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

FORM 10-Q

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

For the quarterly period ended June 30, 2026
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** (Address of principal executive offices and zip code)	**76102** (Zip Code)

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

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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

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 is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ **No** ☒

As of August 6, 2026, there were 126,452,804 shares of common stock, par value $0.0001 per share, issued and outstanding.

HIGHPEAK ENERGY, INC.
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Definitions of Certain Terms and Conventions Used Herein

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

- "***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.
- “***First Facility Amendment***” means the First Amendment to Senior Credit Facility Agreement, dated March 29, 2024, by and among HighPeak Energy, Inc., as borrower, Fifth Third Bank, National Association, as administrative agent, the guarantors party thereto and the lenders party thereto.
- “***First Term Loan Amendment***” means the First Amendment to Term Loan Credit Agreement, dated August 1, 2025, by and among 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.
- “***Formation***” A layer of rock which has distinct characteristics that differs from nearby rocks.
- “***Fourth Facility Amendment***” means the Fourth Amendment to Senior Credit Facility Agreement, dated June 30, 2026, by and between HighPeak Energy, Inc., as borrower, Fifth Third Bank, National Association, as administrative agent, the guarantors party thereto and the lenders party thereto.
- “***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, and a wholly owned subsidiary of HighPeak Energy Partners, LP, a Delaware limited partnership.
- “***HighPeak II***” means HighPeak Energy II, LP, a Delaware limited partnership, and a wholly owned subsidiary of HighPeak Energy Partners 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.
- “***HPK 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, 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 a wholly owned subsidiary of HighPeak Energy, LP and the HPK Contributors and each of their respective affiliates and certain permitted transferees, collectively.
- “***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 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.
- *“**Second Facility Amendment**”* means the Second Amendment to Senior Credit Facility Agreement, dated August 1, 2025, by and among HighPeak Energy, Inc., as borrower, Fifth Third Bank, National Association, as administrative agent, the guarantors party thereto and the lenders party thereto.
- *“**Second Term Loan Amendment**”* means the Second Amendment to the Term Loan Credit Agreement, dated March 5, 2026, by and among 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.
- *“**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 Term Loan 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.
- *“**Third Facility Amendment**”* means the Third Amendment to Senior Credit Facility Agreement, dated March 5, 2026, by and between HighPeak Energy, Inc., as borrower, Fifth Third Bank, National Association, as administrative agent, the guarantors party thereto and the lenders party thereto.
- *“**Third Term Loan Amendment**”* means the Third Amendment to the Term Loan Credit Agreement, dated June 25, 2026, by and among HighPeak Energy, Inc., as borrower, Texas Capital Bank, as administrative agent, Chambers Energy Management, LP, as collateral agent, and certain lenders 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, which expired on August 21, 2025.
- *“**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 Quarterly Report on Form 10-Q (this "Quarterly 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 Quarterly 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 regarding the following factors:

- 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;
- the results of our ongoing strategic alternatives review process;
- inflation rates and the impacts of associated monetary policy responses, including increased or decreased interest rates and resulting pressures on economic growth, U.S. trade policy and the imposition of and changes to tariffs;
- political instability or armed conflict in crude oil or natural gas producing regions, such as the conflict in Iran, the ongoing war between Russia and Ukraine, other conflicts in the Middle East and developments in Venezuela;
- volatility in the political, legal and regulatory environments, including the effects of a prolonged U.S. government shutdown;
- political and regulatory uncertainties;
- our liquidity, cash flow and access to capital, including 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;
- the availability of capital resources;
- our ability to maintain compliance with the covenants in our debt agreements (or to seek waivers or modifications thereunder) and refinance or pay, when due, the principal of, interest or other amounts due in respect of our indebtedness;
- production and reserve levels;
- drilling and completion risks;
- 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;
- severe 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;
- 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;
- our ability to predict and manage the effects of actions of OPEC and its non-OPEC allies, known collectively as OPEC+, and agreements to set and maintain production levels;
- recent management changes;
- cyber-attacks;
- occurrence of property acquisitions or divestitures;
- the integration of acquisitions; 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" and "Part II, Item 7A. Quantitative and Qualitative Disclosures about Market Risk," included in the Company's Annual Report on Form 10-K for the year ended December 31, 2025 filed with the SEC on March 11, 2026 ("Annual Report") and this Quarterly 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. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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

	June 30, 2026 (Unaudited)	December 31, 2025
ASSETS		
Current assets:		
Cash and cash equivalents	$ 146,346	$ 162,075
Accounts receivable	83,064	55,546
Derivative instruments	27,815	29,574
Inventory	3,817	7,648
Prepaid expenses	3,217	5,054
Total current assets	264,259	259,897
Crude oil and natural gas properties, using the successful efforts method of accounting:		
Proved properties	4,663,607	4,477,368
Unproved properties	57,439	59,285
Accumulated depletion, depreciation and amortization	(1,832,511)	(1,606,217)
Total crude oil and natural gas properties, net	2,888,535	2,930,436
Other property and equipment, net	3,259	3,012
Derivative instruments	3,349	4,197
Other noncurrent assets	15,182	16,172
Total assets	$ 3,174,584	$ 3,213,714
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 120,000	$ 60,000
Accounts payable – trade	52,609	84,313
Accrued capital expenditures	45,471	30,921
Revenues and royalties payable	32,610	30,665
Derivative instruments	25,652	380
Other accrued liabilities	13,877	20,927
Derivative settlements payable	11,960	—
Advances from joint interest owners	2,867	2,205
Operating leases	448	845
Total current liabilities	305,494	230,256
Noncurrent liabilities:		
Long-term debt, net	1,068,913	1,132,807
Deferred income taxes	228,433	239,636
Asset retirement obligations	16,659	15,944
Derivative instruments	3,881	360
Operating leases	75	142
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, $0.0001 par value, 10,000,000 shares authorized, none issued and outstanding at June 30, 2026 and December 31, 2025	—	—
Common stock, $0.0001 par value, 600,000,000 shares authorized, 126,452,804 and 125,330,104 shares issued and outstanding at June 30, 2026 and December 31, 2025, respectively	13	13
Additional paid-in capital	1,163,740	1,162,007
Retained earnings	387,376	432,549
Total stockholders' equity	1,551,129	1,594,569
Total liabilities and stockholders' equity	$ 3,174,584	$ 3,213,714

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Operating revenues:				
Crude oil sales	$ 260,361	$ 196,723	$ 459,516	$ 443,147
NGL and natural gas sales	12,058	19,749	28,788	45,636
Total operating revenues	272,419	216,472	488,304	488,783
Operating costs and expenses:				
Crude oil and natural gas production	32,641	33,726	62,165	69,288
Gathering, processing and transportation	17,234	16,072	34,967	30,935
Production and ad valorem taxes	13,254	12,391	25,154	27,543
Exploration and abandonments	4,444	1,109	5,186	1,373
Depletion, depreciation and amortization	113,429	101,226	226,443	210,551
Accretion of discount	302	256	597	500
General and administrative	7,004	5,671	12,749	12,016
Stock-based compensation	868	88	1,733	265
Total operating costs and expenses	189,176	170,539	368,994	352,471
Other expense	3,000	2,489	3,050	2,489
Income from operations	80,243	43,444	116,260	133,823
Interest and other income	1,032	361	1,981	1,171
Interest expense	(35,978)	(36,412)	(71,016)	(73,400)
Gain (loss) on derivative instruments, net	53,426	26,446	(103,601)	18,519
Income (loss) before income taxes	98,723	33,839	(56,376)	80,113
Provision for income taxes	16,448	7,663	(11,203)	17,602
Net income (loss)	$ 82,275	$ 26,176	$ (45,173)	$ 62,511
Earnings per share:				
Basic net income (loss)	$ 0.60	$ 0.19	$ (0.36)	$ 0.46
Diluted net income (loss)	$ 0.59	$ 0.19	$ (0.36)	$ 0.45
Weighted average shares outstanding:				
Basic	125,286	123,930	125,276	123,922
Diluted	126,409	126,095	125,276	126,169
Dividends declared per share	$ —	$ 0.04	$ —	$ 0.08

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

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

Three and Six Months Ended June 30, 2026

	Shares Outstanding	Common Stock	Additional Paid-in-Capital	Retained Earnings	Total Stockholders' Equity
Balance, December 31, 2025	125,330	$ 13	$ 1,162,007	$ 432,549	$ 1,594,569
Stock-based compensation costs:					
Restricted shares issued to employees	1,028	—	—	—	—
Compensation costs included in net income	—	—	865	—	865
Net loss	—	—	—	(127,448)	(127,448)
Balance, March 31, 2026	126,358	13	1,162,872	305,101	1,467,986
Stock-based compensation costs:					
Restricted shares issued to outside directors	95	—	—	—	—
Compensation costs included in net income	—	—	868	—	868
Net income	—	—	—	82,275	82,275
Balance, June 30, 2026	126,453	$ 13	$ 1,163,740	$ 387,376	$ 1,551,129

Three and Six Months Ended June 30, 2025

	Shares Outstanding	Common Stock	Additional Paid-in-Capital	Retained Earnings	Total Stockholders' Equity
Balance, December 31, 2024	126,067	$ 13	$ 1,166,609	$ 435,834	$ 1,602,456
Dividends declared ($0.04 per share)	—	—	—	(5,043)	(5,043)
Dividend equivalents declared on outstanding stock options ($0.04 per share)	—	—	—	(531)	(531)
Stock-based compensation costs:					
Compensation costs included in net income	—	—	177	—	177
Net income	—	—	—	36,335	36,335
Balance, March 31, 2025	126,067	13	1,166,786	466,595	1,633,394
Dividends declared ($0.04 per share)	—	—	—	(5,042)	(5,042)
Dividend equivalents declared on outstanding stock options ($0.04 per share)	—	—	—	(531)	(531)
Exercise of warrants	—	—	1	—	1
Stock-based compensation costs:					
Restricted shares issued to outside directors	65	—	—	—	—
Compensation costs included in net income	—	—	88	—	88
Net income	—	—	—	26,176	26,176
Balance, June 30, 2025	126,132	$ 13	$ 1,166,875	$ 487,198	$ 1,654,086

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

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

	Six Months Ended June 30,	
	2026	**2025**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss) income	$ (45,173)	$ 62,511
Adjustments to reconcile net (loss) income to net cash provided by operations:		
Provision for deferred income taxes	(11,203)	17,602
Loss (gain) on derivative instruments, net	103,601	(18,519)
Cash (paid) received on settlement of derivative instruments	(72,201)	4,341
Amortization of debt issuance costs	2,238	4,091
Amortization of discounts on long-term debt	—	4,879
Stock-based compensation expense	1,733	265
Accretion expense	597	500
Depletion, depreciation and amortization expense	226,443	210,551
Exploration and abandonment expense	4,656	859
Changes in operating assets and liabilities:		
Accounts receivable	(27,519)	13,817
Prepaid expenses, inventory and other assets	5,401	4,977
Accounts payable, accrued liabilities and other current liabilities	(8,027)	(7,609)
Net cash provided by operating activities	180,546	298,265
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to crude oil and natural gas properties	(186,372)	(306,157)
Changes in working capital associated with oil and gas property additions	(818)	(12,907)
Acquisitions of crude oil and natural gas properties	(2,558)	(3,584)
Proceeds from sales of properties	18	570
Other property additions	(413)	—
Net cash used in investing activities	(190,143)	(322,078)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Debt issuance costs	(6,132)	—
Borrowings under Senior Credit Facility Agreement	—	30,000
Repayments under Term Loan Credit Agreement	—	(60,000)
Dividends paid	—	(9,922)
Dividend equivalents paid	—	(1,062)
Proceeds received from exercise of warrants	—	1
Net cash used in financing activities	(6,132)	(40,983)
Net decrease in cash and cash equivalents	(15,729)	(64,796)
Cash and cash equivalents, beginning of period	162,075	86,649
Cash and cash equivalents, end of period	$ 146,346	$ 21,853
Supplemental cash flow information:		
Cash paid for interest	$ 68,778	$ 64,430
Cash (received from) paid for income taxes	$ (242)	$ —
Supplemental disclosure of non-cash transactions:		
Additions to asset retirement obligations	$ 549	$ 1,153

The accompanying notes are an integral part of these condensed 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. See the Company's Annual Report on Form 10-K for the year ended December 31, 2025, filed with the U.S. Securities and Exchange Commission ("SEC") on March 11, 2026, for further information regarding the formation of the Company. HighPeak Energy's common stock is listed and traded on the Nasdaq Global Market (the "Nasdaq") under the ticker symbol "HPK." 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. In the opinion of management, the unaudited interim condensed consolidated financial statements of the Company as of June 30, 2026 and for the three and six months ended June 30, 2026 and 2025 include all adjustments and accruals, consisting only of normal, recurring adjustments and accruals necessary for a fair presentation of the results for the interim periods in conformity with generally accepted accounting principles in the United States ("GAAP"). Certain reclassifications have been made to prior period amounts to conform to the current period's presentation, specifically gathering, processing and transportation expenses, which were previously netted against NGL and natural gas sales and are now reflected as a component of total operating costs and expenses, which had no effect on the previously reported total assets, total liabilities, stockholders' equity, results of operations or cash flows. The operating results for the three and six months ended June 30, 2026 are not indicative of results for a full year.

Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted in accordance with the rules and regulations of the SEC. These unaudited interim condensed consolidated financial statements should be read together with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2025.

Principles of consolidation. The condensed 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.

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 June 30, 2026 and December 31, 2025, the Company's accounts receivables primarily consist of amounts due from the sale of crude oil, NGL and natural gas of $60.8 million and $35.4 million, respectively, and are based on estimates of sales volumes and realized prices the Company anticipates it will receive, a receivable from the State of Texas of $10.0 million for a multi-year natural gas severance tax refund as of both June 30, 2026 and December 31, 2025, receivables from electric power infrastructure installed throughout Flat Top by the Company for which it will be reimbursed totaling $4.1 million and $224,000, respectively, joint interest receivables of $3.3 million and $4.8 million, respectively, current U.S. federal income tax receivables of $2.9 million and $3.2 million, respectively, and receivables related to settlements of derivative contracts of $1.9 million and $1.9 million, respectively. 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.

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 June 30, 2026 and December 31, 2025, the Company had no allowance for credit losses related to accounts receivable.

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 six months ended June 30, 2026 and 2025, sales to the Company's largest purchaser accounted for approximately 88% and 87%, respectively, of the Company's total crude oil, NGL and natural gas sales revenues and sales to the Company's second largest purchaser accounted for approximately 6% and 10%, respectively, 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 June 30, 2026 and December 31, 2025 is $3.8 million and $7.6 million, respectively, and the Company has not recognized any valuation allowance to date.

Prepaid expenses. Prepaid expenses are comprised primarily of software maintenance fees that will be amortized over the life of the contracts, fees related to advisory services that will be deducted from eventual commissions on a future transaction, if any, caliche that will be used on future locations and roads in our development areas and prepaid insurance, listing, subscription and agency fees. Prepaid expenses as of June 30, 2026 and December 31, 2025 are $3.2 million and $5.1 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. 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 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 $1.5 million and $1.3 million as of June 30, 2026 and December 31, 2025, respectively, are as follows (in thousands):

	June 30, 2026	December 31, 2025
Land	$ 1,851	$ 1,869
Transportation equipment	695	411
Buildings	495	502
Leasehold improvements	170	177
Field equipment	48	52
Furniture and fixtures	—	1
Total other property and equipment, net	$ 3,259	$ 3,012

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 June 30, 2026 and December 31, 2025, the Company had aid-in-construction assets totaling $14.7 million and $15.2 million, respectively, included in other noncurrent assets. The Company funded aid-in-construction projects during the six months ended June 30, 2026 and 2025 of zero and $71,000, respectively, under the contract. 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. Payments received during the six months ended June 30, 2026 and 2025 were approximately $531,000 and $878,000, respectively. The contract calls for future additional aid-in-construction fundings 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 June 30, 2026 and December 31, 2025 totaled approximately $305.5 million and $230.3 million, respectively, including current maturities of long-term debt, trade accounts payable, accrued capital expenditures, revenues and royalties payable, derivative instruments mark-to-market liabilities, derivative settlements payable, advances from joint interest owners and accruals for operating and general and administrative expenses, operating leases and other miscellaneous items.

Debt issuance costs and original issue discount. The Company has paid and has capitalized a total of $15.1 million in debt issuance costs, $6.1 million and $7.9 million of which were incurred during the six months ended June 30, 2026 and the year ended December 31, 2025, respectively, primarily related to amendments to the Term Loan Credit Agreement and Senior Credit Facility Agreement in June 2026, March 2026 and August 2025, respectively. Amortization based on the straight-line method over the terms of the Term Loan Credit Agreement and Senior Credit Facility Agreement which approximates the effective interest method was $2.2 million and $4.1 million during the six months ended June 30, 2026 and 2025, respectively. In addition, the Company realized a total of $30.0 million in original issue discounts on the issuance of its Term Loan Credit Agreement that were being amortized over the life of the agreement which approximates the effective interest method and was zero and $4.9 million during the six months ended June 30, 2026 and 2025, respectively. All unamortized debt issuance costs and discounts as of the refinancing of the Term Loan Credit Agreement in August 2025 were charged to expense and included in loss on extinguishment of debt. See Note 7 for more information. As of June 30, 2026 and December 31, 2025, the remaining net debt issuance costs 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 June 30, 2026 and December 31, 2025, the Company had receivables related to contracts with purchasers of approximately $60.8 million and $35.4 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. 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 June 30, 2026 and December 31, 2025.

Tax benefits from 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 for the six months ended June 30, 2026 and 2025 in the accompanying consolidated financial statements.

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 or modification 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.

Reportable Segments. The Company is an independent energy company engaged in the exploration, development and production of crude oil and natural gas. The Company's crude oil and natural gas exploration and production activities are solely focused in the U.S., specifically the Midland Basin portion of the Permian Basin in West Texas. For financial reporting purposes, the Company aggregates its operations into one reporting segment due to the similar geographic location and nature of the operations.

The Company's President and Chief Executive Officer is the chief operating decision maker ("CODM"). To assess the performance of our assets, the CODM uses net income. We believe net income provides information useful in assessing our operating and financial performance across periods.

The following table reflects the Company's net income, assets and capital expenditures for the Company's one reporting segment for the time periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Total operating revenues	$ 272,419	$ 216,472	$ 488,304	$ 488,783
Lease operating expenses	26,498	29,014	53,307	60,613
Gathering, processing and transportation expense	17,234	16,072	34,967	30,935
Production and ad valorem taxes	13,254	12,391	25,154	27,543
Expensed workover costs	6,143	4,712	8,858	8,675
Total significant expenses	63,129	62,189	122,286	127,766
Depletion, depreciation and amortization	113,429	101,226	226,443	210,551
General and administrative expenses, including stock-based comp	7,872	5,759	14,482	12,281
Interest expense, net (1)	34,946	36,051	69,035	72,229
Provision for income taxes	16,448	7,663	(11,203)	17,602
Other segment items (2)	(45,680)	(22,592)	112,434	(14,157)
Total expenses	190,144	190,296	533,477	426,272
Net income (loss)	$ 82,275	$ 26,176	$ (45,173)	$ 62,511
Total assets	$ 3,174,584	$ 3,089,453	$ 3,174,584	$ 3,089,453
Capital costs incurred, including acquisitions	$ 109,930	$ 126,507	$ 188,500	$ 308,839

(1) Interest expense, net included in segment net income includes interest expense and loss on extinguishment of debt, if any, partially offset by interest income.

(2) Other segment items included in segment net income are exploration and abandonment expense, accretion of discount, other expense and gains and losses on derivative instruments.

Recently adopted accounting pronouncements. In December 2023, the FASB issued ASU 2023-09, "Income Taxes (Topic 740): Improvements to Income Tax Disclosures," which is intended to enhance the transparency and decision usefulness of income tax disclosures. The amendments in this standard provide for enhanced income tax information primarily through changes to the rate reconciliation and income taxes paid. This ASU is effective for the Company prospectively to all annual periods beginning after December 15, 2024, and interim reporting periods beginning after December 15, 2025. The Company adopted this update effective December 31, 2025. While the adoption of this ASU modified the Company's disclosures, it had no impact on the Company's consolidated balance sheets, consolidated statements of operations or consolidated statements of cash flows in its consolidated financial statements.

New accounting pronouncements not yet adopted. In November 2024, the FASB issued ASU 2024-03, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses*, which requires additional disclosure about specified categories of expenses included in relevant expense captions presented on the Condensed Consolidated Statement of Operations. The amendments are effective for annual periods beginning after December 15, 2026, and for interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. The amendments may be applied either prospectively or retrospectively. Management is currently evaluating this ASU to determine its impact on the Company's disclosures. Adoption of the update will not impact the Company's consolidated balance sheets, consolidated statements of operations or consolidated statements of cash flows in its consolidated financial statements or its liquidity.

The Company considers the applicability and the impact of all ASUs. ASUs not listed above were assessed and determined to be either not applicable, previously disclosed, or not material upon adoption.

NOTE 3. ***Acquisitions and Divestitures***

Acquisitions. During the six months ended June 30, 2026 and 2025, the Company incurred a total of $2.6 million and $3.6 million, respectively, in acquisition costs primarily to acquire various undeveloped crude oil and natural gas leases largely contiguous to its Flat Top and Signal Peak operating areas.

Divestitures. During the six months ended June 30, 2025, the Company sold various non-core non-operated working interests in certain producing properties outside of our core areas for total proceeds of $570,000.

NOTE 4. Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgement and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair value of its assets and liabilities.

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and liabilities measured at fair value on a recurring basis. Assets and liabilities measured at fair value on a recurring basis as of June 30, 2026 and December 31, 2025 are as follows (in thousands):

	As of June 30, 2026			
	(Level 1)	(Level 2)	(Level 3)	Total Gross Fair Value
Assets:				
Commodity price derivatives – current	$ —	$ 27,815	$ —	$ 27,815
Commodity price derivatives – noncurrent	—	3,349	—	3,349
Total assets	—	31,164	—	31,164
Liabilities:				
Commodity price derivatives – current	—	25,652	—	25,652
Commodity price derivatives – noncurrent	—	3,881	—	3,881
Total liabilities	—	29,533	—	29,533
Total recurring fair value measurements, net	$ —	$ 1,631	$ —	$ 1,631

	As of December 31, 2025			
	(Level 1)	(Level 2)	(Level 3)	Total Gross Fair Value
Assets:				
Commodity price derivatives – current	$ —	$ 29,574	$ —	$ 29,574
Commodity price derivatives – noncurrent	—	4,197	—	4,197
Total assets	—	33,771	—	33,771
Liabilities:				
Commodity price derivatives – current	—	380	—	380
Commodity price derivatives – noncurrent	—	360	—	360
Total liabilities	—	740	—	740
Total recurring fair value measurements, net	$ —	$ 33,031	$ —	$ 33,031

Commodity price derivatives. The Company's commodity price derivatives for crude oil are currently made up of swap contracts, costless collars, roll swaps and basis swaps and for natural gas are currently made up of swap contracts and basis swaps. 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, (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, and (iii) asset retirement obligations are measured at estimated fair value on the date the liabilities are incurred using Level 3 inputs based on expected future costs to retire the assets, market conditions and estimated lives of the assets. 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. As of June 30, 2026 and December 31, 2025, the Company has financial instruments consisting primarily of cash and cash equivalents, accounts receivable, accounts payable, long-term debt (specifically the Term Loan Credit Agreement and Senior Credit Facility 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 utilizes derivative financial instruments, primarily swaps, costless collars, basis swaps and roll swaps 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 Company has not designated its derivative financial instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Noncash derivative gain (loss), net	$ 108,154	$ 19,034	$ (31,400)	$ 14,178
Cash (payments) receipts on settled derivatives, net	(54,728)	7,412	(72,201)	4,341
Derivative gain (loss), net	$ 53,426	$ 26,446	$ (103,601)	$ 18,519

By using derivative instruments to economically hedge exposure to changes in commodity prices, the Company exposes itself to credit risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company has entered into commodity derivative instruments only with counterparties that are also lenders under its Term Loan Credit Agreement and Senior Credit Facility Agreement and have been deemed acceptable credit risk. As such, collateral is not required from either the counterparties or the Company on its outstanding derivative contracts.

