset retirement obligations	522	370	167
Income tax expense	100,229	98,361	24,656
Results of operations from crude oil and natural gas production activities	$ 377,050	$ 370,025	$ 92,752

Crude Oil, NGL and Natural Gas Reserves

Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first day of the month spot prices prior to the end of the reporting period. These prices as of December 31, 2023, 2022 and 2021 were $78.22, $93.67 and $66.56 per barrel for crude oil and NGL and $2.637, $6.358 and $3.598 per MMBtu for natural gas, respectively. The estimated realized prices used in computing the Company's reserves as of December 31, 2023 were as follows: (i) $78.13 per barrel of crude oil, (ii) $17.33 per barrel of NGL, and (iii) $0.198 per Mcf of natural gas. The estimated realized prices used in computing the Company's reserves as of December 31, 2022 were as follows: (i) $94.59 per barrel of crude oil, (ii) $36.69 per barrel of NGL, and (iii) $4.871 per Mcf of natural gas. The estimated realized prices used in computing the Company's reserves as of December 31, 2021 were as follows: (i) $66.10 per barrel of crude oil, (ii) $29.76 per barrel of NGL, and (iii) $0.786 per Mcf of natural gas. All prices are net of adjustments for regional basis differentials, treating costs, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity adjustments.

The proved reserve estimates as of December 31, 2023, 2022 and 2021 were prepared by Cawley, Gillespie & Associates, Inc. ("CG&A"), independent reserve engineers, and reflect the Company's current development plans. All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of "reasonable certainty" be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond the Company's control, such as reservoir performance, prices, economic conditions, and government restrictions. In addition, results of drilling, testing, and production subsequent to the date of an estimate may justify revision of that estimate.

Reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. Estimating quantities of proved crude oil and natural gas reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based upon, economic factors, such as crude oil and natural gas prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating PUD reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, the Company's reserve estimates are inherently imprecise.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from crude oil and natural gas properties the Company owns declines as reserves are depleted. Except to the extent the Company conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the Company's proved reserves will decline as reserves are produced.

The following table reflects changes in proved reserves during the periods indicated:

	Crude Oil (MBbl)	NGL (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Proved Reserves on December 31, 2020	19,032	2,160	7,939	22,515
Extensions and discoveries	36,867	4,845	19,529	44,967
Purchase of reserves-in-place	973	631	2,910	2,089
Sales of minerals-in-place	(238)	(44)	(139)	(305)
Revisions of previous estimates	(1,807)	10	842	(1,657)
Production	(3,002)	(224)	(1,020)	(3,396)
Proved Reserves on December 31, 2021	51,825	7,378	30,061	64,213
Extensions and discoveries	47,677	6,162	24,887	57,987
Purchase of reserves-in-place	13,031	3,467	14,448	18,906
Revisions of previous estimates	(6,155)	(1,817)	(7,435)	(9,211)
Production	(7,562)	(821)	(3,323)	(8,937)
Proved Reserves on December 31, 2022	98,816	14,369	58,638	122,958
Extensions and discoveries	54,137	6,456	27,330	65,148
Purchase of reserves-in-place	89	47	208	171
Sales of reserves-in-place	(1,171)	(127)	(531)	(1,387)
Revisions of previous estimates	(18,432)	898	8,644	(16,093)
Production	(13,885)	(1,547)	(7,218)	(16,635)
Proved Reserves on December 31, 2023	119,554	20,096	87,071	154,162

