UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended June 30, 2025

☐ 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 001-32942

EVOLUTION PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	**41-1781991** (IRS Employer Identification No.)

1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079
(Address of principal executive offices and zip code)

(713) 935-0122
(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	EPM	NYSE American

Securities registered pursuant to Section 12(g) of the Act: **None**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes: ☐ No: ☒

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes: ☒ No: ☐

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

Large accelerated filer	☐	Accelerated filer	☐	Non-accelerated filer	☒	Smaller reporting company	☒
						Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2024, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $5.23 on the NYSE American was $160.1 million.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 12, 2025, was 34,359,146.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2025 Annual Meeting of Stockholders to be filed within 120 days of the end of the fiscal year covered by this report are incorporated by reference into Part III of this report.

EVOLUTION PETROLEUM CORPORATION
2025 ANNUAL REPORT ON FORM 10-K

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We use the terms, "EPM," "Company," "we," "us," and "our" to refer to Evolution Petroleum Corporation, and unless the context otherwise requires, its wholly-owned subsidiaries.

FORWARD-LOOKING STATEMENTS

This Form 10-K and the information referenced herein contains forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, except for statements of historical fact, are forward-looking statements. The words "plan," "expect," "project," "estimate," "may," "assume," "believe," "anticipate," "intend," "budget," "forecast," "predict" and other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words or phrases. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors, which may include, but are not limited to, the following:

- our expectations of plans, strategies and objectives, including anticipated development activity and capital spending;
- our capital allocation strategy, capital structure, anticipated sources of funding, growth in long-term shareholder value and ability to preserve balance sheet strength;
- our ability to complete future acquisitions and the need for additional capital to complete future acquisitions;
- the benefits of our multi-basin portfolio, including operational and commodity flexibility;
- our ability to maximize cash flow and the application of excess cash flows to pay dividends;
- estimates of our oil, natural gas and NGLs production and commodity mix;
- anticipated oil, natural gas and NGL prices;
- anticipated drilling and completions activity;
- drilling and operational risks, including accidents, equipment failures, fires, and releases of toxic or hazardous materials;
- estimates of our oil, natural gas and NGL reserves and recoverable quantities;
- our ability to access credit facilities and the availability of other sources of liquidity to meet financial obligations throughout commodity price cycles;
- limitations on our ability to obtain funding based on environmental, social, and corporate governance ("ESG") performance;
- future interest expense;
- our ability to manage debt and financial ratios, finance growth and comply with financial covenants;
- the implementation and outcomes of risk management programs, including exposure to commodity price and interest rate fluctuations, the volume of oil and natural gas production hedged, and the markets or physical sales locations hedged;
- the possible impact of changes in federal, state, provincial and local, rules and regulations;
- anticipated compliance with current or proposed environmental requirements, including the costs thereof;
- the impact of greenhouse gas ("GHG") emissions limitations and renewable energy incentives;
- adequacy of provisions for abandonment and site reclamation costs;
- our operational and financial flexibility, discipline and ability to respond to evolving market conditions;
- the declaration and payment of future dividends and any anticipated repurchase of our outstanding common shares;
- the adequacy of our provision for taxes and legal claims;
- our ability to manage cost inflation and expected cost structures, including expected operating, transportation, processing and labor expenses;
- our competitiveness relative to our peers, including with respect to capital, materials, people, assets and production;
- oil, natural gas and NGL inventories and global demand for oil, natural gas and NGLs;
- the outlook of the oil and natural gas industry generally, including impacts from changes to the geopolitical environment;
- adverse weather events;
- anticipated staffing levels;
- anticipated payments related to our commitments, obligations and contingencies, and the ability to satisfy the same; and

- the possible impact of accounting and tax pronouncements, rule changes and standards.

Readers are cautioned against unduly relying on forward-looking statements which, by their nature, involve numerous assumptions and are subject to both known and unknown risks and uncertainties (many of which are beyond our control) that may cause actual events or results to differ materially and/or adversely from those expressed or implied, which include, but are not limited to, the following assumptions:

- future commodity prices and basis differentials;
- our ability to access credit facilities and shelf prospectuses;
- assumptions contained in our corporate guidance;
- the availability of attractive commodity or financial hedges and the enforceability of risk management programs;
- expectations that counterparties will fulfill their obligations pursuant to gathering, processing, transportation and marketing agreements;
- access to adequate gathering, transportation, processing and storage facilities;
- assumed tax, royalty and regulatory regimes;
- expectations and projections made in light of, and generally consistent with, our historical experience and our perception of historical industry trends; and
- the other assumptions contained herein.

Readers are cautioned that the assumptions, risks and uncertainties referenced above, and in the other documents incorporated herein by reference (if any), are not exhaustive. Although we believe the expectations represented by our forward-looking statements are reasonable based on the information available to us as of the date such statements are made, forward-looking statements are only predictions and statements of our current beliefs and there can be no assurance that such expectations will prove to be correct.

When considering any forward-looking statement, the reader should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil, natural gas and NGLs, operating risks and other risk factors as described in Part I, Item 1A. *Risk Factors* and elsewhere in this report and as also may be described from time to time in future reports we file with the Securities and Exchange Commission ("SEC"). Readers should also consider such information in conjunction with our consolidated financial statements and related notes and Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* in this report. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not currently perceive them to be material. Such factors could cause results to differ materially from our expectations.

Forward-looking statements speak only as of the date they are made, and we do not undertake to update these statements other than as required by law. Readers are advised, however, to review any further disclosures we make on related subjects in our filings with the SEC.

GLOSSARY OF SELECTED PETROLEUM INDUSTRY TERMS

Term	Definition
Bbl	One stock tank barrel, of 42 U.S. gallons of liquid volume, used herein in reference to oil or NGL.
BCF	Billion cubic feet.
BFPD	Barrels of fluid per day.
BOE	Barrels of oil equivalent. BOE is calculated by converting six MCF of natural gas and 42 gallons of NGL to one Bbl of oil which reflects energy equivalence and not price equivalence. Natural gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.
BOEPD	Barrels of oil equivalent per day.
BOPD	Barrels of oil per day.
BTU	British Thermal Unit: the standard unit of measure of energy equal to the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.
CO_2	Carbon Dioxide.
Developed Reserves	Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by a means not involving a well.
EOR	Enhanced Oil Recovery; projects that involve injection of heat, miscible or immiscible gas, or chemicals into oil reservoirs, typically following full primary and secondary waterflood recovery efforts, in order to gain incremental recovery of oil from the reservoir.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped within or related to the same geologic structural features and/or stratigraphic features.*
Farmout	Sale or transfer of all or part of the operating rights from the working interest owner (the assignor or farmout party), to an assignee (the farm-in party) who assumes all or some of the burden of development, in return for an interest in the property. The assignor may retain an overriding royalty or any other type of interest. For Federal tax purposes, a farmout may be structured as a sale or lease, depending on the specific rights and carved out interests retained by the assignor.
Gross Acres or Gross Wells	The total acres or number of wells participated in, regardless of the amount of working interest owned.
Horizontal Drilling	Involves drilling horizontally out from a vertical well-bore, thereby potentially increasing the area and reach of the well-bore that is in contact with the reservoir.
Hydraulic Fracturing	Involves pumping a fluid with or without particulates into a formation at high pressure, thereby creating fractures in the rock and leaving the particulates in the fractures to ensure that the fractures remain open which potentially increases the ability of the reservoir to produce oil or natural gas.
LOE	Lease Operating Expense(s); a current period expense incurred to operate a well.
MBBL	One thousand barrels.
MMBBL	One million barrels.
MBOE	One thousand barrels of oil equivalent.
MBOEPD	One thousand barrels of oil equivalent per day.
MMBOE	One million barrels of oil equivalent.
MCF	One thousand cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature.
MMCF	One million cubic feet of natural gas at standard conditions.
MMBTU	One million British Thermal Units.
Mineral Royalty Interest	A royalty interest that is retained by the owner of the minerals underlying a lease. See “Royalty Interest.”
Net Acres or Net Wells	The sum of the fractional working interests owned in gross acres or gross wells.

NGL	Natural Gas Liquids; the combination of ethane, propane, butane and natural gasoline that can be removed from natural gas through processing, typically through refrigeration plants that utilize low temperatures, or through plants that utilize compression, temperature reduction and expansion to a lower pressure.
Non-operated Interest	An interest in an oil and/or natural gas property but does not participate in or have any responsibility for actual operation of the property.
Non-operated Working Interest	An interest in an oil and/or natural gas property but does not participate in or have any responsibility for actual operation of the property, but is burdened with the cost of development and operation of the property.
NYMEX	New York Mercantile Exchange.
OOIP	Original Oil in Place; an estimate of the barrels originally contained in a reservoir before any production therefrom.
Operator	An oil and natural gas joint venture participant that manages the joint venture, pays venture costs and bills the venture's non-operators for their share of venture costs. The operator is also responsible to market all oil and natural gas production, except for those non-operators who take their production in-kind.
Overriding Royalty Interest or ORRI	A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of. See "Royalty Interest."
Permeability	The measure of ease with which a fluid can move through a reservoir. The unit of measure is a darcy (d), or any metric derivation thereof, such as a millidarcy (md), where one darcy equals 1,000 millidarcy. Extremely low permeability of 10 millidarcy, or less, are often associated with source rocks, such as shale. Extraction of hydrocarbons from a source rock is more difficult than a sandstone reservoir where permeability typically ranges one to two darcy or more.
Porosity	The relative volume of the pore space (or open area) compared to the total bulk volume of the reservoir, stated in percent. Higher porosity rocks provide more storage space for hydrocarbon accumulations than lower porosity rocks in a given cubic volume of reservoir.
Primary Recovery Method	The extraction of oil and natural gas from reservoirs using natural or initial reservoir pressure combined with artificial lift techniques such as pumps.
Producing Reserves	Any category of reserves that have been developed and production has been initiated.*
Producing Well	Any well that has been developed and production has been initiated.*
Proved Developed Reserves	Proved Reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by a means not involving a well.
Proved Developed Nonproducing Reserves	Proved Reserves that have been developed and no material amount of capital expenditures are required to bring on production, but production has not yet been initiated due to timing, markets, or lack of third party completed connection to a natural gas sales pipeline.*
Proved Developed Producing Reserves ("PDP")	Proved Reserves that have been developed and production has been initiated.*
Proved Reserves	Estimated quantities of oil, natural gas, and NGLs which geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic, 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.*