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 Cushing and Argus WTI Midland crude oil prices. As such, the Company primarily uses NYMEX WTI Cushing derivative contracts as well as Argus WTI Midland basis swaps and NYMEX WTI roll swaps from time to time to manage future crude oil price volatility. The Argus WTI Midland basis differential represents the amount of premium to NYMEX WTI Cushing.

The Company's outstanding NYMEX WTI Cushing, Argus WTI Midland and NYMEX WTI Roll crude oil derivative instruments as of June 30, 2026 and the weighted average crude oil prices per barrel for those contracts are as follows:

Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Swap Price per Bbl	Costless Collar Floor Price per Bbl	Costless Collar Ceiling Price per Bbl
Crude Oil:							
Jul – Sep	2026	Costless Collar	13,000	WTI Cushing	$ —	$ 61.38	$ 69.39
Jul – Sep	2026	Swap	5,000	WTI Cushing	$ 63.45	$ —	$ —
Jul – Sep	2026	Roll Swap	26,011	NYMEX WTI Roll	$ 4.30		$ —
Jul – Sep	2026	Basis Swap	23,000	Argus WTI Midland	$ 1.37	$ —	$ —
Oct – Dec	2026	Costless Collar	10,800	WTI Cushing	$ —	$ 61.67	$ 68.52
Oct – Dec	2026	Swap	5,000	WTI Cushing	$ 63.45	$ —	$ —
Oct – Dec	2026	Roll Swap	25,000	NYMEX WTI Roll	$ 4.23	$ —	$ —
Oct – Dec	2026	Basis Swap	23,000	Argus WTI Midland	$ 1.37	$ —	$ —
Jan – Mar	2027	Costless Collar	8,900	WTI Cushing	$ —	$ 59.78	$ 65.24
Jan – Mar	2027	Swap	4,400	WTI Cushing	$ 62.14	$ —	$ —
Jan – Mar	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —
Apr – Jun	2027	Costless Collar	4,000	WTI Cushing	$ —	$ 52.00	$ 62.85
Apr – Jun	2027	Swap	6,470	WTI Cushing	$ 59.61	$ —	$ —
Apr – Jun	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —
Jul – Sep	2027	Swap	8,950	WTI Cushing	$ 61.46	$ —	$ —
Jul – Sep	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —
Oct – Dec	2027	Swap	7,500	WTI Cushing	$ 70.42	$ —	$ —
Oct – Dec	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —

Natural gas production derivatives. The Company sells its natural gas production at the tailgate of the gas processing plants and the sales contracts governing such natural gas production are correlated with HH and WAHA natural gas prices. As such, the Company primarily uses HH and WAHA derivative contracts to manage future natural gas price volatility.

The Company's outstanding HH and WAHA natural gas derivative instruments as of June 30, 2026 and the weighted average natural gas prices per MMBtu for those contracts are as follows:

Settlement Month	Settlement Year	Type of Contract	MMBtu Per Day	Index		Price per MMBtu
Natural Gas:						
Jul – Sep	2026	Swap	30,000	HH	$	4.300
Oct – Dec	2026	Swap	30,000	HH	$	4.300
Oct – Dec	2026	Basis Swap	15,000	WAHA	$	(1.667)
Jan – Mar	2027	Swap	19,667	HH	$	4.300
Jan – Mar	2027	Basis Swap	15,000	WAHA	$	(1.525)
Apr – Jun	2027	Basis Swap	15,000	WAHA	$	(1.525)
Jul – Sep	2027	Basis Swap	15,000	WAHA	$	(1.525)
Oct – Dec	2027	Basis Swap	15,000	WAHA	$	(1.525)

Balance Sheet Offsetting of Derivative Assets and Liabilities. The fair value of derivative instruments is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. While it is acceptable to record these fair values by netting asset and liability positions, including any deferred premiums, that are with the same counterparty and are subject to contractual terms which provide for net settlement, the Company elects to record them at the gross level showing assets and liabilities as if they were settled separately. See Note 4 – Fair Value Measurements for further details. Net derivative assets associated with the Company's open commodity derivative instruments by counterparty are as follows (in thousands):

		As of June 30, 2026
J. Aron & Company LLC	$	21,330
Macquarie Bank Limited		(2,295)
Mercuria Energy Trading SA		(3,977)
Fifth Third Bank, National Association		(13,427)
	$	1,631

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 condensed 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):

		Six Months Ended June 30, 2026
Beginning capitalized exploratory/extension well costs	$	16,117
Additions to exploratory/extension well costs		59,456
Reclassification to proved properties		(36,305)
Exploratory/extension well costs charged to exploration and abandonment expense		(566)
Ending capitalized exploratory/extension well costs	$	38,702

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 debt issuance costs, are as follows (in thousands):

		June 30, 2026		December 31, 2025
Term Loan Credit Agreement due 2028	$	1,200,000	$	1,200,000
Senior Credit Facility Agreement due 2028		—		—
Debt issuance costs, net (a)		(11,087)		(7,193)
Total debt		1,188,913		1,192,807
Less current maturities of long-term debt		(120,000)		(60,000)
Long-term debt, net	$	1,068,913	$	1,132,807

(a) Debt issuance costs as of June 30, 2026 and December 31, 2025 consisted of $15.1 million and $8.9 million, respectively, in costs less accumulated amortization of $4.0 million and $1.7 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") in an aggregate principal amount of $1.2 billion, 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 was set to mature on September 30, 2026. On August 1, 2025, the Company entered into the First Term Loan Amendment whereby, among other things, (i) the maturity was extended to September 30, 2028, (ii) borrowings were upsized to $1.2 billion, providing additional liquidity, and (iii) the quarterly amortization payments of $30.0 million were deferred for one year such that they begin again in September 2026. As a result of this amendment which was considered an extinguishment of debt, the Company recognized a loss on extinguishment of debt of $25.4 million consisting of (i) $11.5 million in unamortized discounts, (ii) $9.2 million in unamortized debt issuance costs and (iii) $4.7 million in premiums paid to those lenders that chose to exit the Term Loan Credit Agreement upon closing of the First Term Loan Amendment. Effective as of December 30, 2025, the Company entered into the Second Term Loan Amendment whereby, among other things, (i) the Company has been required to maintain an asset coverage ratio of not less than 1.00 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.25x decrease in the required ratio levels for such quarters, (ii) the Company has been required to maintain a total net leverage ratio of not greater than 2.50 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.50x increase in the required ratio levels for such quarters, (iii) the Company's hedging obligations has been increased requiring it to maintain hedging agreements with respect to 75% of its proved developed producing oil production for the period from April 1, 2026 to March 31, 2027 and 60% of its proved developed producing oil production for the period from April 1, 2027 to September 30, 2027, in each case as provided in the Company's reserve report as of December 31, 2025 and (iv) the Company is prohibited from making quarterly dividends on its common stock until September 30, 2026. On June 25, 2026, the Company entered into the Third Term Loan Amendment whereby, the Company will be required to maintain a total net leverage ratio of not greater than 2.25 to 1.00 for the second quarter of 2026, representing a 0.25x increase in the required ratio level for such quarter. For the third quarter of 2026 and quarterly periods ending thereafter, the required asset coverage ratio and total net leverage ratio levels will reset to the levels provided for such quarters in the Second Term Loan Amendment. As of June 30, 2026, $1.2 billion was outstanding under the Term Loan Credit Agreement. 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 a payment or other event of default exists and is continuing, at the election of the Required Lenders (as defined in 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 otherwise applicable thereto. The Company is able to repay any amounts borrowed prior to the maturity date without premium or penalty. The Term Loan Credit Agreement is guaranteed by the Company and certain of its subsidiaries and is secured by a first-lien second-out security interest in substantially all assets of the Company and certain of its subsidiaries, which will require the Company to comply with an asset coverage ratio of not less than 1.25:1.00 for the fiscal quarter ending June 30, 2026 and 1.50:1.00 for fiscal quarters ending thereafter and a total net leverage ratio of not greater than 2.00:1.00 for the fiscal quarter ending June 30, 2026 and fiscal quarters ending thereafter.

The Term Loan Credit Agreement contains customary restrictive covenants that limit the ability of the Company and its restricted subsidiaries to, among other things, incur additional indebtedness (with exceptions permitting, among other things, the incurrence of a super priority revolving credit facility, subject to a cap of $100 million), incur additional liens, make investments and loans, enter into mergers and acquisitions, make dividends and certain other payments, enter into certain hedging transactions, sell assets, engage in transactions with affiliates and make certain capital expenditures.

In addition, the Term Loan Credit Agreement contains customary mandatory prepayments, in addition to quarterly scheduled amortization payments of $30.0 million referenced above, consisting of prepayments with proceeds of prohibited indebtedness and asset sales (including hedge terminations) in excess of $20.0 million in any calendar year, and prepayments with a percentage of Excess Cash Flow (as defined in the Term Loan Credit Agreement) equal to 0%, 25% or 50% based on a total net leverage ratio to the extent pro forma for any such payment, the aggregate cash and cash equivalents of the Company and its restricted subsidiaries would not be less than $100.0 million as of the date of such payment (with no such excess cash flow prepayments made as of June 30, 2026). The Term Loan Credit Agreement is subject to customary events of default, including upon the occurrence of 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") with Texas Capital, as collateral agent, Chambers, as term representative, and Mercuria Energy Trading SA, as initial first-out representative, which was later joined by Fifth Third Bank, National Association, as successor first-out representative.

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 holders of "first-out" obligations and obligations under the Term Loan Credit Agreement) to receive, hold, administer and distribute proceeds of the collateral and to enforce the Security Documents. Under the terms of the Collateral Agency Agreement, proceeds of collateral are first distributed to holders of "first-out" obligations, including certain hedging and cash management obligations and obligations under the Senior Credit Facility Agreement but excluding certain "excess" first-out obligations, and second to holders of obligations under the Term Loan Credit Agreement.