On December 31, 2023, the Company had approximately 154,162 MBoe of proved reserves. For the year ended December 31, 2023, extensions and discoveries increased proved reserves by 65,148 MBoe as a result of; (i) drilling 63 gross (56.4 net) exploratory/extension wells that were on production as of December 31, 2023, (ii) 7 gross (6.6 net) exploratory/extension wells that were in the final stages of completion as of December 31, 2023, and (iii) the addition of 117 gross (102.4 net) PUDs. The Company also acquired 171 MBoe of reserves as part of its acquisition activities and divested of 1,387 MBoe of reserves in a farm out to another operator in return for a carried interest during the year ended December 31, 2023. Downward revisions of previous estimates of 16,093 MBoe for the year ended December 31, 2023 were the result of negative revisions of approximately 13,729 MBoe primarily due to technical revisions attributable to decreased well performance and adjustments to our estimates, approximately 1,775 MBoe primarily related to decreases in crude oil, NGL and natural gas realized prices and approximately 589 MBoe primarily due to increased forecasted operating expenses. The aforementioned net increase in proved reserves was partially offset by 16,635 MBoe in production during the year ended December 31, 2023. The Company's current development plan reflects allocation of capital with a focus on efficiencies, recoveries and rates of return.

On December 31, 2022, the Company had approximately 122,958 MBoe of proved reserves. For the year ended December 31, 2022, extensions and discoveries increased proved reserves by 57,987 MBoe as a result of: (i) drilling 37 gross (32.1 net) exploratory/extension wells that were on production as of December 31, 2022, (ii) 16 gross (14.8 net) exploratory/extension wells that were in the final stages of completion as of December 31, 2022, and (iii) the addition of 80 gross (75.2 net) PUDs. The Company also acquired 18,906 MBoe of reserves as part of its acquisition activities during the year ended December 31, 2022. Downward revisions of previous estimates of 9,211 MBoe for the year ended December 31, 2022 were primarily the result of negative revisions of 10,418 MBoe due to technical revisions attributable to decreased well performance and adjustments to our PUD estimates, partially offset by positive revisions of approximately 1,116 MBoe related to increases in crude oil, NGL and natural gas realized prices and positive revisions of approximately 91 MBoe primarily due to increased forecasted operating expenses. The aforementioned net increase in proved reserves was partially offset by 8,937 MBoe in production during the year ended December 31, 2022. The Company's current development plan reflects allocation of capital with a focus on efficiencies, recoveries and rates of return.

On December 31, 2021, the Company had approximately 64,213 MBoe of proved reserves. For the year ended December 31, 2021, extensions and discoveries increased proved reserves by 44,967 MBoe as a result of: (i) drilling 22 gross (17.8 net) exploratory wells that were on production as of December 31, 2021, (ii) 15 gross (11.0 net) exploratory wells that were in the final stages of completion as of December 31, 2021, and (iii) the addition of 53 gross (41.5 net) PUDs. The Company also acquired 2,089 MBoe of reserves as part of its acquisition activities and sold assets with proved reserves totaling 305 MBoe during the year ended December 31, 2021 in an acreage trade with an industry partner. Downward revisions of previous estimates of 1,657 MBoe for the year ended December 31, 2021 were primarily the result of: (i) negative revisions of 2,529 MBoe due to technical revisions attributable to decreased well performance and adjustments to our PUD estimates, (ii) negative revisions of approximately 85 MBoe primarily due to increased forecasted operating expenses and (iii) partially offset by positive revisions of approximately 957 MBoe related to increases in crude oil, NGL and natural gas realized prices. The aforementioned net increase in proved reserves was partially offset by 3,396 MBoe in production during the year ended December 31, 2021. The Company's current development plan reflects allocation of capital with a focus on efficiencies, recoveries and rates of return.

The following table sets forth the Company's estimated quantities of proved developed and proved undeveloped crude oil, NGL and natural gas reserves:

	December 31,		
	2023	2022	2021
Proved Developed Reserves (1)			
Crude oil (MBbl)	58,631	47,845	22,610
NGL (MBbl)	12,183	7,968	3,540
Natural gas (MMcf)	52,671	32,669	14,611
Total (MBoe)	79,593	61,258	28,585
Proved Undeveloped Reserves			
Crude oil (MBbl)	60,923	50,971	29,215
NGL (MBbl)	7,913	6,401	3,838
Natural gas (MMcf)	34,400	25,969	15,450
Total (MBoe)	74,569	61,700	35,628
Total Proved Reserves			
Crude oil (MBbl)	119,554	98,816	51,825
NGL (MBbl)	20,096	14,369	7,378
Natural gas (MMcf)	87,071	58,638	30,061
Total (MBoe)	154,162	122,958	64,213

(1) As of December 31, 2023, 2022 and 2021 and 2020, proved developed reserves includes proved developed non-producing reserves of 4,598, 7,417, 6,884 and 4,517 MBbl of crude oil, 534, 927, 793 and 517 MBbl of NGL and 1,889, 3,641, 3,222 and 1,912 MMcf of natural gas, respectively.