Proved Undeveloped Reserves ("PUD")	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 recompletion.* (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.
Present Value	When used with respect to oil and natural gas reserves, present value means the estimated future net revenues computed by applying current prices of oil and natural gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and natural gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs to be incurred in developing and producing the proved reserves) computed using a discount factor and assuming continuation of existing economic conditions.
Productive Well	A well that is producing oil or natural gas or that is capable of production.
PV-10	Means the present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes. Unless otherwise noted, PV-10 is calculated using the pricing scheme as required by the SEC. PV-10 of proved reserves is calculated the same as the standardized measure of discounted future net cash flows, except that the standardized measure of discounted future net cash flows includes future estimated income taxes discounted at 10% per annum. See the definition of standardized measure of discounted future net cash flows.
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Royalty or Royalty Interest	The mineral owner's share of oil or natural gas production (typically between 1/8 and ¼), free of costs, but subject to severance taxes unless the lessor is a government. In certain circumstances, the royalty owner bears a proportionate share of the costs of making the natural gas saleable, such as processing, compression, and gathering.
Secondary Recovery Method	The extraction of oil and natural gas from reservoirs utilizing water injection (waterflooding) in order to maintain or increase reservoir pressure and direct the displacement of oil into producing wells.
Shut-in Well	A well that is not on production, but has not been plugged and abandoned. Wells may be shut-in in anticipation of future utility as a producing well, plugging and abandonment or other use.
Standardized Measure	The standardized measure of discounted future net cash flows. The Standardized Measure is an estimate of future net cash flows associated with proved reserves, discounted at 10% per annum. Future net cash flows are calculated by reducing future net revenues by estimated future income tax expenses and discounting at 10% per annum. The Standardized Measure and the PV-10 of proved reserves are calculated in the same exact fashion, except that the Standardized Measure includes future estimated income taxes discounted at 10% per annum. The Standardized Measure is in accordance with accounting standards generally accepted in the United States of America ("GAAP").
Tertiary Recovery Method	The extraction of oil and natural gas from reservoirs which employs injection of gas, heat, or chemicals into the reservoir in order to change the physical properties of the oil and aid in its extraction, also known as Enhanced Oil Recovery (EOR).
Undeveloped Reserves	Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.*

Water Injection Well	A well which is used to inject water under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.
Working Interest	The interest in the oil and natural gas in place which is burdened with the cost of development and operation of the property. Also called the operating interest.
Workover	A remedial operation on a completed well to restore, maintain, or improve the well's production.

* This definition may be an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X.

PART I

Item 1. Business

Note: *See Glossary of Selected Petroleum Industry Terms starting on page iv.*

General

Evolution Petroleum Corporation (“Evolution,” and together with its consolidated subsidiaries, the “Company”, “our”, “we, “us” or similar terms) is an independent energy company focused on maximizing total returns to its shareholders through the ownership of and investment in onshore oil and natural gas properties in the United States. Our long-term goal is to maximize total shareholder return from a diversified portfolio of long-life oil and natural gas properties built through acquisition and through selective development opportunities, production enhancement, and other exploitation efforts on our oil and natural gas properties.

Recent Developments

Dividend Declaration

On September 11, 2025, Evolution’s Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2025.

Purchase of SCOOP/STACK Minerals

On August 4, 2025, we completed the acquisition of certain mineral and royalty interests in the SCOOP/STACK area of Oklahoma from a non-affiliated private seller (the “Minerals Acquisition”) in a cash transaction valued at approximately $17.0 million, subject to customary post-closing adjustments. The Minerals Acquisition has an effective date of May 1, 2025. We funded the purchase price for the Minerals Acquisition with a combination of $15.0 million in borrowings under our Senior Secured Credit Facility and cash on hand. The acquired assets include an average royalty interest of 0.6% located on approximately 5,500 net royalty acres located primarily in Grady and Canadian Counties, Oklahoma.

Senior Secured Credit Facility

On June 30, 2025, we entered into a syndicated amended and restated senior secured reserve-based credit agreement (the “Senior Secured Credit Facility”) with MidFirst Bank, as administrative agent for the lenders party thereto, in an amount up to $200.0 million with an initial borrowing base of $65.0 million maturing on June 30, 2028.

For further discussion of our Senior Secured Credit Facility, see “Liquidity and Capital Resources” within Item 7. *Management’s Discussion and Analysis of Financial Conditions and Results of Operations*.

Purchase of Non-operated Oil and Natural Gas Assets

On April 14, 2025, we closed the acquisition of non-operating working interests in certain long-life oil and natural gas wells located primarily in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas (the “TexMex Acquisition”) from a private seller. The total purchase price for the TexMex Acquisition was approximately $9.0 million before customary post-closing adjustments, with an effective date of February 1, 2025. We funded the purchase price for the TexMex Acquisition with a combination of cash on hand and borrowings under our Senior Secured Credit Facility.

The TexMex Acquisition includes an average working interest of 42% and an average revenue interest of 35% in approximately 600 wells.

At-the-Market (“ATM”) Equity Sales Program

On October 21, 2024, we entered into an ATM equity Sales Agreement (the “ATM Sales Agreement”) with Roth Capital

Partners, LLC (the “Lead Agent”), Northland Securities Inc., and A.G.P./Alliance Global Partners pursuant to which we may issue and sell, from time to time, up to $30.0 million of shares of common stock through or to the Lead Agent, acting as agent or principal. For the year ended June 30, 2025, we sold a total of approximately 0.7 million shares of our common stock under the ATM Sales Agreement for net proceeds of approximately $3.5 million, after deducting $0.3 million in offering costs. We intend to use the net proceeds from any sales of common stock for general corporate purposes, including to repay outstanding indebtedness.

Business Strategy

Our business strategy is to maximize total shareholder return based on our assessment of the operating environment and marketplace, subject to our obligations to other stakeholders. The key elements of our strategy to accomplish our goal of maximizing shareholder return are:

- Maintaining a strong balance sheet and conservative financial management;
- Growing the asset base through investment in our existing properties, direct acquisitions of new low decline, long-life oil and natural gas properties, selective development opportunities, or accretive acquisitions of similar companies; and
- Returning cash to shareholders by sustaining and growing our dividend payout over time or repurchases of our shares in the open market.

Properties

Our oil and natural gas properties consist primarily of non-operated interests in the following areas (as well as small overriding royalty interests in four onshore central Texas wells):

TexMex – Texas and New Mexico

Our non-operated interest in TexMex consists of oil and natural gas producing properties where we hold an approximate 42% net working interest and a 35% average net revenue interest located on approximately 27,800 gross (11,200 net) acres held by production located primarily in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas. The oil and natural gas properties are operated by Texian Operating Company.

Average net daily production from the date of acquisition through June 30, 2025 was 0.4 MBOEPD. For the year ended June 30, 2025, our average net daily production from the TexMex properties consisted of 59% oil and 41% natural gas. Hydrocarbons produced from our TexMex properties are sold to various purchasers throughout Texas, New Mexico and Louisiana.

SCOOP/STACK – Central Oklahoma

Our non-operated interests in the SCOOP and STACK plays, consist of oil and natural gas producing properties in the Anadarko basin, where we hold approximately 2.6% average net working interest and approximately 2.0% average net revenue interests located on approximately 103,700 gross (4,200 net) acres (approximately 97% held by production) across Blaine, Canadian, Carter, Custer, Dewey, Garvin, Grady, Kingfisher, McClain, Murray, and Stephens counties in Oklahoma. The oil and natural gas properties are operated by Continental Resources, Inc., Ovintiv USA Inc. and EOG Resources, Inc. with approximately 40% of wells operated by other operators.

For the year ended June 30, 2025, our average net daily production from the SCOOP/STACK properties was 1.2 MBOEPD consisting of 50% natural gas, 34% oil, and 16% NGLs. Hydrocarbons produced from our SCOOP/STACK properties are sold to various purchasers throughout the mid-continent.

Chaveroo Field – Chaves and Roosevelt Counties, New Mexico

Our non-operated interests in the Chaveroo Field consist of a 50% net working interest, with an average associated 41% revenue interest, in approximately 4,500 gross (2,300 net) acres all held by production, associated with six development blocks with the right to acquire the same working interest in additional development locations and associated acreage at a fixed price. The field is operated by PEDEVCO Corp. (“PEDEVCO”).

For the year ended June 30, 2025 our average net daily production from the Chaveroo Field properties was 0.2 MBOEPD consisting of 100% oil. Oil produced from our Chaveroo Field properties is sold to Phillips 66 in New Mexico and natural gas and NGLs are sold to Targa Resources Corp.

Jonah Field – Sublette County, Wyoming

Our non-operated interests in the Jonah Field, a natural gas and NGL property in Sublette County, Wyoming, consist of approximately 20% average net working interest and approximately 15% average net revenue interest located on approximately 5,300 gross (950 net) acres all held by production. The properties are operated by Jonah Energy ("Jonah").

For the year ended June 30, 2025 our average net daily production from the Jonah Field properties was 1.6 MBOEPD consisting of 89% natural gas, 6% NGLs, and 5% oil. Hydrocarbons produced from our Jonah Field properties are sold to West Coast markets.

Williston Basin – Williston, North Dakota

Our non-operated interests in the Williston Basin, oil and natural gas producing properties, consist of approximately 39% average net working interest and approximately 33% average net revenue interest located on approximately 138,200 gross (41,300 net) acres (approximately 97% held by production) across Billings, Golden Valley, and McKenzie Counties in North Dakota. The properties are operated by Foundation Energy Management ("Foundation").

For the year ended June 30, 2025, our average net daily production from the Willison Basin properties was 0.5 MBOEPD consisting of 76% oil, 14% NGLs, and 10% natural gas. The primary producing reservoirs are the Three Forks, Pronghorn, and Bakken formations. Hydrocarbons produced from the Williston Basin properties are sold to local refineries and purchasers.

Barnett Shale – North Texas

Our non-operated interests in the Barnett Shale, a natural gas and NGL producing shale reservoir, consist of approximately 17% average net working interest and approximately 14% average net revenue interest (inclusive of small overriding royalty interests) located on approximately 123,800 gross (21,000 net) acres held by production across nine North Texas counties (Bosque, Denton, Erath, Hill, Hood, Johnson, Parker, Somervell, and Tarrant), in the Barnett Shale. The oil and natural gas properties are primarily operated by Diversified Energy Company with approximately 10% of wells operated by six other operators.

For the year ended June 30, 2025, our average net daily production from the Barnett Shale properties was 2.4 MBOEPD consisting of 74% natural gas, 25% NGLs, and 1% oil. The producing reservoir is the Barnett Shale, which is also the source rock. Hydrocarbons produced from our Barnett Shale properties are sold to Gulf Coast markets.