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, together with a number of other banks and financial institutions party thereto, to establish a senior revolving credit facility ("Senior Credit Facility Agreement"). The Senior Credit Facility Agreement has aggregate maximum commitments of $100.0 million. On August 1, 2025, the Company entered into the Second Facility Amendment which, among other things, extended the maturity date to September 30, 2028, which was not considered an extinguishment of debt. Effective as of December 30, 2025, the Company entered into the Third Facility Amendment whereby, among other things, (i) the Company has been required to maintain an asset coverage ratio of not less than 1.00 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.25x decrease in the required ratio levels for such quarters, (ii) the Company has been required to maintain a total net leverage ratio of not greater than 2.50 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.50x increase in the required ratio levels for such quarters, (iii) the Company's hedging obligations has been increased requiring it to maintain hedging agreements with respect to 75% of its proved developed producing oil production for the period from April 1, 2026 to March 31, 2027 and 60% of its proved developed producing oil production for the period from April 1, 2027 to September 30, 2027, in each case as provided in the Company's reserve report as of December 31, 2025 and (iv) the Company is prohibited from making quarterly dividends on its common stock until September 30, 2026. On June 30, 2026, the Company entered into the Fourth Facility Amendment whereby, the Company has been required to maintain a total net leverage ratio of not greater than 2.25 to 1.00 for the second quarter of 2026, representing a 0.25x increase in the required ratio level for such quarter. For the third quarter of 2026 and quarterly periods ending thereafter, the required asset coverage ratio and total net leverage ratio levels will reset to the levels provided for such quarters in the Third Facility Amendment. As of June 30, 2026, the balance due under the Senior Credit Facility Agreement was zero. 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 or other event of default exists and is continuing, at the election of the Required Lenders (as defined in 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 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 first-out security interest in substantially all assets of the Company and certain of its subsidiaries.

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 remediation of 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):

	Six Months Ended June 30, 2026
Beginning asset retirement obligations	$ 15,944
Liabilities incurred from new wells	201
Liabilities settled	(83)
Accretion of discount	597
Ending asset retirement obligations	$ 16,659

As of June 30, 2026 and December 31, 2025, all asset retirement obligations are considered noncurrent and classified as such in the accompanying condensed 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 six months ended June 30, 2026 and 2025, the Company contributed $323,000 and $241,000 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 June 30, 2026 and December 31, 2025 are as follows:

	June 30, 2026	December 31, 2025
Approved and authorized shares	16,292,914	16,284,491
Shares subject to awards issued under plan	(16,256,995)	(15,134,295)
Shares available for future grant	35,919	1,150,196

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 six months ended June 30, 2026 and 2025 was zero and a negative $109,000 due to certain forfeitures, respectively, and as of June 30, 2026 there was no unrecognized stock-based compensation expense related to unvested stock option awards. 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 value of stock options granted on the grant date using a Black-Scholes option valuation model, which requires the Company to make several assumptions. In 2025, the Company approved an extension of the expiration term for certain outstanding stock options, lengthening the window to exercise those awards, and the table below reflects such extension. The expected term of the stock options granted was determined based on the simplified method of the midpoint between the vesting dates and the contractual term of the stock options. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the stock 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, 2024	13,444,062	$ 11.95	5.3	$ 53,093
Forfeitures	(739,168)	$ 24.99		
Outstanding at December 31, 2025	12,704,894	$ 11.19	4.2	$ —
Forfeitures	—	$ —		
Outstanding at June 30, 2026	12,704,894	$ 11.19	3.7	$ —
Vested at December 31, 2025	12,704,894	$ 11.19	4.2	$ —
Exercisable at December 31, 2025	10,755,894	$ 11.31	4.8	$ —
Vested at June 30, 2026	12,704,894	$ 11.19	3.7	$ —
Exercisable at June 30, 2026	10,755,894	$ 11.31	4.3	$ —

Restricted stock issued to 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 were set to vest on the three-year anniversary of such grant assuming the employees remain in his or her position as of the anniversary date. Therefore, no stock-based compensation expense was recognized during the six months ended June 30, 2026 and 2025, and there is no remaining unrecognized stock-based compensation expense as of June 30, 2026 to be recognized, which was based upon the closing price of the stock on the date of the restricted stock issuance. The Board also approved a total of 600,000 shares of restricted stock to be granted to certain employees of the Company on June 1, 2022, which were set to vest on November 4, 2024, assuming the employees remain in his or her position as of that date. Therefore, no stock-based compensation expense was recognized during the six months ended June 30, 2026 and 2025, and there is no remaining unrecognized stock-based compensation expense as of June 30, 2026 to be recognized, which was based upon the closing price of the stock on the date of the restricted stock issuance. On October 31, 2024, the vesting date for the aforementioned 2,100,500 shares of restricted stock was extended from November 4, 2024 to December 31, 2025 to ensure said restricted stock would continue to provide retention value to the Company. There is no excess stock-based compensation expense as the closing price on the modification date was lower than the original grant dates. On September 15, 2025, the Company's Chief Executive Officer retired and in conjunction with said retirement, the 1,385,500 shares of restricted stock issued to him vested immediately. As a result, 545,195 shares were withheld and cancelled in lieu of $3.8 million in cash taxes withheld and paid by the Company on his behalf. On December 31, 2025, the remaining 715,000 shares of restricted stock issued to certain other employees vested. As a result, 256,989 shares were withheld and cancelled in lieu of $1.2 million in cash taxes withheld and paid by the Company on their behalf. On January 9, 2026, a total of 1,028,000 shares of restricted stock was approved by the Board to be granted to certain employees of the Company which will vest pro-rata over the next three years assuming the employees remain in his or her position as of the annual anniversary dates or upon a change of control. Therefore, compensation expense of $1.4 million and zero was recognized during the six months ended June 30, 2026 and 2025, respectively, and there is $3.1 million in unrecognized stock-based compensation expense as of June 30, 2026 to be recognized, which was based upon the closing price of the stock on the date of the restricted stock issuance.

Restricted stock issued to outside directors. A total of 94,700 shares of restricted stock was approved by the Board to be granted to the outside directors of the Company on June 2, 2026, which will vest at the next annual meeting, assuming the Board members maintain their positions on the Board. Therefore, stock-based compensation expense of $63,000 was recognized during the six months ended June 30, 2026 and the remaining $687,000 will be recognized through May 2027, which was based upon the closing price of the stock on the date of the restricted stock issuance. Further, a total of 64,792 shares of restricted stock was approved by the Board to be granted to the outside directors of the Company on June 3, 2025, which vested on June 2, 2026. Therefore, stock-based compensation expense of $295,000 and $59,000 was recognized during the six months ended June 30, 2026 and 2025, respectively, which was based upon the closing price of the stock on the date of the restricted stock issuance. Finally, a total of 53,879 shares of restricted stock was approved by the Board to be granted to the outside directors of the Company on June 4, 2024 and which vested on June 3, 2025. Therefore, stock-based compensation expense of zero and $316,000 was recognized during the six months ended June 30, 2026 and 2025, 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 June 30, 2026 the Company had right-of-use assets totaling $499,000 included in other noncurrent assets and operating lease liabilities totaling $523,000, $448,000 of which is included in current liabilities and $75,000 of which is included in noncurrent liabilities, and as of December 31, 2025 the Company had right-of-use assets totaling $957,000 included in other noncurrent assets and operating lease liabilities totaling $987,000, $845,000 of which are included in current liabilities and $142,000 of which are included in noncurrent liabilities on the accompanying condensed 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):

	June 30, 2026
Remainder of 2026	$ 394
2027	118
2028	27
Total	539

Less present value discount	(16)
Present value of lease liabilities	$ 523

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 September 2024, the Company entered into an amended and restated 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 and Signal Peak where DKL is continually expanding their 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 May 2024 that totals $138.7 million based on the gross piped barrels delivered of 23,500 Bopd for the first ten years of the contract at a certain amount per barrel escalating throughout the term of the contract. However, the Company generally has the ability under the contract to cumulatively bank dollars based on excess volumes delivered to offset the minimum volume commitment. For the period from May 1, 2024 to June 30, 2026, the Company has delivered approximately 32,022 Bopd under the contract. The remaining monetary commitment as of June 30, 2026, if the Company never delivers any additional volumes under the agreement, is approximately $107.7 million.

Power contracts. In June 2022, the Company entered into a contract to receive a block of electric power at an attractive variable rate, which fluctuates based on the usage by the Company through May 31, 2032. In March 2024, the Company entered into a contract to receive an additional block of electric power under similar terms. In conjunction with these contracts, the Company has a $4.6 million Letter of Credit in place in lieu of a deposit that is cancellable at the end of the contract term.

NOTE 11. Related Party Transactions

Retirement of Jack Hightower. On September 16, 2025, the Company announced Mr. Jack Hightower's retirement and resignation from his role as Chief Executive Officer and Chairman of the Board of the Company, effective as of September 15, 2025 (the "Separation Date"). In connection with Mr. Hightower's notice of retirement and resignation from employment with the Company and his resignation from the Board, the Company entered into a Separation Agreement and General Release of Claims with Mr. Hightower on September 15, 2025 (the "Separation Agreement"), pursuant to which Mr. Hightower released the Company and its affiliates from certain liabilities and agrees to certain restrictive covenants. The Company, in turn, released Mr. Hightower from certain liabilities and provided Mr. Hightower with certain payments and benefits pursuant to the terms and conditions of the Separation Agreement, which, among other things, modified the benefits provided under Mr. Hightower's outstanding equity awards, namely, his outstanding stock option grant notices and agreements, dated August 24, 2020, November 4, 2021, May 4, 2022, and August 15, 2022, respectively (the "Stock Option Agreements"), and his certain restricted stock agreement and the amendment thereto, dated November 4, 2021 and October 31, 2024, respectively (the "Restricted Stock Agreement"). The Separation Agreement provided for (i) Mr. Hightower's 1,385,500 unvested shares outstanding under the Restricted Stock Agreement to fully vest as of the Separation Date; (ii) extending the period in which Mr. Hightower may exercise the stock options pursuant to the 2020 and 2021 Stock Option Agreements such that the stock options pursuant to such agreements remains exercisable by Mr. Hightower until the date that is twelve (12) months following the Separation Date; (iii) forfeiture by Mr. Hightower of the right to exercise the outstanding stock options granted pursuant to the 2022 Stock Option Agreements as of the Separation Date; (iv) a cash separation payment to Mr. Hightower in the amount of $2,400,000, payable on the Company's next regularly scheduled payroll date after the Separation Date and (v) the registration of Mr. Hightower's 1,532,478 founder's shares as soon as reasonably possible following the Separation Date.

NOTE 12. Major Customers

Delek accounted for approximately 88% and 87% and Energy Transfer Crude Marketing, LLC ("ETC") accounted for less than 10% and approximately 10% of the Company's revenues during the six months ended June 30, 2026 and 2025, respectively. Based on the current demand for crude oil and natural gas and the availability of other purchasers, management believes the loss of either 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

Income Tax Expense (Benefit)

The following table presents the Company's income tax expense (benefit) (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Current income tax expense:				
Federal	$ —	$ —	$ —	$ —
State	—	—	—	—

Total current income tax expense	—	—	—	—
Deferred income tax expense (benefit):				
Federal	15,612	7,262	(11,377)	16,834
State	836	401	174	768
Deferred income tax expense (benefit)	16,448	7,663	(11,203)	17,602
Total provision for income taxes	$ 16,448	$ 7,663	$ (11,203)	$ 17,602

The income tax (benefit) expense differed from the amounts computed by applying the U.S. federal income tax rate to (losses) earnings before income taxes as a result of the following (in thousands, except rate):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2026		2025		2026		2025	
Income tax expense (benefit) at U.S. federal statutory rate	$ 20,732	21%	$ 7,106	21%	$ (11,839)	21%	$ 16,824	21%
State income tax, net of federal income tax effect (1)	836	1	401	1	174	—	768	1
Tax Credits	—	—	—	—	—	—	—	—
Changes in valuation allowances	—	—	—	—	—	—	—	—
Nontaxable or nondeductible items:								
Limited tax benefit due to compensation	81	—	108	1	248	1	(4)	—
Annualized loss limitation	(5,433)	(5)	—	—	—	—	—	—
Other	232	—	48	—	214	—	14	—
Changes in unrecognized tax benefits	—	—	—	—	—	—	—	—
Other, net	—	—	—	—	—	—	—	—
Income tax expense (benefit)	$ 16,448	17%	$ 7,663	23%	$ (11,203)	20%	$ 17,602	22%

(1) State taxes in Texas make up 100% of the tax effect of this category.