On December 31, 2023, the Company's estimated PUD reserves were approximately 74,569 MBoe, a 12,869 MBoe increase over the reserve estimate at December 31, 2022 of 61,700 MBoe. The following table includes the changes in PUD reserves for 2023 (in MBoe):

Beginning proved undeveloped reserves on December 31, 2022	61,700
Undeveloped reserves transferred to proved developed reserves	(25,955)
Extensions and discoveries	42,440
Sales of reserves-in-place	(1,387)
Revisions	(2,229)
Ending proved undeveloped reserves on December 31, 2023	74,569

Standardized Measure of Discounted Future Net Cash Flows

The following table reflects the Company's standardized measure of discounted future net cash flows relating from its proved crude oil, natural gas and NGL reserves (in thousands):

	December 31,		
	2023	2022	2021
Future cash inflows	$ 9,706,290	$ 10,159,310	$ 3,668,535
Future production costs	(2,869,377)	(2,289,852)	(824,865)
Future development costs (1)	(1,568,033)	(983,732)	(432,370)
Future income tax expense	(680,894)	(1,102,156)	(431,737)
Future net cash flows	4,587,986	5,783,570	1,979,563
Discount to present value at 10% annual rate	(1,980,282)	(2,367,062)	(860,754)
Standardized measure of discounted future net cash flows (1)	$ 2,607,704	$ 3,416,508	$ 1,118,809

The following table reflects the principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Standardized measure of discounted future net cash flows, beginning of year	$ 3,416,508	$ 1,118,809	$ 222,192

Sales of crude oil and natural gas, net of production costs	(907,459)	(647,647)	(184,325)
Extensions and discoveries, net of future development costs (1)	1,202,674	1,785,822	987,689
Net changes in prices and production costs	(1,404,147)	909,053	272,889
Changes in estimated future development costs (1)	(37,820)	(23,647)	(13,551)
Purchases of minerals-in-place	4,344	499,478	31,353
Sales of reserves-in-place	(25,069)	—	(3,067)
Revisions of previous quantity estimates	(390,282)	(354,868)	(40,466)
Accretion of discount	395,656	134,338	23,419
Net changes in income taxes	266,579	(315,478)	(212,574)
Net changes in timing of production and other	86,720	310,648	35,250
Standardized measure of discounted future net cash flows, end of year (1)	$ 2,607,704	$ 3,416,508	$ 1,118,809

(1) The standardized measure of discounted future net cash flows reflects, within the category for future development costs, all estimated future costs that will be incurred to settle our asset retirement obligations, including costs for dismantlement, restoration, and abandonment of the existing wells (including both active and inactive wells on leases and future proved undeveloped locations), in each case in compliance with FASB ASC 932-235-50-36.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, HighPeak Energy has evaluated, under the supervision and with the participation of the Company's management, including HighPeak Energy's principal executive officer and principal financial officer, the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the fiscal year covered by this Annual Report. Based on such evaluation, HighPeak Energy's principal executive officer and principal financial officer have concluded that as of such date, its disclosure controls and procedures were effective. The Company's disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by it in reports that it files under the Exchange Act is accumulated and communicated to management, including the Company's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC.

Changes in Internal Control over Financial Reporting

There have been no changes to the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Management is responsible for designing, implementing, and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act.

As required by Rule 13a-15 under the Exchange Act, management, with the participation of our principal executive and principal financial officers, assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2023, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management believes that the Company's internal control over financial reporting was effective as of December 31, 2023.