Hamilton Dome – Hot Springs County, Wyoming

Our non-operated interests in the Hamilton Dome Field, a secondary recovery field utilizing water injection wells to pressurize the reservoir, consist of approximately 24% average net working interest, with an associated 20% average net revenue interest (inclusive of a small overriding royalty interest). The approximately 5,900 gross acre unitized field, of which we hold approximately 1,400 net acres, is operated by Merit Energy Company ("Merit"), a private oil and natural gas company, who owns the majority of the remaining working interest in the Hamilton Dome Field. The Hamilton Dome Field is located in the southwest region of the Big Horn Basin in northwest Wyoming.

For the year ended June 30, 2025, our average net daily production from the Hamilton Dome Field properties was 0.4 MBOEPD consisting of 100% oil. The primary producing reservoirs in the field are the Tensleep and Phosphoria. Produced oil from the field is subject to Western Canadian Select pricing.

Delhi Field – Enhanced Oil Recovery CO_2 Flood – Onshore Louisiana

Our non-operated interests in the Delhi Field, a CO_2-EOR project, consist of approximately 24% average net working interest, with an associated 19% revenue interest and separate overriding royalty and mineral interests of approximately 7% yielding a total average net revenue interest of approximately 26%. The field is operated by Denbury Onshore LLC ("Denbury"), a subsidiary of Exxon Mobil Corporation ("ExxonMobil"). The approximately 13,600 gross unitized Delhi Field, of which we hold approximately 3,200 net acres, is located in northeast Louisiana in Franklin, Madison, and Richland Parishes.

For the year ended June 30, 2025, our average net daily production from the Delhi Field properties was 0.8 MBOEPD consisting of 77% oil and 23% NGLs. The primary producing reservoirs in the field are the Tuscaloosa and Paluxy formations. Produced oil from the field is priced off of Louisiana Light Sweet ("LLS") crude, which often trades at a premium to West Texas Intermediate ("WTI").

Refer to "*Production volumes, average sales price and average production costs*" table below for further information regarding our properties and their fiscal year results.

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

The SEC sets rules related to reserve estimation and disclosure requirements for oil and natural gas companies. These rules require disclosure of oil and natural gas proved reserves by significant geographic area, using the trailing 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Subject to limited exceptions, the rules also require that proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

There are numerous uncertainties inherent in estimating quantities of proved reserves and estimates of reserves quantities and values must be viewed as being subject to significant change as more data about the properties becomes available.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2025

Our proved reserves as of June 30, 2025, denominated in thousands of barrels of oil equivalent ("MBOE"), were estimated by our independent reservoir engineers, Cawley, Gillespie and Associates, Inc. ("CG&A") and DeGolyer and MacNaughton ("D&M"), both worldwide petroleum consultants.

CG&A evaluated the reserves for our TexMex, SCOOP/STACK, Chaveroo Field, Jonah Field, and Williston Basin properties. The scope and results of their procedures are summarized in a letter from the firm, which is included as Exhibit 99.1 to this Annual Report on Form 10-K.

D&M evaluated the reserves for our Barnett Shale, Hamilton Dome, and Delhi Field properties. The scope and results of their procedures are summarized in a letter from the firm, which is included as Exhibit 99.2 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved reserves as of June 30, 2025. For additional reserves information, see our *Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data*. The New York Mercantile Exchange ("NYMEX") previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $71.20 per barrel of oil and $2.87 per MMBtu of natural gas. The net price per barrel of NGLs was $25.24, which does not have any single comparable reference index price. The NGL price was based on historical prices received. For periods for which no historical price information was available, we used comparable pricing in the geographic area. Pricing differentials were applied for each individual property and product based on quality, processing, transportation, location and other pricing aspects.

Proved Reserves as of June 30, 2025

Reserve Category	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total Proved Reserves (MBOE)[1]	Percent of Total Proved Reserves
Proved:					
Developed Producing	8,349	57,149	4,311	22,185	81.8 %
Developed Non-Producing	378	757	5	509	1.9 %
Undeveloped	3,401	3,599	412	4,413	16.3 %
Total Proved	12,128	61,505	4,728	27,107	100.0 %
Product Mix	44.8%	37.8%	17.4%	100.0%	
Total Proved by Property:					
TexMex	1,925	6,429	—	2,997	11.1 %
SCOOP/STACK	1,268	11,498	716	3,900	14.4 %
Chaveroo Field	2,889	841	179	3,208	11.8 %
Jonah Field	167	16,915	228	3,214	11.9 %
Williston Basin	1,841	1,120	275	2,303	8.5 %
Barnett Shale	74	24,702	1,903	6,094	22.5 %
Hamilton Dome Field	1,831	—	—	1,831	6.7 %
Delhi Field	2,133	—	1,427	3,560	13.1 %
Total Proved	12,128	61,505	4,728	27,107	100.0 %

(1) Equivalent oil reserves are defined as six Mcf of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per Mcf and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Internal Controls Over Reserves Estimation Process and Qualifications of Technical Persons with Oversight for the Company's Overall Reserve Estimation Process

Our policies regarding internal controls over reserves estimates require such estimates to be prepared by an independent petroleum engineering firm under the supervision of our internal reserve engineering team, which includes our Chief Operating Officer ("COO"), J. Mark Bunch. Our internal reserve engineering team has a combined experience of over 80 years in Petroleum Engineering. Our COO, the person responsible for overseeing the preparation of our reserves estimates, has a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, is a registered Professional Engineer in the State of Texas (No. 86704), has over 40 years of oil and natural gas experience including large independents and financial firm services for projects and acquisitions. Our Board of Directors also has oversight of our reserve estimation process and contains a Reserves Committee with William Dozier, an independent director who is a Registered Professional Engineer in the State of Texas (No. 47279) with experience in energy company reserve evaluations. Such reserve estimates comply with generally accepted petroleum engineering and evaluation principles, definitions, and guidelines as established by the SEC.

The reserves information in this filing is based on estimates prepared by CG&A and D&M. The person responsible for the preparation of the reserve report at CG&A is W. Todd Brooker, P.E., President. Mr. Brooker received a Bachelor of Science degree in Petroleum Engineering in 1989 from the University of Texas at Austin and is a registered Professional Engineer in the State of Texas (No. 83462). Mr. Brooker joined CG&A in 1992 and has over 30 years of experience in engineering and geological services. The person responsible for the preparation of the reserve report at D&M is Dr. Dilhan Ilk, P.E., Executive Vice President. Dr. Ilk received a Bachelor of Science degree in Petroleum Engineering in 2003 from Istanbul Technical University and a Master's degree and Doctorate in Petroleum Engineering in 2005 and 2010, respectively, from Texas A&M University, and he has in excess of 15 years of experience in oil and natural gas reservoir studies and evaluations and is a licensed Professional Engineer in the state of Texas (No. 139334).

We provide CG&A and D&M with our property interests, production, current operating costs, current production prices, estimated abandonment costs and other information in order for them to prepare the reserve estimates. This information is reviewed by our senior management team and designated operations personnel to ensure accuracy and completeness of the data prior to submission to the reserve engineers. The scope and results of CG&A's and D&M's procedures, as well as their professional qualifications, are summarized in the letters included as Exhibit 99.1 and Exhibit 99.2, respectively, to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

During the year ended June 30, 2025 our proved undeveloped ("PUD") reserves changed as follows:

Proved undeveloped reserves:	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total Reserves (MBOE)[(1)]
June 30, 2024	3,956	11,249	1,914	7,745
Revisions of previous estimates	(921)	(6,952)	(1,467)	(3,547)
Improved recovery, extensions and discoveries	789	222	47	873
Transfers	(423)	(920)	(82)	(658)
June 30, 2025	3,401	3,599	412	4,413

[(1)] Equivalent oil reserves are defined as six Mcf of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per Mcf and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Our PUD reserves were 4.4 MMBOE as of June 30, 2025, with related future development costs of approximately $75.1 million, which are primarily associated with Chaveroo Field and Williston Basin and to a lesser extent our SCOOP/STACK properties, where we hold a smaller average net working interest. Extensions of 0.9 MMBOE are primarily associated with new wells at Chaveroo Field. Transfers of 0.7 MMBOE are associated with twelve gross SCOOP/STACK wells and four gross Chaveroo wells drilled, completed and placed online during fiscal 2025. The net downward revisions were due primarily to adjustments made to the timing in the Williston Basin development plan resulting in the roll-off of PUDs expected to be developed beyond five years. Under SEC reporting requirements, our PUD reserves include only those reserves in which the Company has current plans to develop within five years. See "*Drilling and Present Activities*" below for a further discussion of our expected development of the PUDs associated with SCOOP/STACK, the Chaveroo Field and Williston Basin.

Drilling and Present Activities

Currently, none of our oil and natural gas properties are operated by us. We therefore rely on information from our operators regarding near-term drilling programs. There are no plans to drill new wells in fiscal year 2026 in the Jonah Field, the Barnett Shale, Delhi Field and the Hamilton Dome Field. At this time, operators of our properties at Williston Basin, Hamilton Dome Field, Delhi Field and TexMex are periodically running workover rigs focusing on projects to return wells to production that have experienced mechanical issues.

At SCOOP/STACK, we currently expect five gross wells to be brought online during fiscal year 2026. Additionally, as our third-party operators continue to be active around our acreage, we would expect additional wells to be drilled and/or completed. At the Chaveroo Field, we expect to have drilling permits in hand for the next round of six wells before the end of the third quarter of fiscal 2026 and the final decision by us and our partner as to timing for spudding these wells will be made based on oil prices and completed well costs at that time.

For further discussion, see "Capital Expenditures" within Item 7. *Management's Discussion and Analysis of Financial Conditions and Results of Operations*.