Income taxes were (received from) paid to the following jurisdictions (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Federal	$ —	$ —	$ (230)	$ —
State	(12)	—	(12)	—
Total income taxes paid	$ (12)	$ —	$ (242)	$ —

On July 4, 2025, the "One Big Beautiful Bill" ("OBBB") was signed into law. The OBBB is a significant piece of tax legislation that includes provisions that restore 100% bonus depreciation under section 168(k) for certain property placed in service after January 19, 2025, allow for the expensing of domestic R&D expenditures beginning in 2025, and allow for the deduction of intangible drilling costs as part of the computation of the corporate alternative minimum tax beginning in 2026. The OBBB did not have a significant impact on the Company's income tax expense.

Deferred Tax Assets and Liabilities

The following table presents the tax effects of temporary differences that give rise to the Company's deferred tax assets and liabilities (in thousands):

	June 30, 2026	December 31, 2025
Deferred tax assets:		
Interest expense limitations	$ 104,548	$ 94,623
Net operating loss carryforwards	34,355	28,360
Stock-based compensation	3,383	3,322
Other	—	44
Less: Valuation allowance	—	—
Deferred tax assets	142,286	126,349
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	(370,194)	(358,853)
Unrecognized derivative gains, net	(352)	(7,132)
Other	(173)	—
Deferred tax liabilities	(370,719)	(365,985)
Net deferred tax liabilities	$ (228,433)	$ (239,636)

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 June 30, 2026 and December 31, 2025, 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 is also subject to Texas margin tax. The Company realized zero in current Texas margin tax in the accompanying consolidated financial statements for the six months ended June 30, 2026 and 2025. The Company has recognized a net deferred Texas margin tax liability of $9.9 million and $9.7 million as of June 30, 2026 and December 31, 2025, respectively, in the accompanying condensed consolidated balance sheets.

NOTE 14. (Losses) Earnings Per Share

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

The Company's basic earnings (losses) per share attributable to common stockholders is computed as (i) net income (loss) as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings (losses) per share attributable to common stockholders is computed as (i) basic earnings (losses) 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 (losses) from operations and earnings (losses) attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings (losses) per share amounts for the three and six months ended June 30, 2026 and 2025 under the two-class method (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Net income (loss) as reported	$ 82,275	$ 26,176	$ (45,173)	$ 62,511
Participating basic earnings (a)	(7,575)	(2,546)	—	(6,086)
Basic earnings (loss) attributable to common stockholders	74,700	23,630	(45,173)	56,425
Reallocation of participating earnings	61	32	—	78
Diluted net income (loss) attributable to common stockholders	$ 74,761	$ 23,662	$ (45,173)	$ 56,503
Basic weighted average shares outstanding	125,286	123,930	125,276	123,922
Dilutive warrants and unvested stock options	—	—	—	82
Dilutive unvested restricted stock	1,123	2,165	—	2,165
Diluted weighted average shares outstanding	126,409	126,095	125,276	126,169

(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. During the six months ended June 30, 2026 and 2025, the Company issued 1,028,000 and zero shares, respectively, of restricted stock to certain employees of the Company, 94,700 and 64,792 shares, respectively, of restricted stock to outside directors of the Company and zero and 60 shares of HighPeak Energy common stock, respectively, as a result of warrants being exercised. All of the Company's remaining outstanding warrants expired on August 21, 2025. Pursuant to a sales agreement with its agents entered into on May 6, 2026, the Company may sell shares of its common stock at the market price from time to time up to a maximum aggregate of $150 million. The Company has not issued any shares of its common stock under an at the market offering thus far.

Dividends and Dividend Equivalents. In the first quarter of 2026, the Board elected to discontinue the quarterly dividend. In May 2025, the Board declared a quarterly dividend of $0.04 per share of common stock outstanding which resulted in a total of $5.0 million in dividends being paid in June 2025. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $531,000 in June 2025. In addition, the Company accrued an additional combined $84,000 in dividends on the restricted stock issued to directors, management directors and certain employees that was paid upon vesting.

In February 2025, the Board declared a quarterly dividend of $0.04 per share of common stock outstanding which resulted in a total of $5.0 million in dividends being paid in March 2025. In addition, under the terms of the LTIP, the Company paid a dividend equivalent per share to all vested stock option holders of $531,000 in March 2025. In addition, the Company accrued an additional combined $86,000 in dividends on the restricted stock issued to directors, management directors and certain employees that was paid upon vesting.

Outstanding securities. As of June 30, 2026 and December 31, 2025, the Company had 126,452,804 and 125,330,104 shares of common stock outstanding, respectively.

NOTE 16. Subsequent Events

Natural gas derivative financial instruments. Subsequent to June 30, 2026, the Company entered into the following additional natural gas derivative financial instruments:

Settlement Month	Settlement Year	Type of Contract	MMBtu Per Day	Index	Price per MMBtu	
Natural Gas:						
Oct – Dec	2026	Basis Swap	10,000	WAHA	$	(1.138)
Jan – Mar	2027	Basis Swap	10,000	WAHA	$	(1.430)
Apr – Jun	2027	Basis Swap	10,000	WAHA	$	(1.430)
Jul – Sep	2027	Basis Swap	10,000	WAHA	$	(1.430)
Oct – Dec	2027	Basis Swap	10,000	WAHA	$	(1.430)

PART I. FINANCIAL INFORMATION

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and related notes. This discussion contains certain "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. These forward-looking statements involve risks and uncertainties and 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, NGL and natural gas, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties. Please read "Cautionary Statement Concerning Forward-Looking Statements." We assume no obligation to update any of these forward-looking statements, except as required by applicable law.

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 June 30, 2026, the assets consisted of two highly contiguous leasehold positions of approximately 153,627 gross (139,833 net) acres, approximately 74% of which were held by production, with an average working interest of 91%. 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 six months ended June 30, 2026, approximately 83% and 17% of sales volumes from the assets were attributable to liquids (both crude oil and NGL) and natural gas, respectively. As of June 30, 2026, HighPeak Energy was developing its properties using one (1) drilling rig and one (1) frac crew and expects to average one (1) drilling rig and less than one (1) frac crew during the remainder of 2026 under our current development plan, depending on certain market conditions.

Transactions and Recent Developments

Debt amendments and actions taken to bolster covenant compliance. In August 2025, the Company entered into the First Term Loan Amendment and the Second Facility Amendment which amended the Term Loan Credit Agreement and the Senior Credit Facility Agreement whereby, among other things, (i) the maturity date was extended two years to September 2028, (ii) the Term Loan Credit Agreement was upsized to $1.2 billion, providing additional liquidity, and (iii) the Term Loan Credit Agreement quarterly amortization payments of $30.0 million were deferred for one year such that they begin again in September 2026.

Effective as of December 30, 2025, in order to ensure continued compliance with the financial covenants under the Term Loan Credit Agreement and the Senior Credit Facility Agreement, the Company entered into the Second Term Loan Amendment and the Third Facility Amendment whereby, among other things (i) the Company has been required to maintain an asset coverage ratio of not less than 1.00 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.25x decrease in the required ratio levels for such quarters, (ii) the Company has been required to maintain a total net leverage ratio of not greater than 2.50 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.50x increase in the required ratio levels for such quarters, (iii) the Company's hedging obligations has been increased requiring it to maintain hedging agreements with respect to 75% of its proved developed producing oil production for the period from April 1, 2026 to March 31, 2027 and 60% of its proved developed producing oil production for the period from April 1, 2027 to September 30, 2027, in each case as provided in the Company's reserve report as of December 31, 2025 and (iv) the Company is prohibited from making quarterly dividends on its common stock until September 30, 2026.

In June 2026, in order to ensure continued compliance with the financial covenants under the Term Loan Credit Agreement and the Senior Credit Facility Agreement, the Company entered into the Third Term Loan Amendment and the Fourth Facility Amendment whereby, the Company will be required to maintain a total net leverage ratio of not greater than 2.25 to 1.00 for the second quarter of 2026, representing a 0.25x increase in the required ratio level for such quarter. For the third quarter of 2026 and quarterly periods ending thereafter, the required asset coverage ratio and total net leverage ratio levels will reset to the levels provided for such quarters in the Second Term Loan Amendment and the Third Facility Amendment. It is uncertain whether the Company will be able to comply with these covenants, in particular beginning in the third quarter of 2026 when the required asset coverage ratio and total net leverage ratio levels will reset to the prior more stringent levels. The Company has already taken steps to improve these ratios, including, but not limited to, suspending the payment of dividends and reducing capital expenditures, and in connection with any potential or anticipated covenant shortfalls, the Company may seek to take other action such as raising additional capital through debt or equity offerings, selling assets, reducing capital expenditures further, obtaining additional amendments or waivers from its lenders, or pursuing other strategic alternatives. There can be no assurance that any such measures will be available on acceptable terms, or at all, or that they will be sufficient to address any covenant compliance issues. Any failure of the Company to comply with its financial covenants would result in an event of default under the Term Loan Credit Agreement and Senior Credit Facility Agreement, entitling the lenders to accelerate amounts outstanding thereunder.

Commodity Prices. Prices for crude oil, NGL and natural gas are determined primarily by market conditions. Geopolitical global conflicts, tariffs or other trade barriers and any resulting trade tensions, regional and worldwide economic activity, changes in trade or other government policies or regulations, including with respect to U.S. energy and monetary policies, extreme weather conditions and other substantially variable factors influence market conditions for these products. For example, in the last quarter, the conflict in Iran caused the global crude oil market to shift from a supply-demand surplus to a deficit, materially decreasing crude oil and refined products available to the markets, and significantly increasing benchmark crude oil prices. These factors are beyond our control and are difficult to predict. OPEC and its non-OPEC allies, known collectively as OPEC+, continue to meet regularly to evaluate the state of global crude oil supply, demand and inventory levels and can heavily influence volatility in crude oil prices. During the three months ended June 30, 2026 and 2025, weighted average WTI prices averaged $93.29 and $63.75 per Bbl, respectively, and weighted average Henry Hub prices averaged $2.90 and $3.44 per MMBtu, respectively.

Acquisitions. During the six months ended June 30, 2026, the Company incurred a total of $2.6 million in acquisition costs related to lease extensions and to acquire additional crude oil and natural gas leases covering additional contiguous bolt-on undeveloped acreage to its Flat Top and Signal Peak operating areas.