ITEM 9B. OTHER INFORMATION

Trading Plans

None of our directors or executive officers adopted or terminated a Rule 10b5-1 trading arrangement or adopted or terminated a non-Rule 10b5-1 trading arrangement (as defined in Item 408(c) of Regulation S-K) during the quarter ended December 31, 2023.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2023.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in HighPeak Energy's Definitive Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required in response to this item will be set forth in HighPeak Energy’s Definitive Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required in response to this item will be set forth in HighPeak Energy's Definitive Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is Weaver and Tidwell, L.L.P., Fort Worth, TX, PCAOB ID No. 410.

The information required in response to this item will be set forth in HighPeak Energy's Definitive Proxy Statement, to be filed within 120 days after the end of the fiscal year covered by this Annual Report and is incorporated herein by reference.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements are included in "Item 8. Financial Statements and Supplementary Data":

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets
Consolidated Statements of Operations
Consolidated Statements of Changes in Stockholders' Equity
Consolidated Statements of Cash Flows
Notes to Consolidated Financial Statements
Unaudited Supplementary Data

(b) Exhibits

The exhibits to this Annual Report required to be filed pursuant to Item 15(b) are listed below.

(c) Financial Statement Schedules

Financial statement schedules have been omitted because they either are not required, not applicable, or the information required to be presented is included in the Company's consolidated financial statements and related notes.

Exhibits

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of February 15, 2022, by and among HighPeak Energy, Inc., HighPeak Energy Assets, LLC, Alamo Borden County II, LLC, Alamo Borden County III, LLC and Alamo Borden County IV, LLC (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on June 23, 2022).
2.2	Put/Call Agreement, dated as of February 15, 2022, by and among HighPeak Energy, Inc. HighPeak Energy Assets, LLC, Alamo Frac Holdings, LLC, Alamo Exploration and Production, LLC, Crocket Operating LLC, Alamo Borden County II, LLC, Alamo Borden County III, LLC, Alamo Borden County IV, LLC and the other parties signatory thereto (incorporated by reference to Exhibit 2.3 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on June 23, 2022).
2.3	Purchase and Sale Agreement, dated as of April 26, 2022, by and among HighPeak Energy, Inc., HighPeak Energy Assets, LLC, Hannathon Petroleum, LLC and other sellers party thereto (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on June 30, 2022).

2.4 Purchase and Sale Agreement, dated as of June 3, 2022, by and among HighPeak Energy Assets, LLC and Alamo Borden County 1, LLC (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on June 23, 2022).

3.1 Second Amended and Restated Certificate of Incorporation of HighPeak Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on June 2, 2023).

3.2	Amended and Restated Bylaws of HighPeak Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (File No. 001-39464) filed with the SEC on November 9, 2020).
4.1	Registration Rights Agreement, dated as of August 21, 2020, by and among HighPeak Energy, Inc., HighPeak Pure Acquisition, LLC, HighPeak Energy, LP, HighPeak Energy II, LP, HighPeak Energy III, LP and certain other security holders named therein (incorporated by reference to Exhibit 4.4 to the Company’s Current Report on Form 8-K (File No. 001-39464) filed with the SEC on August 27, 2020).
4.2	Stockholders’ Agreement, dated as of August 21, 2020, by and among HighPeak Energy, Inc., HighPeak Pure Acquisition, LLC, HighPeak Energy, LP, HighPeak Energy II, LP, HighPeak Energy III, LP, Jack Hightower and certain directors of Pure Acquisition Corp. (incorporated by reference to Exhibit 4.3 to the Company’s Current Report on Form 8-K (File No. 001-39464) filed with the SEC on August 27, 2020).
4.3	Amendment and Assignment to Warrant Agreement, dated as of August 21, 2020, by and among Pure Acquisition Corp., Continental Stock Transfer & Trust Company and HighPeak Energy, Inc. (incorporated by reference to Exhibit 4.2 to the Company’s Registration Statement on Form S-4 and Form S-1 (File No. 333-235313) filed with the SEC on August 5, 2020).
4.4	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended (incorporated by reference to Exhibit 4.4 of the Company's Annual Report on Form 10-K for the year ended December 31, 2020 (File No. 001-39464) filed with the SEC on March 15, 2021).
4.5#	Registration Rights Agreement, dated as of June 27, 2022, by and among HighPeak Energy, Inc., Hannathon Petroleum, LLC, the parties listed as signatories thereto in their capacities as holders of Registrable Securities, and any Transferees thereof which hold Registrable Securities (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K (File No. 001-39464) filed with the SEC on June 30, 2022).
10.1	HighPeak Energy, Inc. Second Amended and Restated Long Term Incentive Plan (incorporated by reference to Exhibit 10.12 to the Company’s Annual Report on Form 10-K (File No. 001-39464) filed with the SEC on March 6, 2023).
10.2	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.4 to the Company’s Current Report on Form 8-K (File No. 001-39464) filed with the SEC on August 27, 2020).
10.3	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (File No. 001-39464) filed with the SEC on November 9, 2020).