Production volumes, average sales price and average production costs

The following table summarizes our crude oil, natural gas, and natural gas liquids production volumes, average sales price per unit and average daily production on an equivalent basis for the periods indicated:

	Years Ended June 30,					
	2025		2024		2023	
	Volume	Price	Volume	Price	Volume	Price
Production:						
Crude oil (MBBL)						
TexMex	17	$ 63.68	—	$ —	—	$ —
SCOOP/STACK	144	70.90	71	79.77	—	—
Chaveroo Field	64	63.49	27	77.90	—	—
Jonah Field	28	64.50	34	78.51	36	84.58
Williston Basin	130	63.56	146	73.97	144	79.38
Barnett Shale	8	65.65	9	75.01	9	76.12
Hamilton Dome Field	138	57.97	142	65.18	149	65.18
Delhi Field	236	72.33	279	79.46	319	81.57
Other	1	71.38	1	78.79	2	88.03
Total	766	$ 66.71	709	$ 75.38	659	$ 77.46
Natural gas (MMCF)						
TexMex	71	$ 2.64	—	$ —	—	$ —
SCOOP/STACK	1,297	3.34	532	2.46	—	—
Chaveroo Field	—	—	12	2.17	—	—
Jonah Field	3,081	2.94	3,448	3.55	3,675	10.63
Williston Basin	103	2.38	86	1.72	96	4.48
Barnett Shale	3,855	2.51	4,165	1.87	5,337	4.55
Other	2	1.86	—	—	1	4.66
Total	8,409	$ 2.80	8,243	$ 2.61	9,109	$ 7.00
Natural gas liquids (MBBL)						
TexMex	—	$ —	—	$ —	—	$ —
SCOOP/STACK	69	23.16	30	23.16	—	—
Chaveroo Field	—	—	1	21.93	—	—
Jonah Field	34	29.32	38	28.67	36	34.76
Williston Basin	24	19.91	20	21.85	24	27.23
Barnett Shale	216	27.86	233	27.61	274	32.54
Delhi Field	71	30.08	80	27.91	81	34.95
Other	—	—	—	—	1	26.15
Total	414	$ 27.11	402	$ 27.13	416	$ 32.86
Equivalent (MBOE)[(1)]						
TexMex[(2)]	29	$ 44.02	—	$ —	—	$ —
SCOOP/STACK[(3)]	429	37.64	190	40.43	—	—
Chaveroo Field[(3)]	64	63.49	30	72.10	—	—
Jonah Field	576	20.61	647	24.76	685	63.37
Williston Basin	171	52.43	180	63.10	184	68.12
Barnett Shale	867	18.74	936	15.93	1,173	28.89
Hamilton Dome Field	138	57.97	142	65.18	149	65.18
Delhi Field	306	62.56	359	68.03	400	72.13
Other	2	53.03	1	78.79	2	73.71
Total	2,582	$ 33.25	2,485	$ 34.56	2,593	$ 49.56
Average daily production (BOEPD)[(1)]						
TexMex[(2)]	79		—		—	
SCOOP/STACK[(3)]	1,175		519		—	
Chaveroo Field[(3)]	175		82		—	
Jonah Field	1,578		1,768		1,877	
Williston Basin	468		492		504	
Barnett Shale	2,375		2,557		3,214	
Hamilton Dome Field	378		388		408	
Delhi Field	838		981		1,096	
Other	8		3		5	
Total	7,074		6,790		7,104	

(1) Equivalent oil reserves are defined as six Mcf of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per Mcf and NGL prices per barrel often differ significantly from the equivalent amount of oil.

(2) Average daily production presented in the table above represents our fiscal year production divided by 365 days in the year for fiscal years 2025 and 2023. At TexMex, our average daily production since TexMex's acquisition date of April 14, 2025 through June 30, 2025, was 0.4 MBOEPD.

(3) Average daily production presented in the table above represents our fiscal year production divided by 366 days in the year for fiscal year 2024. At SCOOP/STACK and Chaveroo Field, our average daily production since SCOOP/STACK's acquisition date of February 12, 2024 and first production at Chaveroo Field beginning February 2024 through June 30, 2024, was 1.4 MBOEPD and 0.2 MBOEPD, respectively.

The following table summarizes our production costs, and production costs per unit for the periods indicated:

Production costs (in thousands, except per BOE)	Years Ended June 30, 2025 Amount	2025 per BOE	2024 Amount	2024 per BOE	2023 Amount	2023 per BOE
Total lease operating costs[1]						
TexMex	$ 1,189	$ 41.47	$ —	$ —	$ —	$ —
SCOOP/STACK	4,442	10.35	1,647	8.71	—	—
Chaveroo Field	869	13.58	462	15.40	—	—
Jonah Field	8,470	14.73	9,101	14.09	12,350	18.03
Williston Basin	5,063	29.61	5,235	29.08	5,581	30.42
Barnett Shale[2]	13,217	15.25	14,695	15.68	20,756	17.70
Hamilton Dome Field	5,479	39.61	5,722	40.37	5,574	37.45
Delhi Field	10,604	34.59	11,390	31.76	15,275	38.22
Other	5	2.41	21	9.10	9	3.35
Total	$ 49,338	$ 19.11	$ 48,273	$ 19.43	$ 59,545	$ 22.96

(1) Total lease operating costs include lifting costs; workover expenses; and gathering, transportation, processing and other expense.

(2) Barnett Shale lease operating costs for the fiscal year ended June 30, 2025 contains a $1.9 million credit from one of our operators due to a joint venture audit, see "Results of Operations" within Item 7. *Management's Discussion and Analysis of Financial Conditions and Results of Operations.*

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we own a working interest as of June 30, 2025.

	Company Operated Gross	Company Operated Net	Non-Operated Gross	Non-Operated Net	Total Gross	Total Net
Oil	—	—	867	217.8	867	217.8
Natural gas	—	—	1,372	255.7	1,372	255.7
Total	—	—	2,239	473.5	2,239	473.5

Acreage

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2025. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would allow production of oil and natural gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities whether or not the acreage contains proved reserves.

Field[1]	Developed Acreage Gross	Developed Acreage Net	Undeveloped Acreage Gross	Undeveloped Acreage Net	Total Gross	Total Net
TexMex, Louisiana, Texas, and New Mexico	27,789	11,220	—	—	27,789	11,220
SCOOP/STACK, Oklahoma	101,120	4,010	2,560	143	103,680	4,153
Chaveroo Field, New Mexico	1,120	560	3,408	1,704	4,528	2,264
Jonah Field, Wyoming	5,280	956	—	—	5,280	956
Williston Basin, North Dakota	124,800	37,258	13,440	3,996	138,240	41,254
Barnett Shale, Texas	123,777	20,918	—	—	123,777	20,918
Hamilton Dome Field, Wyoming	5,908	1,389	—	—	5,908	1,389
Delhi Field, Louisiana	9,126	2,180	4,510	1,077	13,636	3,257
Total[2]	398,920	78,491	23,918	6,920	422,838	85,411

(1) Except for our undeveloped acreage in the SCOOP/STACK, Oklahoma, which will expire in 2026 if we do not establish production in paying quantities on the units in which such acreage is included to maintain the lease and our acreage at the Williston Basin, North Dakota (see expiration table below), all acreage, including any undeveloped, nonproductive or undrilled acreage, is held by existing production as long as continuous production is maintained in the unit.

(2) This table excludes acreage attributable to small overriding royalty interests retained in various formations in the Texas Giddings Field area. Except for de minimis production that began on two leases during late fiscal year 2019. It does not currently appear likely that we will obtain any significant value from these interests and no reserves have been assigned to any of the Giddings' interests.

The table below reflects our net undeveloped acreage in Williston Basin, North Dakota as of June 30, 2025 that will expire each year if we do not establish production in paying quantities on the units in which such acreage is included to maintain the lease:

Fiscal Year	Net Acreage Expiration[(1)]
2026	860
2027	—
2028	—
2029	—
2030 & beyond	389
	1,249

(1) Excluded 2,747 net acres held by existing production as long as continuous production is maintained in the unit.

Markets and Customers

Our production is marketed to third parties in a manner consistent with industry practices. In the United States market where our properties are operated, crude oil, natural gas, and NGLs are readily transportable and marketable. In the Jonah Field, we take our natural gas and NGL working interest production in-kind and market separately to purchasers on six-month contracts for natural gas and to Enterprise Products Partners L.P. for NGLs. We do not currently market our share of oil, natural gas, or NGLs production from any other field separately from the operators' shares of production. Although we have the right to take our working interest production in-kind, we are currently selling our production through the field operators pursuant to the delivery and pricing terms of their sales contracts. Under such arrangements, we typically do not know the identity of the buyers.

As a non-operator, we are highly dependent on the success of our third-party operators and the decisions made in connection with their operations. With the exception of the Jonah Field, our third-party operators sell our oil, natural gas, and NGLs to purchasers, collect the cash, and distribute the cash to us. In the year ended June 30, 2025, three individual operators, Denbury (ExxonMobil), Diversified, and Foundation, each accounted for more than 10% of our total revenues, collectively representing approximately 51% of our total revenues for the year. In the year ended June 30, 2024, four individual operators, Denbury, Diversified, Foundation and Merit, each accounted for more than 10% of our total revenues, collectively representing approximately 69% of our total revenues for the year.

The loss of a purchaser at any of our major producing properties or disruption to pipeline transportation from these fields could adversely affect our net realized pricing and potentially our near-term production levels.

Market Conditions

Prices we receive for crude oil, natural gas, and NGLs are influenced by many factors that are beyond our control, the exact effect of which is difficult to predict. The oil and natural gas industry is a global market impacted by many factors, such as government regulations, particularly in the areas of tariffs, trade sanctions, taxation, energy, climate change and the environment, geopolitical instability and armed conflicts (including between Russia and Ukraine and in the Middle East between Israel and Gaza), demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

Competition

The oil and natural gas industry is highly competitive for prospects, acreage, and capital. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staff and greater capital resources. Competitors are national, regional, or local in scope and compete on the basis of financial resources, technical prowess or local knowledge. The principal competitive factors in our industry are expertise in given geographical areas and geologic systems and the ability to efficiently conduct operations, achieve technological advantages, identify and acquire economically producible reserves, and obtain capital at rates that allow economic investments.

Risk Management

We are exposed to certain risks relating to our ongoing business operations, including commodity price risk. In accordance with our company strategy and the covenants under the Senior Secured Credit Facility, derivative instruments are occasionally utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivative instruments available, historically we have used costless collars, stand alone put options, fixed-price swaps and basis swaps to attempt to manage price risk. Costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the settlement price under the agreement exceeds the ceiling and payments from the counterparties if the settlement price under the agreement is below the floor. Stand alone put options are floors that are purchased for a cost and provide that counterparties make payments to us if the settlement price is below the established floor. The fixed-price swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the fixed-price swap agreement. The basis swaps agreements effectively lock in a price differential between regional prices (i.e., Inside FERC's Northwest Pipeline Corp Rocky Mountains) where the product is sold and the relevant pricing index under which the natural gas production is hedged (i.e., NYMEX Henry Hub).

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. We will continue to evaluate the benefit of employing derivatives in the future. Our hedge strategies and objectives may change as our operational profile changes. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and Note 7, *"Derivatives"* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* for additional information.

Government Regulation

As an oil and natural gas exploration and production company, our interests are subject to numerous legal requirements.