Outlook

In response to the growing global crude oil supply constraints and the improved commodity pricing environment that began in March of 2026 that we consider temporary, the Company is maintaining flexibility in its capital plan as indicated by its plan to maintain a one (1) drilling rig program for 2026 depending on certain market conditions. The Company will continue to evaluate drilling and completion activity on an economic basis, with future activity levels assessed monthly. If the Company is unable to maintain compliance with its financial covenants or obtain further amendments or waivers from its lenders, it may be required to reduce its capital expenditures, which could adversely impact its ability to develop its acreage, maintain its leasehold positions and grow its production. 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. Evercore Group L.L.C. has been retained as a financial advisor with respect to this ongoing strategic alternatives process. 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 three months ended June 30, 2026 included the highlights described below and comparative discussion of related drivers for the three months ended June 30, 2025:

- Net income was $82.3 million ($0.59 per diluted share) for the three months ended June 30, 2026 compared with net income of $26.2 million ($0.19 per diluted share) for the three months ended June 30, 2025. The primary components of the $56.1 million increase in net income include:

    - a $55.9 million increase in crude oil, NGL and natural gas revenues due to a 35% increase in average realized commodity prices per Boe, excluding the effects of derivatives partially offset by a 7% decrease in daily sales volumes resulting primarily from a decrease in crude oil sales as a result of decreased development activity and natural decline;

    - a $27.0 million increase in the Company’s derivative instruments gain as a result of its crude oil and natural gas commodity contracts entered into and the change in crude oil and natural gas prices thereafter; and

    - a $1.1 million decrease in the Company’s crude oil and natural gas production costs primarily as a result of decreased communication expenses and lower chemical and treating costs related to third party midstream expansions and debottlenecking;

partially offset by:

- a $12.2 million increase in DD&A expense primarily due to a 20% increase in the DD&A rate from $22.87 to $27.52 per Boe as a result of a decrease in proved reserves at the end of 2025 partially offset by a 7% decrease in daily sales volumes resulting primarily from a decrease in crude oil sales as a result of decreased development activity and natural decline;

- A $8.8 million increase in the Company’s income tax expense primarily due to an increase in income before income taxes;

- a $3.3 million increase in the Company’s exploration and abandonment expenses primarily due to increased abandoned leasehold costs and plugging and abandonment expenses;

- a $1.3 million increase in the Company’s general and administrative expenses primarily attributable to cash compensation to our board of directors which was implemented at the annual meeting in June 2026 and increased legal and audit expenditures due to the growth of the Company;

- a $1.2 million increase in gathering, processing and transportation expenses related to the Company’s natural gas production as a result of connecting more natural gas to processing facilities that were not previously connected, thereby enhancing the Company’s ability to maximize returns from its wells by increasing sales volumes; and

- a $863,000 increase in the Company’s production and ad valorem tax expense primarily due to the aforementioned increase in operating revenues.

- During the three months ended June 30, 2026, average daily sales volumes totaled 45,285 Boepd, compared with 48,649 Boepd during the same period in 2025, a decrease of 7%, primarily due to lower crude oil volumes as a result of decreased development activity and natural decline.

- Weighted average realized crude oil prices per Bbl, excluding the effects of derivatives, increased during the three months ended June 30, 2026 to $98.82, compared with $63.74 for the same period in 2025. Weighted average NGL prices per Bbl increased during the three months ended June 30, 2026 to $24.14, compared with $20.34 for the same period in 2025. Weighted average natural gas prices per Mcf decreased to negative $1.50 during the three months ended June 30, 2026, compared with positive $1.50 during the same period in 2025.

- Cash provided by operating activities totaled $126.3 million for the three months ended June 30, 2026, compared with $141.2 million for the three months ended June 30, 2025.

Derivative Financial Instruments

Crude oil derivative financial instrument exposure. As of June 30, 2026 and factoring in derivative instruments entered into subsequent to quarter end, the Company was party to the following open crude oil derivative financial instruments.

Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Swap Price per Bbl	Costless Collar Floor Price per Bbl	Costless Collar Ceiling Price per Bbl
Crude Oil:							
Jul – Sep	2026	Costless Collar	13,000	WTI Cushing	$ —	$ 61.38	$ 69.39
Jul – Sep	2026	Swap	5,000	WTI Cushing	$ 63.45	$ —	$ —
Jul – Sep	2026	Roll Swap	26,011	NYMEX WTI Roll	$ 4.30		$ —
Jul – Sep	2026	Basis Swap	23,000	Argus WTI Midland	$ 1.37	$ —	$ —
Oct – Dec	2026	Costless Collar	10,800	WTI Cushing	$ —	$ 61.67	$ 68.52
Oct – Dec	2026	Swap	5,000	WTI Cushing	$ 63.45	$ —	$ —
Oct – Dec	2026	Roll Swap	25,000	NYMEX WTI Roll	$ 4.23	$ —	$ —
Oct – Dec	2026	Basis Swap	23,000	Argus WTI Midland	$ 1.37	$ —	$ —
Jan – Mar	2027	Costless Collar	8,900	WTI Cushing	$ —	$ 59.78	$ 65.24
Jan – Mar	2027	Swap	4,400	WTI Cushing	$ 62.14	$ —	$ —
Jan – Mar	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —
Apr – Jun	2027	Costless Collar	4,000	WTI Cushing	$ —	$ 52.00	$ 62.85
Apr – Jun	2027	Swap	6,470	WTI Cushing	$ 59.61	$ —	$ —
Apr – Jun	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —
Jul – Sep	2027	Swap	8,950	WTI Cushing	$ 61.46	$ —	$ —
Jul – Sep	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —
Oct – Dec	2027	Swap	7,500	WTI Cushing	$ 70.42	$ —	$ —
Oct – Dec	2027	Basis Swap	10,000	Argus WTI Midland	$ 1.00	$ —	$ —

Natural gas derivative financial instrument exposure. As of June 30, 2026 and factoring in derivative financial instruments entered into subsequent to quarter end, the Company was party to the following open natural gas derivative financial instruments.

Settlement Month	Settlement Year	Type of Contract	MMBtu Per Day	Index	Price per MMBtu
Natural Gas:					
Jul – Sep	2026	Swap	30,000	HH	$ 4.300
Oct – Dec	2026	Swap	30,000	HH	$ 4.300
Oct – Dec	2026	Basis Swap	25,000	WAHA	$ (1.455)
Jan – Mar	2027	Swap	19,667	HH	$ 4.300
Jan – Mar	2027	Basis Swap	25,000	WAHA	$ (1.487)
Apr – Jun	2027	Basis Swap	25,000	WAHA	$ (1.487)
Jul – Sep	2027	Basis Swap	25,000	WAHA	$ (1.487)
Oct – Dec	2027	Basis Swap	25,000	WAHA	$ (1.487)

The estimated fair value of the outstanding open derivative financial instruments as of June 30, 2026 was a net asset of $1.6 million which is included in current assets and current and noncurrent liabilities on the Company’s condensed consolidated balance sheet as of June 30, 2026. During the six months ended June 30, 2026, the Company recognized a net derivative loss of $103.6 million, including a $31.4 million mark-to-market loss and $72.2 million in net monthly settlement payments.

Operations and Drilling Highlights

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

	Six Months Ended June 30, 2026
Crude Oil (Bbls)	29,884
NGL (Bbls)	7,919
Natural Gas (Mcf)	45,921
Total (Boe)	45,456

The Company’s liquids production was 83% of total production on a Boe basis for the six months ended June 30, 2026.

Costs incurred are as follows (in thousands):

	Six Months Ended June 30, 2026
Unproved property acquisition costs	$ 2,558
Proved acquisition costs	—
Total acquisitions	2,558
Development costs	126,484
Exploration costs	59,458
Total finding and development costs	188,500
Asset retirement obligations	549
Total costs incurred	$ 189,049

The following table sets forth the total number of horizontal producing wells drilled and completed during the six months ended June 30, 2026:

	Drilled		Completed	
	Gross	Net	Gross	Net
Flat Top area	10	9.6	13	12.6
Signal Peak area	7	7.0	7	7.0
Total	17	16.6	20	19.6

As of June 30, 2026, HighPeak Energy was developing its properties using one (1) drilling rig and one (1) frac crew. The continued conflict in Iran, commodity-specific tariffs and the possibility of trade wars, the ongoing war between Russia and Ukraine and other conflicts in the Middle East and the production cuts and reversals thereof announced by OPEC+ are continuing to evolve and in ways that are difficult or impossible to anticipate. Given the dynamic nature of this situation, the Company is maintaining flexibility with its capital plan and will continue to evaluate drilling and completion activity on an economic basis, with future activity levels assessed regularly.

During the six months ended June 30, 2026, the Company successfully completed and placed on production twenty (20) gross (19.6 net) horizontal wells. As of June 30, 2026, the Company had sixteen (16) gross (15.6 net) horizontal wells that had been drilled and were in various stages of completion. In addition, as of June 30, 2026, the Company was in the process of drilling five (5) gross (4.8 net) horizontal wells.

Results of Operations

Three and Six Months Ended June 30, 2026

Crude Oil, NGL and natural gas revenues.

Average daily sales volumes are as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Crude Oil (Bbls)	28,952	33,913	(15)%	29,884	36,056	(17)%
NGL (Bbls)	8,429	7,462	13%	7,919	7,592	4%
Natural Gas (Mcf)	47,423	43,642	9%	45,921	43,371	6%
Total (Boe)	45,285	48,649	(7)%	45,456	50,876	(11)%

The decrease in average daily Boe sales volumes for the three and six months ended June 30, 2026, compared with the same periods in 2025 was primarily due to lower crude oil sales volumes as a result of reduced development activity and natural decline partially offset by increased NGL and natural gas sales volumes due to third-party midstream expansions and debottlenecking.

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 realized prices, excluding the effects of derivatives, are as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Crude Oil per Bbl	$ 98.82	$ 63.74	55%	$ 84.95	$ 67.90	25%
NGL per Bbl	$ 24.14	$ 20.34	19%	$ 20.92	$ 22.30	(6)%
Natural Gas per Mcf	$ (1.50)	$ 1.50	(200)%	$ (0.14)	$ 1.91	(107)%
Total per Boe	$ 66.11	$ 48.90	35%	$ 59.35	$ 53.08	12%

Revenue Variance Analysis.

The following table illustrates the variance in revenues attributable to prices versus volumes (in thousands except prices and percentages):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Total operating revenues	$ 272,419	$ 216,472	26%	$ 488,304	$ 488,783	0%
Average daily sales volumes (Boe)	45,285	48,649	(7)%	45,456	50,876	(11)%
Realized price per Boe	$ 66.11	$ 48.90	35%	$ 59.35	$ 53.08	12%
Revenue change from prior period due to prices	$ 76,190		35%	$ 57,738		12%
Revenue change from prior period due to volumes	(20,238)		(9)%	(58,224)		(12)%
Rounding	(5)		0%	7		0%
Total change from prior period revenues	$ 55,497			$ (479)		

As detailed above, the increase in total operating revenues for the three months ended June 30, 2026 compared to the same period in 2025 is the result of a 35% increase in average realized price per Boe partially offset by a 7% decrease in average daily sales volumes primarily as a result of lower crude oil sales volumes as a result of reduced development activity and natural decline. Also detailed above, the decrease in total operating revenues for the six months ended June 30, 2026 compared to the same period in 2025 is the result of a 11% decrease in average daily sales volumes primarily as a result of lower crude oil sales volumes as a result of reduced development activity and natural decline partially offset by a 12% increase in average realized price per Boe.

Crude Oil and natural gas production costs.

Crude oil and natural gas production costs in total and per Boe are as follows (in thousands, except percentages and per Boe amounts):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	**2025**	**% Change**	**2026**	**2025**	**% Change**
Crude oil and natural gas production costs	$ 32,641	$ 33,726	(3)%	$ 62,165	$ 69,288	(10)%
Crude oil and natural gas production costs per Boe (excluding expense workovers)	$ 6.43	$ 6.55	(2)%	$ 6.48	$ 6.58	(2)%
Workover expense	$ 1.49	$ 1.06	41%	$ 1.08	$ 0.94	15%

The decrease in crude oil and natural gas production costs for the three and six months ended June 30, 2026 compared to the same periods in 2025 can be attributed primarily to decreased chemical and treating costs related to third party midstream expansions and debottlenecking and communication expenses.

Gathering, processing and transportation expenses.