10.4	Term Loan Credit Agreement, dated September 12, 2023, by and between HighPeak Energy, Inc., as borrower, Texas Capital Bank, as administrative agent, Chambers Energy Management, LP, as collateral agent, and the lenders from time-to-time party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on November 6, 2023).
10.5	Collateral Agency Agreement, dated September 12, 2023, by and between HighPeak Energy, Inc., Texas Capital Bank, as collateral agent, Chambers Energy Management, LP, as term representative, and Mercuria Energy Trading SA, as first out representative (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on November 6, 2023).
10.6	Credit Agreement, dated November 1, 2023, by and between HighPeak Energy, Inc., as borrower Fifth Third Bank, National Association, as administrative agent and collateral agent, and lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on November 6, 2023).
10.7	Form of Dividend Equivalent Award Agreement (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (File No. 001-39464) filed with the SEC on August 9, 2021).
10.8	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 99.2 to the Company's Registration Statement on Form S-8 (File No. 333-249888) filed with the SEC on November 5, 2020).
10.9	Form of Cash Award Agreement (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K (File No. 001-39464) filed with the SEC on March 7, 2022).
10.10	Form of Subscription Agreement, by and among HighPeak Energy, Inc. and the purchaser party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on August 24, 2022).
21.1	List of Subsidiaries.
23.1	Consent of Weaver and Tidwell, L.L.P., independent registered public accounting firm for HighPeak Energy, Inc.
23.2	Consent of Cawley, Gillespie & Associates, Inc.
31.1	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241)
31.2	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241)
32.1	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350)

32.2	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350)
97.1	High Peak Energy, Inc. Incentive-Based Compensation Recoupment Policy effective December 1, 2023.
99.1	Reserve Report of HighPeak Energy as of December 31, 2023.
99.2	Reserve Report of HighPeak Energy as of December 31, 2022 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K (File No. 001-39464) filed with the SEC on March 6, 2023).
99.3	Reserve Report of HighPeak Energy as of December 31, 2021 (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K (File No. 001-39464) filed with the SEC on February 9, 2022).
101.INS	Inline XBRL Instance Document
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HIGHPEAK ENERGY, INC.

March 6, 2024	By: /s/ Steven Tholen Steven Tholen Chief Financial Officer
March 6, 2024	By: /s/ Keith Forbes Keith Forbes Vice President, Controller

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/ JACK HIGHTOWER Jack Hightower	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	March 6, 2024
/s/ STEVEN THOLEN Steven Tholen	Chief Financial Officer (Principal Financial Officer)	March 6, 2024
/s/ KEITH FORBES Keith Forbes	Vice President, Controller (Principal Accounting Officer)	March 6, 2024
/s/ JAY M. CHERNOSKY Jay M. Chernosky	Director	March 6, 2024
/s/ KEITH A. COVINGTON Keith A. Covington	Director	March 6, 2024
/s/ JASON A. EDGEWORTH Jason A. Edgeworth	Director	March 6, 2024
/s/ SHARON FULGHAM Sharon Fulgham	Director	March 6, 2024
/s/ MICHAEL L. HOLLIS Michael L. Hollis	President and Director	March 6, 2024
/s/ LARRY C. OLDHAM Larry C. Oldham	Director	March 6, 2024