Regulation of Oil and Natural Gas Production

Federal, state and local authorities have promulgated extensive rules covering oil and natural gas exploration, production and related operations. Those regulations require our third-party operator to obtain permits, post bonds and submit reports. They also may address conservation, including unitization or pooling of oil and natural gas properties, well locations, the method of drilling and casing wells, surface use and restoration of properties where wells are drilled, sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce and to limit the number of wells or the locations at which we can produce. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any applicable legal requirements may result in substantial penalties. Because such regulations are frequently amended or reinterpreted, we are unable to predict future compliance costs or impacts. Significant expenditures may be required to comply with governmental laws and regulations, however, and may have a material adverse effect on our financial condition and results of operations.

Regulation of Transportation of Oil and Natural Gas

The prices for crude oil, condensate and natural gas liquids and natural gas are negotiated and not currently regulated. However, Congress, which has been active in oil and natural gas regulation, could impose price controls in the future.

Our sales of crude oil and natural gas are affected by the availability, terms and cost of transportation. The Federal Energy Regulatory Commission ("FERC") primarily regulates interstate oil and natural gas transportation rates. In some circumstances, FERC regulations also may affect intrastate pipelines. In addition, states may impose on intrastate pipelines various obligations relating to such matters as safety, environmental protection, nondiscriminatory take and pay rates. The basis for intrastate oil and natural gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to such matters, vary from state to state. To the extent effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil and natural gas transportation rates will not affect our business in any way that is of material difference from those of our competitors who are similarly situated.

Environmental Matters

Our properties are subject to extensive and changing federal, state and local laws and regulations relating to the protection of the environment, worker safety and human health. Such requirements may address:

- the generation, storage, handling, emission, transportation and disposal of materials;
- reclamation or remediation of sites, including former operating areas;
- the acquisition of a permit or other authorization;
- air emissions;
- protection of water supplies;
- limits on construction, drilling and other activities in wilderness or other environmentally sensitive areas; and
- assessment of environmental impacts.

Failure to comply with such requirements may result in a variety of sanctions, including fines, administrative orders and injunctions. In addition, issuing authorities may revoke, adversely condition or deny permits necessary for the operations of our operators. In the opinion of management, our properties are in substantial compliance with applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general. Significant environmental requirements that may affect the operations of our operators are described below.

The Comprehensive Environmental, Response, Compensation, and Liability Act ("CERCLA") and comparable state statutes impose strict liability, and in some cases joint and several liability, on owners and operators of sites and on persons who arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for neighboring landowners or other third parties to also file claims for personal injury and property damage allegedly caused by any hazardous substances released into the environment. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," the operations performed by our operators do entail handling other chemicals that may be subject to the statute. In addition, state laws affecting our properties may impose cleanup liability relating to petroleum and petroleum related products. The Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste." Violations may result in substantial fines. Although RCRA currently classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous, thereby subjecting the operations of our operators to more stringent handling and disposal requirements. In some circumstances, moreover, RCRA authorizes both the federal government and private persons to seek injunctions requiring the cleanup of wastes, whether hazardous or non-hazardous.

The Endangered Species Act ("ESA") protects fish, wildlife and plants that are listed as threatened or endangered. Under the ESA, exploration and production operations may not significantly impair or jeopardize a protected species or its habitat. The ESA provides for criminal penalties for willful violations. The operations or our operators also may be subject to other statutes that protect animals and plants such as the Migratory Bird Treaty Act. Although we believe that our properties are in compliance in all material respects with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our third-party operators) to significant expenses to modify operations, could force discontinuation of certain operations altogether and could limit the locations our third-party operators may utilize in the future.

The Clean Air Act ("CAA") is the comprehensive federal law addressing sources of air emissions. Oil and natural gas production and natural gas processing operations are among the many source categories subject to the CAA. Regulated emissions from oil and natural gas operations include sulfur dioxide, volatile organic compounds ("VOCs") and hazardous air pollutants such as benzene, among others.

In particular, the Environmental Protection Agency ("EPA") announced regulations in December 2023 that imposed more comprehensive restrictions on emissions of methane (a greenhouse gas) and VOCs from new, existing, and modified facilities in the oil and gas sector (such as wells and storage tank batteries). Among other things, the rule set new emissions standards for certain equipment; required routine monitoring for and repair of leaks at well sites, centralized production facilities, and compressor stations; limited flaring from existing oil wells; and prohibited flaring from new oil wells. EPA also established a "Super Emitter Program" to authorize third parties to detect "super emitter events" at operators' sites and report them to EPA. The regulations did provide phase-in periods for certain requirements, while State plans for existing sources were due 24 months after the rule's effective date. States were given the option of either adopting the rule's presumptive standards or developing their own requirements that are at least as strict as EPA's. In 2024, however, EPA agreed to reconsider certain technical aspects of the regulations. And in 2025, EPA announced it was conducting a more comprehensive review. The results of the reconsideration are uncertain. But if the regulations remain as promulgated in December 2023, or if future such requirements requiring the installation of more sophisticated pollution control equipment are adopted, they could have a material adverse impact on our business, results of operations and financial condition.

The Clean Water Act (the "CWA") is the primary federal law controlling the discharge of produced waters and other pollutants into waters of the United States. Permits must be obtained for such discharges and to conduct construction activities in waters and wetlands. Some states also require permits for discharges or operations that may impact groundwater.

The CAA, CWA and comparable state statutes authorize civil, criminal and administrative penalties for violations. Further, the CWA and Oil Pollution Act may impose liability on owners or operators of onshore facilities that impact surface waters.

Pursuant to the Safe Drinking Water Act, the EPA (or an authorized state) regulates the construction, operation, permitting, and closure of injection wells used to place oil and natural gas wastes and other fluids underground for enhanced hydrocarbon recovery, storage or disposal. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Underground injection associated with oil and gas operations, particularly the disposal of produced water, has been linked in some cases to localized earthquakes. This in turn has led to new legislative and regulatory initiatives, which have the potential to restrict injection in certain wells or limit operations in certain areas.

Certain of the oil and natural gas production in which we have an interest is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection into the formation of water, sand and chemicals under pressure to stimulate production. From time to time, legislation has been proposed in the United States Congress to repeal the Safe Drinking Water Act's exemption for hydraulic fracturing from the definition of "underground injection" and to require federal permitting of hydraulic fracturing. If ever enacted, such legislation would add to costs for hydraulic fracturing.

Scrutiny of hydraulic fracturing activities continues in other ways. Several states where our properties are located have proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities likewise have enacted bans on hydraulic fracturing. We cannot predict whether any other legislation restricting hydraulic fracturing will be enacted and if so, what its provisions would be. If additional levels of regulation and permits were to be required through the adoption of new laws and regulations at the federal, state or local level, it could lead to delays, increased operating costs and process prohibitions that could materially adversely affect our revenue and results of operations.

The National Environmental Policy Act ("NEPA") requires federal agencies to assess the environmental effects of their proposed actions prior to making decisions. Among the broad range of actions covered by NEPA are decisions on permit applications and federal land management. Many of the activities of our third-party operators involve federal decisions subject to NEPA. Such federal actions may trigger robust NEPA review, which could lead to delays and increased costs that could materially adversely affect our revenues and results of operations. In response to recent court decisions, and direction from the second Trump Administration to expedite permit approvals, federal agencies started updating their NEPA procedures in 2025, but the long-term effects of those revisions are uncertain. In the absence of precedents, application of the new procedures may be unclear, and nongovernmental organizations are expected to bring legal challenges, which could adversely affect the assessment of projects ranging from oil and gas leasing to development on public and Indian lands.

Climate Change

Climate change has become a major public concern and policy issue in the United States and around the world. Much of the debate has focused on greenhouse gas ("GHG") emissions from oil and natural gas, particularly carbon dioxide and methane.

In the United States, there is no comprehensive federal regulatory statute addressing climate change, although Congress does periodically consider such measures. At the federal level, the United States therefore has primarily addressed climate change through executive actions and regulatory initiatives pursuant to existing statutes. These have included participation in international agreements on climate change, presidential commitments to reduce greenhouse gas, various executive orders limiting land available for oil and gas leasing, and Clean Air Act rules (such as the regulation announced in December 2023 to reduce methane emissions from the oil and gas sector). In his second Administration, President Trump has reversed, or indicated that he intended to reverse, many of those initiatives. Even if those efforts are successful, several states have already implemented or are considering programs to reduce GHG emissions. These include cap and trade programs, promotion of alternative forms of energy, transportation standards and restrictions on particular GHGs. New Mexico, for example, is requiring oil and gas operators to capture 98% of their produced natural gas by December 31, 2026, and is limiting most venting and flaring. Such efforts are expected to continue in some states. To the extent that new climate change measures are adopted, our business may be adversely impacted.

In addition, recent court decisions have left open the question of whether tort claims alleging property damage may proceed under state common law against entities responsible for GHG emissions. Thus, there is some litigation risk for such claims.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources, for example, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products may become less desirable in the market with such government intervention. In 2022, the United States enacted the Inflation Reduction Act that, among other things, created a series of financial incentives intended to discourage use of oil and natural gas (including imposing a fee on methane emissions) and to promote alternative sources of energy. Pursuant to that Act, EPA announced a rule in 2024 that would have implemented the program for collecting the annual "Waste Emissions Charge" on certain excess methane emissions from oil and gas facilities. By statute, the charge would have been $900 per metric ton of methane for 2024, $1,200 per metric ton for 2025, and $1,500 per metric ton each year thereafter. But in 2025 Congress invalidated the EPA's rule and postponed the methane reduction charge to 2034. We cannot predict with any certainty at this time how such market-based climate incentives may affect the operations of our oil and natural gas properties.

Various studies on climate change indicate that extreme weather conditions and other risks may occur in the future in the areas where we operate. Although we have not experienced any material impact from such extreme conditions to date, no assurance can be given that they will not have a material adverse effect on our business in the future.
See discussion captioned "Government regulation and liability for oil and natural gas operations and environmental matters may adversely affect our business and results of operations" in Item 1A. *Risk Factors*.

Insurance

We maintain insurance on our oil and natural gas properties and operations for risks and in amounts customary in the industry. Such insurance includes, but is not limited to, general liability, excess liability, control of well, operators extra expense, casualty, fraud, and directors and officer's liability coverage. Additionally, we maintain industry-standard cybersecurity insurance to provide protection against cybersecurity risk. Not all losses are insured, and we retain certain risks of loss through deductibles, limits, and self-retentions. We do not carry business interruption or lost profits coverage.