Gathering, processing and transportation expenses are as follows (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	**2025**	**% Change**	**2026**	**2025**	**% Change**
Gathering, processing and transportation expenses	$ 17,234	$ 16,072	7%	$ 34,967	$ 30,935	13%

Gathering, processing and transportation expenses per Boe are as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	**2025**	**% Change**	**2026**	**2025**	**% Change**
Gathering, processing and transportation expenses	$ 4.18	$ 3.63	15%	$ 4.25	$ 3.36	26%

Gathering, processing and transportation expenses for the three and six months ended June 30, 2026 increased compared to the same periods in 2025. This is primarily related to connecting more natural gas to processing facilities that were not previously connected, thereby enhancing the Company's ability to maximize returns from its wells by increasing sales volumes. The slightly higher increase in the per Boe amounts can be attributed to the increase in NGL and natural gas as a total component of our product mix when calculating Boe.

Production and ad valorem taxes.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	**2025**	**% Change**	**2026**	**2025**	**% Change**
Production and ad valorem taxes	$ 13,254	$ 12,391	7%	$ 25,154	$ 27,543	(9)%

In general, production taxes and ad valorem taxes are directly related to commodity sales volumes and price changes; however, Texas ad valorem taxes are based upon an asset valuation assessed by the state as of January 1 of that particular year based on prior year commodity prices, whereas production taxes are based upon current year sales revenues at current commodity prices. Overall, the increase in production and ad valorem taxes during the three months ended June 30, 2026 compared to the same period in 2025 can be attributed primarily to the aforementioned 26% increase in operating revenues partially offset by lower ad valorem taxes and the decrease in production and ad valorem taxes during the six months ended June 30, 2026 compared to the same period in 2025 can be primarily attributed to lower ad valorem taxes.

Production and ad valorem taxes per Boe are as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	**2025**	**% Change**	**2026**	**2025**	**% Change**
Production taxes per Boe	$ 3.06	$ 2.32	32%	$ 2.77	$ 2.52	10%
Ad valorem taxes per Boe	$ 0.16	$ 0.48	(67)%	$ 0.29	$ 0.47	(38)%

The increase in production taxes per Boe for the three and six months ended June 30, 2026, compared with the same periods in 2025 can be attributed primarily to the increased commodity prices and the lower sales volumes thus far in 2026. The change in ad valorem taxes per Boe for the three and six months ended June 30, 2026, compared with the same periods in 2025, was primarily due to the expected decrease in ad valorem taxes expected for 2026.

Exploration and abandonments expense.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Abandoned leasehold costs	$ 3,702	$ 266	1,292%	$ 3,739	$ 266	1,306%
Unsuccessful exploratory well costs	484	—	100%	566	—	100%
Geologic and geophysical personnel costs	245	253	(3)%	530	513	3%
Plugging and abandonment expenses	13	590	(98)%	349	594	(41)%
Geologic and geophysical data costs	—	—	n/m	2	—	100%
Exploration and abandonments expense	$ 4,444	$ 1,109	301%	$ 5,186	$ 1,373	278%

Exploration and abandonment costs increased during the three and six months ended June 30, 2026 primarily due to increased abandoned leasehold costs related primarily to outlying leases that the Company was not successful extending at attractive prices and unsuccessful well costs related to initial costs on a well that the Company elected not to drill partially offset by lower plugging and abandonment expenses.

DD&A expense.

DD&A expense and DD&A expense per Boe are as follows (in thousands, except percentages and per Boe amounts):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
DD&A expense	$ 113,429	$ 101,226	12%	$ 226,443	$ 210,551	8%
DD&A expense per Boe	$ 27.52	$ 22.87	20%	$ 27.52	$ 22.86	20%

The increase in DD&A during the three and six months ended June 30, 2026 is primarily due to an increase in the DD&A rate primarily attributable to decreased proved reserves partially offset by decreased sales volumes.

General and administrative expense.

General and administrative expense and general and administrative expense per Boe as well as stock-based compensation expense are as follows (in thousands, except percentages and per Boe amounts):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
General and administrative expense	$ 7,004	$ 5,671	24%	$ 12,749	$ 12,016	6%
General and administrative expense per Boe	$ 1.70	$ 1.28	33%	$ 1.55	$ 1.30	19%
Stock-based compensation expense	$ 868	$ 88	886%	$ 1,733	$ 265	554%

The increase in general and administrative expense in total for the three and six months ended June 30, 2026 compared to the same periods in 2025 is primarily a result of higher cash compensation to independent members of our Board of Directors and increased legal and audit expenses partially offset by decreased wages and benefits primarily related to the retirement of the Company's former chief executive officer in September 2025. The increase in stock-based compensation expense for the three and six months ended June 30, 2026 compared to the same periods in 2025 is the result of restricted stock issued to certain employees of the Company in January 2026.

Interest expense.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Term Loan Credit Agreement	$ 34,427	$ 31,715	9%	$ 68,393	$ 64,058	7%
Senior Credit Facility Agreement	197	187	5%	385	372	3%
Amortization of debt issuance costs	1,354	2,057	(34)%	2,238	4,091	(45)%
Amortization of discount	—	2,453	(100)%	—	4,879	(100)%
	$ 35,978	$ 36,412	(1)%	$ 71,016	$ 73,400	(3)%

The decrease in interest expense can be attributed to a decrease in amortization of discounts and debt issuance costs related to the refinancing of the Company's debt in August 2025 partially offset by an increased outstanding debt balance in 2026 compared to 2025.

Loss on derivative instruments, net.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Noncash gain (loss) on derivative instruments, net	$ 108,154	$ 19,034	468%	$ (31,400)	$ 14,178	(321)%
Cash (payments) receipts on settlement derivatives, net	(54,728)	7,412	(838)%	(72,201)	4,341	(1,763)%
Gain (loss) on derivative instruments, net	$ 53,426	$ 26,446	102%	$ (103,601)	$ 18,519	(659)%

The Company primarily utilizes commodity swap contracts, costless collars, roll swaps and basis swaps to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (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 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 derivative swap contracts, costless collars, roll swaps and basis swaps and natural gas derivative swap contracts and basis swaps.

Other expense.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Financial advisor fee	$ 3,000	$ —	100%	$ 3,000	$ —	100%
Debt refinancing costs	—	2,489	(100)%	—	2,489	(100)%
Other	—	—	—	50	—	100%
	$ 3,000	$ 2,489	21%	$ 3,050	$ 2,489	23%

During the three and six months ended June 30, 2026, the Company expensed the financial advisory fee paid to Texas Capital Securities related to its ongoing strategic alternatives process as the agreement was terminated. During the three and six months ended June 30, 2025, the Company incurred approximately $2.5 million in rating agency fees, legal and accounting professional fees and other costs related to a proposed refinancing of its existing debt obligations. The Company ultimately elected to not close that specific refinancing transaction. Accordingly, these costs were expensed as incurred.

Provision for income taxes.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	% Change	2026	2025	% Change
Provision for income taxes	$ 16,448	$ 7,663	115%	$ (11,203)	$ 17,602	(164)%
Effective income tax rate	16.7%	22.6%	(26)%	19.9%	22.0%	(10)%

The change in provision for income taxes during the three and six months ended June 30, 2026, compared with the same periods in 2025, was primarily due to the change in income (loss) before income taxes mainly due to the significant increase in derivative gains and losses as well as the reversal of an annualized loss limitation during the three months ended June 30, 2026 that was recognized during the three months ended March 31, 2026 which was reversed primarily due to the large increase in commodity prices that resulted in an increase in income before income taxes. The effective income tax rate differs from the statutory rate primarily due to Texas state margin taxes and other permanent differences between GAAP income and taxable income. See Note 13 of Notes to Condensed Consolidated Financial Statements included in "Item 1. Condensed Consolidated Financial Statements (Unaudited)" for additional information.

Liquidity and Capital Resources

Liquidity. The Company's primary sources of short-term liquidity are (i) cash and cash equivalents, (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) 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 other contractual obligations, (iv) working capital obligations, and (v) interest payments on and amortizations 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 2026 planned capital expenditures and provide adequate liquidity to fund other needs, however this may be subject to significant uncertainty due to changes in crude oil, NGL and natural gas pricing and potential covenant compliance issues under its debt instruments described below and no assurance can be given that such funding sources will be adequate to meet the Company's future needs.

As of June 30, 2026, the Company was in compliance with the financial covenants under its Term Loan Credit Agreement and Senior Credit Facility Agreement, as amended. In particular, we recently entered into credit facility amendments described below to ensure our continued compliance with covenants in our debt instruments, but it is uncertain whether the Company will be able to comply with these covenants, in particular beginning in the third quarter of 2026 when the required asset coverage ratio and total net leverage ratio levels will reset to the prior more stringent levels. The Company has already taken steps to improve these ratios, including, but not limited to, suspending the payment of dividends and reducing capital expenditures, and in connection with any potential or anticipated covenant shortfalls, the Company may seek to take other action such as raising additional capital through debt or equity offerings, selling assets, reducing capital expenditures further, obtaining additional amendments or waivers from its lenders, or pursuing other strategic alternatives. There can be no assurance that any such measures will be available on acceptable terms, or at all, or that they will be sufficient to address any covenant compliance issues. If the Company is unable to maintain compliance with its financial covenants or successfully implement the measures described above, its liquidity and capital resources would be materially and adversely affected. Specifically, the Company's borrowing availability under its Senior Credit Facility Agreement, which was approximately $92.1 million as of June 30, 2026, could be reduced or eliminated, and the Company may be unable to access additional debt or equity financing on acceptable terms or at all**.** In addition, any failure of the Company to comply with its financial covenants would result in an event of default under the Term Loan Credit Agreement and Senior Credit Facility Agreement, entitling the lenders to accelerate amounts outstanding thereunder. If such amounts were accelerated and became immediately due and payable, the Company does not expect it would have sufficient liquidity to repay such indebtedness and would likely need to pursue a restructuring, refinancing or other strategic alternatives, which may not be available on acceptable terms or at all.

Debt Refinancing and Recent Amendments. 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 was set to mature on September 30, 2026 prior to the amendments discussed below. 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 contained 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 prior to the amendments discussed below. 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 contained 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 and effective March 29, 2024 pursuant to the First Facility Amendment, current commitments of $100.0 million and customary debt issuance costs which totaled approximately $1.1 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.

August 2025 Amendments

In August 2025, the Company entered into the First Term Loan Amendment and the Second Facility Amendment which amended the Term Loan Credit Agreement and the Senior Credit Facility Agreement whereby, among other things, (i) the maturity date was extended two years to September 2028, (ii) the Term Loan Credit Agreement was upsized to $1.2 billion, providing additional liquidity, and (iii) the Term Loan Credit Agreement quarterly amortization payments of $30.0 million were deferred for one year such that they begin again in September 2026.

February 2026 Amendments

Effective as of December 30, 2025, in order to ensure continued compliance with the financial covenants under the Term Loan Credit Agreement and the Senior Credit Facility Agreement, the Company entered into the Second Term Loan Amendment and the Third Facility Amendment whereby, among other things, (i) the Company has been required to maintain an asset coverage ratio of not less than 1.00 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.25x decrease in the required ratio levels for such quarters, (ii) the Company has been required to maintain a total net leverage ratio of not greater than 2.50 to 1.00 for the fourth quarter of 2025 and the first quarter of 2026, representing a 0.50x increase in the required ratio levels for such quarters, (iii) the Company's hedging obligations has been increased requiring it to maintain hedging agreements with respect to 75% of its proved developed producing oil production for the period from April 1, 2026 to March 31, 2027 and 60% of its proved developed producing oil production for the period from April 1, 2027 to September 30, 2027, in each case as provided in the Company's reserve report as of December 31, 2025 and (iv) the Company is prohibited from making quarterly dividends on its common stock until September 30, 2026.