Human Capital, Sustainability, and ESG

Employees

As of June 30, 2025, we had eleven full-time employees, not including contract personnel and outsourced service providers. Due to our current focus on non-operating properties, our staff is disproportionately weighted towards higher wage professionals. We believe that we have positive relations with our employees. Our team is broadly experienced in oil and natural gas operations, development, acquisitions, and financing. We follow a strategy of outsourcing most of our IT services, human resources, administrative, and other non-core functions. For our full-time employees, our benefits package, as determined by our Board of Directors, includes medical, dental, and vision insurance, short-term disability, 401(k) contributions based on a portion of the employee's base salary, short and long-term performance-based and service-based incentive pay (i.e., annual bonuses and stock awards), and paid time off.

Our workforce is provided with regular training and is expected to sign an acknowledgement regarding our policies and disclosures which include, but are not limited to, the Corporate Sustainability Report ("CSR"), employee handbook, human rights, code of ethics, health and safety, emergency procedures, conflicts of interest, insider trading, bribery, kickbacks and discrimination.

Sustainability and ESG

In fiscal year 2021-2022, we laid the foundation for our sustainability efforts by creating an Environmental Social Governance ("ESG") Task Force.

The Task Force formalized our existing ESG programs, proposed and implemented new ESG initiatives, monitored adherence to our internal and third-party sustainability standards, and provided public disclosures for our stakeholders. Its efforts led to the publication of Evolution's first CSR. Our most recent edition was published in November 2023. This report is accessible on our website at www.evolutionpetroleum.com. Further emphasizing our commitment to corporate responsibilities, our Board formed a dedicated Sustainability Committee in fiscal year 2023 which is now responsible for overseeing our ESG initiatives.

We are committed to high standards of conduct and ethics to contribute to the sustainability of our business. Our core values are the base to support our strategy and long-term success. We believe integrity is paramount and we are committed to developing and producing energy resources in environmentally, socially, and ethically respectful and responsible ways. Our people are critical to our success and as such we promote and maintain a safe and inclusive work environment. We strategically plan for the long-term and strive to maintain capital discipline, stakeholder transparency, and continuous focus on returning capital to shareholders.

We work with third-party operators that share our desire to operate and work responsibly, particularly for the natural environments in which they operate. As a non-operator of our current properties, we do not have direct control over environmental initiatives at a property-level. However, we believe it is important to partner with third-party operators that share our core values and are committed to being environmental stewards as they responsibly produce energy resources. We recognize that the expectations, requirements, and responsibilities of operators regarding safeguarding the environment and environmental stewardship continue to evolve. We are, and will continue to be, committed to supporting our third-party operators as they respond to these expectations, requirements, and responsibilities.

We maintain a hotline which operates 24/7/365 and allows anonymous and confidential reporting for employees, consultants, partners, and contractors, including the ability to report concerns or violations of our policies through the phone or internet (Phone: 877-628-7489 / Website: www.epm.alertline.com).

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at www.evolutionpetroleum.com. These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, or calling (713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk Factors

Our business involves a high degree of risk. Our ownership interest in oil and natural gas properties consists of non-operated working, revenue, and/or royalty interests. We do not operate any of our oil and natural gas properties nor do we do have any employees or contractors in the field. Our risks associated with oil and natural gas operations affect us indirectly through our ownership in non-operated working interests where we proportionately share in the costs and liabilities of operating such properties.

If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition, or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider to be immaterial also may adversely affect us.

Risks Related to Our Business:

A substantial or extended decline in oil, natural gas and NGL prices may adversely affect our business, financial condition, results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil, natural gas and NGLs significantly influences our revenue, profitability, access to capital, capital spending, and future rate of growth. At June 30, 2025, approximately 45% of our proved reserves were oil reserves, 38% were natural gas and 17% were NGLs. Oil, natural gas and NGLs are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas, and NGLs have been volatile and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to the following:

- changes in global supply and demand for oil and natural gas;
- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the conflict between Ukraine and Russia and the conflict between Israel and Gaza, and acts of terrorism or sabotage;
- the ability and willingness of the members of OPEC+ to agree and maintain oil price and production controls;
- the price and quantity of imports of foreign oil and natural gas;
- energy transition away from hydrocarbons in response to governmental, scientific, and public concern over the threat of climate change arising from greenhouse gas emissions;
- the relative strength or weakness of the U.S. dollar compared to other currencies;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals of regional, domestic, and international transportation availability;
- weather conditions, natural disasters, and seasonal trends;
- domestic and foreign governmental regulations, including embargoes, sanctions, tariffs, and environmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price, availability and use of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) contracts at market-based prices. A decline in oil, natural gas, and NGL prices will reduce our cash flows, borrowing ability, the present value of our reserves, and our ability to develop future reserves. We may be unable to obtain the needed capital or financing on satisfactory terms. Low oil, natural gas, and NGL prices may also reduce the amount of oil, natural gas, and NGL that we can produce economically, which could lead to a decline in our oil, natural gas and NGL reserves. Generally, we hedge substantially less than all of our anticipated oil and natural gas production and typically limited to what is required by our Senior Secured Credit Facility. To the extent that we have not hedged production, any significant and extended decline in oil, natural gas, and NGL prices may adversely affect our financial position.

Our existing developed oil, natural gas and NGL production will decline; we may be unable to acquire or develop the additional oil and natural gas reserves that are required in order to sustain our production and business operations.

The volume of production from developed oil, natural gas, and NGL properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Environmental issues, operating problems, or lack of extended future investment in any of our properties would cause our net production of oil, natural gas, and NGLs to decline significantly over time, which could have a material adverse effect on our financial condition.

The types of resources we focus on have substantial operational risks.

Our business plan focuses on the acquisition and development of known resources in partially depleted, naturally fractured, or low permeability reservoirs. Our TexMex, Chaveroo Field, Hamilton Dome Field and Delhi Field properties produce from relatively shallow reservoirs, while our SCOOP/STACK, Jonah Field, Williston Basin and Barnett Shale properties produce from deeper reservoirs. Shallower reservoirs usually have lower pressure, which generally translates into lower reserves volumes in place. Deeper reservoirs have higher pressures and usually more reserves volumes in place, but capturing those reserves often comes at increased drilling and completion costs and risks and, generally, a higher rate of initial production decline. Low permeability reservoirs require substantial stimulation for development of commercial production. Naturally fractured reservoirs require penetration of sufficient un-depleted fractures to establish commercial production. Depleted reservoirs require successful application of newer, or more expensive, technologies to produce incremental reserves. Our approach on the development and application of technologies on these different types of reservoirs could have a material adverse effect on our results of operations.

The CO_2-EOR project in the Delhi Field, operated by Denbury, a subsidiary of ExxonMobil, requires significant amounts of CO_2 reserves, development capital, and technical expertise, the sources of which to date have been committed by the operator. The operator's failure to manage these and other technical, environmental, operational, strategic, financial, and logistical risks may ultimately cause enhanced recoveries from the planned CO_2-EOR project to fall short of our expectations in volume and/or timing. Such occurrences could have a material adverse effect on our results of operations and financial condition.

We have limited control over the activities on properties we do not operate.

All of our property interests are operated by others. As a result, we have limited ability to influence or control the operations or future development of such properties, including compliance with environmental, safety, and other standards, or the amount or timing of capital or other expenditures that we will be required to fund with respect to such properties. Operators of these properties may act in ways that are not in our best interest. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, result in lower production, and materially and adversely affect our financial condition and results of operations.

We will be subject to risks in connection with acquisitions.

We periodically evaluate acquisitions of reserves, properties, prospects, leaseholds, and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including, but not limited to:

- recoverable reserves;
- future oil, natural gas, and NGL prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;

- validity of the seller's title to properties, which may be less than expected at closing; and
- potential environmental issues, litigation, and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable at the ground surface or otherwise when an inspection is performed. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Moreover, in the event of such an acquisition, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions and, importantly, that our assumptions regarding future oil and natural gas prices, differentials, reserves, or production could prove materially inaccurate and have a material adverse effect on our financial condition, results of operations, or cash flows.

Our inability to complete acquisitions at our historical rate and at appropriate prices that support our long-term strategy could negatively impact our growth rate and stock price.

One of our key strategies is growth through acquisition of low decline, long-life oil and natural gas properties. Our ability to grow revenues, earnings and cash flow at or above our historic rates depends in part upon our ability to identify and successfully acquire and integrate oil and natural gas properties at appropriate prices, and to make appropriate investments that support our long-term strategy. We may not be able to consummate acquisitions at rates similar to the past, which could adversely impact our growth rate, our stock price, and our ability to maintain our dividends. Acquisitions are difficult to identify and complete for a number of reasons, including high valuations, competition among prospective buyers or investors, the availability of affordable funding in the capital markets and the need to satisfy applicable closing conditions.

We may encounter difficulties integrating newly acquired oil and natural gas properties or businesses.

Increasing our reserve base through acquisitions has been an important part of our business strategy. We may encounter difficulties integrating newly acquired oil and natural gas properties or businesses. In particular, we may face significant challenges in consolidating functions and integrating procedures, personnel, and business operations in an effective manner. The failure to successfully integrate such properties or businesses into our Company may adversely affect our business and results of operations. Any acquisition we make may involve numerous risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial costs to address unforeseen environmental and other liabilities arising out of the acquired businesses or assets;
- liabilities arising from the operation of the acquired businesses or assets before our acquisition;
- our lack of drilling or operational history in the areas in which the acquired business operates;
- customer or key employee loss from the acquired business;
- increased administration of new personnel;
- additional costs due to increased scope and complexity of our business;
- potential disruption of our ongoing business; and
- assumptions made on estimated development by the operator may not be accurate or may change.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties we currently own or that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as effectively as with acquisitions within our current footprint and expertise. We may not be successful in addressing these risks or any other problems encountered in connection with any acquisition we may make.

Oil and natural gas development, re-completion of wells from one reservoir to another reservoir, restoring wells to production, and drilling and completing new wells are speculative activities which involve numerous risks and substantial uncertain costs.

Our growth will be partially dependent upon the success of future development programs on our properties. Drilling for oil and natural gas and extracting NGLs and re-working existing wells involve numerous risks. The cost of drilling, completing, and operating wells is substantial and uncertain; drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors beyond our control, including, but not limited to:

- unexpected drilling conditions;
- pressure fluctuations or irregularities in reservoir formations;
- equipment failures or accidents;
- well blowouts and other releases of hazardous materials;
- inability to obtain or maintain leases on economic terms, where applicable;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services, and tubulars;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion and production techniques, such as Horizontal Drilling or CO_2 injection, do not guarantee that we will find and produce oil, natural gas and/or NGLs in economic quantities. Our future drilling, completion and production activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition.