June 2026 Amendments

In June 2026, in order to ensure continued compliance with the financial covenants under the Term Loan Credit Agreement and the Senior Credit Facility Agreement, the Company entered into the Third Term Loan Amendment and the Fourth Facility Amendment whereby, the Company will be required to maintain a total net leverage ratio of not greater than 2.25 to 1.00 for the second quarter of 2026, representing a 0.25x increase in the required ratio level for such quarter. For the third quarter of 2026 and quarterly periods ending thereafter, the required asset coverage ratio and total net leverage ratio levels will reset to the levels in effect for such quarters prior to these amendments.

Common Stock Issuance. Pursuant to a sales agreement with its agents entered into on May 6, 2026, the Company may sell shares of its common stock at the market price from time to time up to a maximum aggregate of $150 million. The Company has not issued any shares of its common stock under an at the market offering thus far.

Unless otherwise specified in any prospectus supplement, the Company intends to use the net proceeds from the sale of its securities offered under these prospectuses for working capital and general corporate purposes including, but not limited to, capital expenditures, repayment of indebtedness, potential acquisitions and other business opportunities. Pending any specific application, the Company may initially invest funds in short-term marketable securities or apply them to the reduction of indebtedness.

***2026 capital budget*.** The Company's capital budget for 2026 is expected to be in the range of approximately $255 to $285 million for operated and non-operated drilling, completion, facilities and equipping crude oil wells, field infrastructure buildout and other costs, excluding acquisitions. The 2026 capital budget excludes acquisitions, asset retirement obligations, geological and geophysical expenses and general and administrative expenses. HighPeak Energy expects to fund its forecasted capital expenditures with cash on its consolidated balance sheet, cash generated by operations and borrowing capacity available under its Senior Credit Facility Agreement, if needed. The Company's capital expenditures for the year ended December 31, 2025 were $511.8 million, including the completion and/or continuation of certain one-time infrastructure projects but excluding acquisitions.

However, there are many factors and consequences beyond the Company's control impacting our capital budget, such as political and regulatory uncertainties, economic downturn or potential recession, geo-political risks and additional actions by businesses, OPEC or OPEC+, and governments in response to pandemics, that may have an impact on the Company's future results and drilling plans. For additional information on the risks, see "Part II, Item 1A. Risk Factors" of this Quarterly Report. 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. Cash flows from operating, investing and financing activities are summarized below (in thousands).

	Six Months Ended June 30,			
	2026	**2025**	**Change**	**% Change**
Net cash provided by operating activities	$ 180,546	$ 298,265	$ (117,719)	(39)%
Net cash used in investing activities	$ (190,143)	$ (322,078)	$ 131,935	(41)%
Net cash (used in) provided by financing activities	$ (6,132)	$ (40,983)	$ 34,851	(85)%

Operating activities. The decrease in net cash flow provided by operating activities for the six months ended June 30, 2026, compared with the same period in 2025, was primarily related to a decrease in discretionary cash flow as a result of a decrease in derivative settlements of approximately $76.5 million associated with higher overall commodity prices and an increased amount of derivative transactions entered into by the Company in accordance with its Term Loan Credit Agreement and Senior Credit Facility Agreement coupled with an overall increase in accounts receivable changes of $41.3 million related to increased commodity prices.

Investing activities. The decrease in net cash used in investing activities for the six months ended June 30, 2026, compared with 2025, was primarily due to decreases in additions to crude oil and natural gas properties.

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

- Six months ended June 30, 2026: The Company paid debt issuance costs of $6.1 million primarily related to the Second Term Loan Amendment and the Third Facility Amendment.

- Six months ended June 30, 2025: The Company made a mandatory amortization payment on its Term Loan Credit Agreement totaling $60.0 million and paid dividends and dividend equivalents of $9.9 million and $1.1 million, respectively, partially offset by borrowings under our Senior Credit Facility Agreement of $30.0 million.

Interest Rate Risk. We are exposed to market risk due to the floating interest rates associated with any outstanding balance on the Term Loan Credit Agreement and the Senior Credit Facility Agreement. As of June 30, 2026, 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 of the Term Loan Credit Agreement at the end of each quarter 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 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 but are significantly down from the past two years. Additionally, commodity prices are subject to heightened levels of uncertainty related to geopolitical issues such as the ongoing war between Russia and Ukraine, conflicts in the Middle East, and U.S. intervention in Venezuela. The realized prices we receive for our production also depend on numerous factors that are typically beyond our control. Based on our sales volumes during the six months ended June 30, 2026 and excluding the effects on derivatives, a $1.00 per barrel increase (decrease) in the weighted average crude oil price for the six months ended June 30, 2026 would have increased (decreased) the Company's revenues by approximately $11.5 million on an annualized basis and a $0.10 per Mcf increase (decrease) in the weighted average natural gas price for the six months ended June 30, 2026 would have increased (decreased) the Company's revenues by approximately $1.7 million on an annualized basis.

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 June 30, 2026, a $1.00 increase (decrease) in the forward curves associated with our crude oil commodity derivative instruments would have decreased (increased) our net derivative positions for these products by approximately $6.8 million. Additionally, as of June 30, 2026, a $0.10 increase (decrease) in the forward curves associated with our natural gas commodity derivative instruments would have decreased (increased) our net derivative positions for these products by approximately $729,000.

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, loss on extinguishment of debt, 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 Condensed Consolidated Financial Statements included in “Item 1. Condensed Consolidated Financial Statements (Unaudited)” of this Quarterly 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):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Net income	$ 82,275	$ 26,176	$ (45,173)	$ 62,511
Interest expense	35,978	36,412	71,016	73,400
Interest and other income	(1,032)	(361)	(1,981)	(1,171)
Provision for income taxes	16,448	7,663	(11,203)	17,602
Depletion, depreciation and amortization	113,429	101,226	226,443	210,551
Accretion of discount	302	256	597	500
Exploration and abandonment expense	4,444	1,109	5,186	1,373
Stock based compensation	868	88	1,733	265
Derivative related noncash activity	(108,154)	(19,034)	31,400	(14,178)
Other expense	3,000	2,489	3,050	2,489
EBITDAX	$ 147,558	$ 156,024	$ 281,068	$ 353,342

New Accounting Pronouncements

Our historical condensed consolidated financial statements and related notes to condensed consolidated financial statements contain information that is pertinent to our management’s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done, and judgments made on how the specifics of a given rule apply to us.

In management’s opinion, the more significant reporting areas impacted by management’s judgments and estimates are the choice of accounting method for crude oil and natural gas activities, crude oil, NGL and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations, accounting and valuation of nonmonetary transactions, litigation and environmental contingencies, valuation of financial derivative instruments, uncertain tax positions and income taxes.

Management’s judgments and estimates in all the areas listed above are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the three months ended June 30, 2026. See our disclosure of critical accounting policies in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8. Financial Statements and Supplementary Data” of our Annual Report.

New accounting pronouncements issued but not yet adopted. The effects of new accounting pronouncements are discussed in Note 2 of Notes to Condensed Consolidated Financial Statements included in "Item 1. Condensed Consolidated Financial Statements (Unaudited)."

ITEM 3. 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, 2021 through June 30, 2026, the calendar month average NYMEX WTI crude oil price per Bbl ranged from a low of $52.10 to a high of $114.34, and the last trading day NYMEX natural gas price per MMBtu ranged from a low of $1.58 to a high of $9.35. A $1.00 per barrel increase (decrease) in the weighted average crude oil price for the six months ended June 30, 2026 would have increased (decreased) the Company's revenues by approximately $11.5 million on an annualized basis, excluding the effects of derivatives, and a $0.10 per Mcf increase (decrease) in the weighted average natural gas price for the six months ended June 30, 2026 would have increased (decreased) the Company's revenues by approximately $1.7 million on an annualized basis, excluding the effects of derivatives.

Due to this volatility, the Company uses commodity derivative instruments, such as swaps, collars, roll 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 June 30, 2026 market quotes were as follows:

	Remainder of 2026	Year Ending December 31, 2027
Average forward NYMEX crude oil price per Bbl	$ 68.70	$ 66.42
Average forward NYMEX natural gas price per MMBtu	$ 3.38	$ 3.46

The average forward prices based on August 6, 2026 market quotes were as follows:

	Remainder of 2026	Year Ending December 31, 2027
Average forward NYMEX crude oil price per Bbl	$ 73.95	$ 69.15
Average forward NYMEX natural gas price per MMBtu	$ 2.95	$ 3.29

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 June 30, 2026, we had $1.2 billion outstanding under the Term Loan Credit Agreement and had $92.1 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 June 30, 2026 would have resulted in an annual increase in interest expense of approximately $12.0 million.

ITEM 4. 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 period covered by this Quarterly Report. Based on that evaluation, HighPeak Energy’s principal executive officer and principal financial officer concluded that the Company’s disclosure controls and procedures were effective, as of the end of the period covered by this Quarterly Report, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, including that such information is accumulated and communicated to the Company’s management, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in 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 June 30, 2026 that have materially affected or are reasonably likely to materially affect the Company’s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, the Company may be a party to various lawsuits, proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of 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 results of operations.

ITEM 1A. RISK FACTORS

In addition to the information set forth in this Quarterly Report, the risks that are discussed in the Company’s Annual Report under the headings “Risk Factors,” “Business and Properties,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk,” should be carefully considered, as such risks could materially affect the Company's business, financial condition or future results. There has been no material change in the Company's risk factors that were described in the Company’s Annual Report.

ITEM 5. OTHER INFORMATION

During the three months ended June 30, 2026, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Second Amended & 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	Second 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 May 1, 2026).
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).
10.1	Fourth Amendment to Revolving Credit Agreement, dated as of June 30, 2026, by and between HighPeak Energy, Inc., as borrower, Fifth Third Bank, National Association, as administrative agent, the guarantors party thereto and the 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 June 30, 2026).
10.2	Third Amendment to Credit Agreement, dated June 25, 2026, by and among HighPeak Energy, Inc., as borrower, the guarantors party thereto, Texas Capital Bank, as administrative agent, Chambers Energy Management, LP, as collateral agent, and certain lenders party thereto (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 June 30, 2026).
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).
101.INS**	Inline XBRL Instance Document – The instance document does not appear in the Interactive Data File because its XBRL tabs are embedded within the Inline XBRL 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).

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* Filed herewith.
** Furnished herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned hereto duly authorized.

		HIGHPEAK ENERGY, INC.
August 10, 2026	By:	/s/ Steven Tholen Steven Tholen Chief Financial Officer
August 10, 2026	By:	/s/ Keith Forbes Keith Forbes Vice President and Chief Accounting Officer

EXHIBIT 31.1

CHIEF EXECUTIVE OFFICER CERTIFICATION

I, Michael Hollis, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of HighPeak Energy, Inc.;

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

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

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

/s/ Michael Hollis

Michael Hollis
President and Chief Executive Officer
Date: August 10, 2026

EXHIBIT 31.2

CHIEF FINANCIAL OFFICER CERTIFICATION

I, Steven Tholen, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of HighPeak Energy, Inc.;

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

/s/ Steven Tholen

Steven Tholen
Chief Financial Officer
Date: August 10, 2026

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF HIGHPEAK ENERGY, INC.
PURSUANT TO 18 U.S.C. § 1350

I, Michael Hollis, President and Chief Executive Officer of HighPeak Energy, Inc. (the "Company"), hereby certify, in the capacity and on the date indicated below, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge, the accompanying Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2026:

1. Fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael Hollis
Michael Hollis
President and Chief Executive Officer
Date: August 10, 2026

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF HIGHPEAK ENERGY, INC.
PURSUANT TO 18 U.S.C. § 1350

I, Steven Tholen, Executive Vice President and Chief Financial Officer of HighPeak Energy, Inc. (the "Company"), hereby certify, in the capacity and on the date indicated below, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge, the accompanying Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2026:

1. Fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven Tholen
Steven Tholen
Chief Financial Officer
Date: August 10, 2026