We may also identify and develop prospects through a number of methods, some of which may include Horizontal Drilling or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. We cannot ensure that these projects can be successfully developed or that wells will, if drilled, encounter reservoirs of commercially productive oil or natural gas.

Our oil and natural gas reserves are only estimates and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values. Our reserves are only estimates that may prove to be inaccurate because of these inherent uncertainties. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot always be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves depend upon a number of variable factors. These factors include historical production from the area compared with production from other comparable producing areas, assumptions concerning effects of regulations by governmental agencies, future oil, natural gas, and NGL product prices, future operating costs, severance and excise taxes, development costs, workover costs, and remedial costs. Some or all of these assumptions utilized in estimating reserve volumes may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of reserves, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected from reserves may vary substantially depending on the timing and different engineers preparing reserves estimates.

Accordingly, reserve estimates may be subject to downward or upward adjustments. Actual production, revenue, and expenditures with respect to our reserves will likely vary from estimates; such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. Interest rates in effect vary from time to time based on risks associated with us or the oil and natural gas industry in general. The Standardized Measure does not necessarily correspond to market value.

Regulatory and accounting requirements may require substantial reductions in reporting proven reserves.

On a periodic basis, we review the carrying value of our oil and natural gas properties under the applicable rules of various regulatory agencies, including the SEC. Under the full cost method of accounting that we use, the after-tax carrying value of our oil and natural gas properties may not exceed the present value of estimated future net after-tax cash flows from proved reserves, discounted at 10%. Application of this "ceiling" test requires pricing future revenues at the previous 12-month average beginning-of-month price and requires a write-down of the carrying value for accounting purposes if the ceiling is exceeded. We may in the future be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend in part on the prices of oil and natural gas during the previous period and the effect of reserve additions or revisions and capital expenditures during such period. If a write-down is required, it would result in a current charge to our earnings but would not impact our current cash flow from operating activities. A large write-down could adversely affect our compliance with the current financial covenants under our Senior Secured Credit Facility, could limit our access to future borrowings under that facility, or require repayment of any amounts that might be outstanding at the time.

Our derivative activities could result in financial losses or could reduce our income.

Under the terms of our Senior Secured Credit Facility, we are required to hedge a certain portion of our anticipated oil and natural gas production for future periods when we reach a defined utilization percentage. We may also elect to hedge additional production volumes from time to time based upon our view of the attractiveness of commodity futures and the risks that downward price fluctuations might pose to our business plans. When we engage in hedging transactions, we may utilize costless collars, fixed price swaps or purchased floors to cost-effectively provide us with some protection against price changes. We have not historically designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our future derivative instruments. Derivative arrangements may also expose us to the risk of financial loss in some circumstances, including, but not limited to, if:

- actual production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative instrument and actual price received.

In addition, in a rising commodity price environment, derivative arrangements may limit the extent to which we might benefit from increases in prices of oil and natural gas and may expose us to cash margin requirements.

Operations to develop and produce oil and natural gas reserves and our growth plans require significant amounts of capital and our ability to access additional capital at acceptable costs is important if we are to fund our development, grow our reserves and production and execute our growth plans.

Cash flow from our production varies based on commodity prices and may decline along with nature declines in our production. As a consequence, our cash flow may not be sufficient to fund our ongoing or planned activities at all times. From time to time, we may require additional financing in order to fund operations, acquisitions, exploitation, and development activities. We have, for instance, accessed our Senior Secured Credit Facility on a routine basis, including, recently, to fund acquisitions. Subsequent to our TexMex Acquisition in April 2025 and the SCOOP/STACK Acquisitions in 2024, the borrowings outstanding on our Senior Secured Credit Facility at June 30, 2025 was $37.5 million. On June 30, 2025, we entered into a syndicated amended and restated credit facility with MidFirst as administrative agent and added a second lender. The commitment size of the Senior Secured Credit Facility was increased to $65.0 million from $50.0 million. We may not be able to further increase the total commitments by adding additional lenders in the future on terms that are favorable to us. Further, the size of our Senior Secured Credit Facility is influenced by many factors, including our production, reserves and prevailing views on future commodity prices, and it may decrease based on developments negatively impacting those and other factors. While ordinarily positive developments in such factors might increase the amount that lenders are willing to lend to us, we are currently at the limit of our two lenders to increase the size of our Senior Secured Credit Facility due to limitations that the lenders have on the loans they may extend to a single borrower. Additionally, access to debt and equity capital markets or other alternatives may also prove unavailable or unattractive at such times or in such amounts as we may require. If we are unable to access adequate capital at acceptable costs, it could adversely affect our ability to expend the necessary capital to replace our reserves, maintain our production and execute our business plans.

Government regulation and liability for oil and natural gas operations and environmental matters may adversely affect our business and results of operations.

Oil and natural gas operations are subject to extensive federal, state, and local government regulations, which may change from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas from wells below actual production capacity in order to conserve supplies of oil and natural gas. There are federal, state, and local laws and regulations addressing protection of human health and the environment that apply to the development, production, handling, storage, and transportation of oil, natural gas, and their by-products; the disposal of related wastes; the emission of CO_2, methane, and other greenhouse gases; the emission of volatile organic compounds; and the management of other substances and materials released, produced or used in connection with oil and natural gas operations. These laws and regulations may affect the costs, manner, and feasibility of operations by, among other things, requiring us to make significant expenditures in order to comply and restricting the areas available for oil and gas production. Failure to comply with these laws and regulations may result in substantial liabilities to third-parties or governmental entities. In addition, we may be liable for significant environmental damages and cleanup costs, without regard to fault, for releases of hazardous materials on or from property we own or operate, even if we did not cause or contribute to the release. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations, could have a material adverse effect on us, such as by imposing new emission controls, penalties, fines and/or fees, taxes and tariffs on carbon that could have the effect of raising prices to the end user and thereby reducing the demand for our products.

The risks arising out of the threat of climate change, including transition risks and physical risks, may adversely affect our business and results of operations.

The threat of climate change poses both transition risks and physical risks that could have a material adverse effect on us. Transition risks may arise from political and regulatory, legal, technological or financial changes as society tries to safeguard the climate, while physical risks may result from extreme weather events or other shifts in the natural world.

We have been facing increased political and regulatory risks as federal, state and local governments have adopted new measures to restrict sources of greenhouse gas emissions and promote energy alternatives, including the final EPA rule announced in December 2023 to reduce the emission of methane from oil and gas facilities. Many such measures have been proposed, and still more can be expected. From time to time, there are proposals to ban hydraulic fracturing of oil and natural gas wells and to remove more lands, both onshore and offshore, from new hydrocarbon production. Many other actions could be pursued such as more rigorous requirements for drilling and construction permits, stricter greenhouse gas emissions standards for both new and existing sources, further limits on construction of new pipelines, reinstatement of the ban on oil exports, enhanced reporting obligations, taxing carbon emissions and creating further incentives for use of alternative energy sources. These actions may cause operational delays or restrictions, increased operating costs and additional regulatory burdens.

Litigation risks are also increasing for oil and natural gas companies. A number of suits alleging, among other things, that oil and natural gas companies created public nuisances by producing fuels that contributed to climate change have been brought in state or federal court.

Technological changes may drive market demand for products other than oil and natural gas. Wider adoption of hybrid engines and electric cars, for example, would reduce demand for our products. At the same time, our capital and operating costs may increase if we need to add new emission reduction technologies.

There are also financial risks for the petroleum industry. It may become more difficult for us to access the capital markets if the threat of climate change discourages new investment. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect not to provide funding for fossil fuel energy companies. Limitation of investments in and financings for the energy industry could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The threat of climate change also may subject oil and natural gas operations and our business to severe weather or other natural hazards, such as flooding, drought, wildfires, and extreme temperatures. Any such event could halt production or exploration activities, damage equipment, disrupt transportation, reduce consumer demand and significantly increase our costs.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, financial condition and access to capital.

During the last few years, concerns over inflation, energy costs, volatile oil, natural gas, and NGL prices, geopolitical issues, the availability and cost of credit, the United States mortgage market, uncertainties with regard to European sovereign debt, the slowdown in economic growth in large emerging and developing markets, such as China, regional or worldwide increases in tariffs or other trade restrictions, and other issues have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on domestic and international financial markets and commodity prices. If uncertain or poor economic, business, or industry conditions in the United States or abroad remain prolonged, demand for petroleum products could diminish or stagnate, and production costs could increase. These situations have led to commodity price volatility and impact the price at which we can sell our oil, natural gas, and NGLs. Any sustained declines in crude oil, natural gas and NGL prices could affect our revenues, our operators ability to continue operations, and ultimately adversely impact our results of operations, liquidity and financial condition.

Events outside of our control, including a pandemic or broad outbreak of an infectious disease, such as the global outbreak of a novel strain of the coronavirus ("COVID-19"), may materially adversely affect our business.

We face risks related to pandemics, outbreaks, or other public health events that are outside of our control and could significantly disrupt our operators' operations and adversely affect our financial condition. In December 2019, COVID-19 was identified in Wuhan, China and rapidly spread around the world. This virus and its variants, and governmental actions to contain it, had material adverse economic impacts globally. These and other actions, among other things, impacted the ability of our employees and contractors to perform their duties, caused increased technology and security risk due to extended and company-wide telecommuting, and led to disruptions in our permitting activities and critical business relationships, and could do so in the future should another similar public health event occur. Additionally, governmental restrictions intended to contain COVID-19 or future pandemics have in the past, and may in the future, significantly impact economic activity and markets and dramatically reduce actual or anticipated demand for oil and natural gas, adversely impacting the prices we receive for our production. The severity and duration of any such events are uncertain and difficult to predict, as is the extent that such events may have on our business.

Our business could be negatively affected by security threats. A cyber-attack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation, and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing, and financial activities. We depend on digital technology to estimate quantities of oil and natural gas reserves, manage operations, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party operators. Our technologies, systems, networks, seismic data, reserves information, or other proprietary information, and those of our operators, vendors, suppliers, customers, and other business partners may become the target of cyber-attacks or information security breaches. Cyber-attacks or information security breaches could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could otherwise lead to the disruption of our business operations or other operational disruptions in our exploration or production operations. Cyber-attacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period and could lead to disruptions in critical systems or the unauthorized release of confidential or otherwise protected information. These events could lead to financial losses from remedial actions, loss of business, disruption of operations, damage to our reputation, or potential liability. Also, computers control nearly all of the oil and natural gas distribution systems in the United States and abroad. Computers are necessary to transport our oil and natural gas production to market. A cyber-attack directed at oil and natural gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. Cyber incidents have increased, and the United States government has issued warnings indicating that energy assets may be specific targets of cybersecurity threats. Our systems and insurance coverage for protecting against cybersecurity risks may not be sufficient. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

The oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of oil, natural gas, or well fluids, fires, formations with abnormal pressures, hurricanes and storms, flooding, pollution, releases of toxic gas, and other environmental hazards and risks, which can result in (1) damage to or destruction of wells and/or production facilities, (2) damage to or destruction of formations, (3) injury to persons, (4) loss of life, or (5) damage to property, the environment or natural resources. While we carry general liability, control of well, and operator's extra expense coverage typical in our industry, we are not fully insured against all risks incidental to our business. Should we experience any losses, the costs of our premiums may rise, which could in turn reduce the amount of insurance we are able to carry.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers. The loss of one or more key personnel could have a material adverse effect on our operations. In particular, our future success is dependent upon the abilities of our executive officers to source, evaluate, and close deals, raise capital, and oversee our development activities and operations. Presently, we are not a beneficiary of any key man life insurance.

Oilfield service and materials prices may increase, and the availability of such services and materials may be inadequate to meet our needs.

Our business plan to develop or redevelop oil and natural gas resources requires third-party oilfield service vendors and various material providers, which we do not control. We also rely on third-party carriers for the transportation and distribution of our oil and natural gas production. As our production increases, so does our need for such services and materials. Generally, we do not have long-term agreements with our service and materials providers. Accordingly, there is a risk that any of our service providers could discontinue providing services for any reason or we may not be able to source the services or materials we need. Any delay in locating, establishing relationships, and training our sources could result in production shortages and maintenance problems, resulting in loss of revenue to us. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelopment plans.

We may assume risks and financial responsibility for drilling and completing wells at our Chaveroo Field and Williston Basin properties if our third-party operator declines to drill wells and it or other joint interest owners elect not to participate.

As discussed elsewhere in this report, pursuant to agreements related to our interests in the Chaveroo Field and Williston Basin properties, we have the ability to propose to the operator a drilling plan for certain wells, which the operator may accept or reject. In the event the operator rejects our proposed drilling plan, we have the right to undertake all necessary activities to drill and complete the wells and related facilities in accordance with our proposed drilling plan. In the event we undertake to do so, and the operator and other joint interest owners elect not to participate, we will bear the entire liability and expense associated with drilling and completing the wells and related facilities, subject only to our right to recoup costs incurred on behalf of non-participating joint interest owners to the extent a well generates sufficient revenues to do so. We thus may be required to bear a share of such expenses to an extent that is disproportionate to our economic interest in the property. If we elect to proceed to drill and complete wells we have proposed and the operator has rejected, we also will bear many of the other risks highlighted elsewhere herein, including, without limitation, failing to find economic quantities of oil and natural gas, drilling accidents, potential environmental liabilities, unavailability of insurance at a reasonable cost to cover associated liabilities, and price increases and delivery delays for required drilling and completion equipment, products and services. Ongoing operations of any wells we elect to drill will be turned over to the operator of the property upon completion.

We cannot market the oil and natural gas that we produce without the assistance of third-parties.

The marketability of the oil and natural gas that we produce depends upon the proximity of our reserves and production to, and the capacity of, facilities and third-party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities necessary to make the products marketable for end use. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in, delay, or discontinuance could adversely affect our financial condition.

We face strong competition from larger oil and natural gas companies.

Our competitors include major integrated oil and natural gas companies, numerous larger independent oil and natural gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources. We may not be able to successfully conduct our operations, evaluate and select suitable properties, or consummate transactions in this highly competitive environment. Specifically, these larger competitors may be able to pay more for development projects and productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may be able to expend greater resources on hiring contract service providers, obtaining oilfield equipment, and acquiring the existing and changing technologies that we believe are, and will be, increasingly important to attaining success in our industry.

We have been, and in the future may become, involved in legal proceedings related to our properties or operations and, as a result, may incur substantial costs in connection with those proceedings.

From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our oil and natural gas properties and related operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our financial condition. Adverse litigation decisions or rulings may damage our business reputation.

Ownership of our oil and natural gas production and mineral rights depends on good title to our property.

Good and clear title to our oil and natural gas properties and mineral rights is important to our business. Although title reviews will generally be conducted prior to the purchase of most oil, natural gas, and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim. This could result in a reduction or elimination of the revenue received by us from such properties.

Unanticipated changes in effective tax rates or laws or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.

We are subject to tax by U.S. federal, state, and local tax authorities. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

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

For example, in previous years under previous Administrations, legislation has been proposed to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and natural gas exploration and production companies. Such proposed changes have included: (1) a repeal of the percentage depletion allowance for oil and natural gas properties; (2) the elimination of deductions for intangible drilling and exploration and development costs; (3) the elimination of the deduction for certain production activities; and (4) an extension of the amortization period for certain geological and geophysical expenditures. Under the previous Administration there was an increased risk of the enactment of legislation that alters, eliminates, or defers these or other tax deductions utilized within the industry, which could adversely affect our business, financial condition, results of operations, and cash flows.

On July 4, 2025, legislation commonly referred to as the "One Big Beautiful Bill Act" (OBBBA) was enacted, significantly changing existing U.S. tax law. The OBBBA includes numerous provisions, such as permanent full expensing of domestic research and experimental expenditures, 100% bonus depreciation, modification of business interest limitations, and various international tax provisions such as Base Erosion and Anti-Abuse Tax, Foreign-Derived Deduction Eligible Income and Net Controlled Foreign Corporations Tested Income. Changes in tax laws between Administrations could affect our business, financial condition, results of operations, and cash flows when compared to previous years.

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

Risks Associated with our Common Stock

Our stock price has been and may continue to be volatile.

Our common stock has a relatively low trading volume and the market price has been, and is likely to continue to be, volatile. The variance in our stock price makes it difficult to forecast the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- changes or fluctuations in the commodity prices of oil and natural gas;
- general conditions and trends in the oil and natural gas industry;
- redemption demands on institutional funds that hold our stock; and
- general economic, political, and market conditions.

Significant ownership of our common stock is concentrated in a small number of shareholders who may be able to affect the outcome of the election of our directors and all other matters submitted to our stockholders for approval.

As of June 30, 2025, our executive officers and directors, in the aggregate, beneficially owned approximately 3.4 million shares, or approximately 9.9% of our outstanding common stock and, based on recent filings with the SEC, we believe two large non-affiliated fund complexes owned in excess of 12% of the outstanding shares of our common stock. As a result, a significant percentage of our common stock is concentrated in the hands of relatively few shareholders. These shareholders could potentially exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring, or preventing any matter that requires shareholder approval, including a change in control of our company, impede a merger, consolidation, takeover, or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

The market for our common stock is limited and may not provide adequate liquidity.

Our common stock trades on the NYSE American. Trading volume in our common stock is relatively low compared to larger companies. Our holders may find it more difficult to sell their shares, should they desire to do so, based on the trading volume and price of our stock at that time relative to the quantity of shares to be sold.

If securities or industry analysts do not publish research reports about our business, or if they downgrade our stock, the price of our common stock could decline.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. To our knowledge, only two research analysts actively cover our company. The limited number of published reports by securities analysts could limit the interest in our common stock and negatively affect our stock price. We do not have any control over the research and reports these analysts publish or whether they will be published at all. If any analyst who does cover us downgrades our stock, our stock price could decline. If any analyst ceases coverage of our company or fails to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price to decline.

Our stated objective of returning cash to shareholders is subject to our ability to generate sufficient cash flows to pay dividends on our common stock and to repurchase shares of our common stock, as applicable, and we have, in the past, and may in the future, reduce or eliminate dividend payments and stock repurchases.

Our Board of Directors declared cash dividends on our common stock for the first time in December 2013 and we have declared and paid quarterly cash dividends since that time. Additionally, our Board of Directors has in the past approved stock repurchase programs pursuant to which we have expended $8.6 million to repurchase shares over such period. Although one of our primary objectives is to return cash to shareholders, we are not required to repurchase shares of common stock or to pay dividends thereon and may be contractually or legally prohibited from doing so at certain times. Further, even if we are legally and contractually permitted to do so and have available cash to do so, we may elect to reduce or suspend the payment of dividends or the repurchase of shares of common stock to preserve cash based on the current and future capital requirements of our business, our financial condition, the amount of funds legally available therefor, any contractual restrictions to which we are subject at such time, our expectations about future cash inflows and such other factors as our Board of Directors may consider relevant. Accordingly, there is no certainty that dividends will be declared by our Board of Directors or shares of common stock will be repurchased by us in the future.

There may be future sales or issuances of our common stock, which will dilute the ownership interests of stockholders and may adversely affect the market price of our common stock.

We may in the future issue additional shares of common stock, including securities that are convertible into or exchangeable for, or that represent the right to receive, common stock or substantially similar securities, which may result in dilution to our stockholders. In addition, our stockholders may be further diluted by future issuances under our equity incentive plans and/or our At-the-Market equity Sales Agreement. The market price of our common stock could decline as a result of future sales or issuances of a large number of shares of our common stock or similar securities in the market or the perception that such sales or issuances could occur.

Non-U.S. holders may be subject to U.S. income tax and withholding tax with respect to gain on disposition of the Company's common stock.

We believe we are a U.S. real property holding corporation. As a result, Non-U.S. holders that own (or are treated as owning under constructive ownership rules) more than a specified amount of our common stock during a specified time period may be subject to U.S. federal income tax and withholding on a sale, exchange or other disposition of such common stock, and may be required to file a U.S. federal income tax return.

Investor sentiment towards climate change, fossil fuels, sustainability, and other ESG matters could adversely affect our business and our stock price.

There have been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities, and other groups, to promote the divestment of shares of fossil fuel companies, as well as to pressure lenders and other financial services companies to limit or curtail activities with fossil fuel companies. As a result, some financial intermediaries, investors, and other capital markets participants reduced or ceased lending to, or investing in, companies that operate in industries with higher perceived environmental exposure, such as the oil and natural gas industry. If such divestment efforts are continued, the price of our common stock or debt securities, and our ability to access capital markets or to otherwise obtain new investment or financing, may be negatively impacted.

Members of the investment community also have expressed increased interest as to ESG practices and disclosures, including practices and disclosures related to greenhouse gases and climate change in the energy industry in particular, and diversity and inclusion initiatives and governance standards among companies more generally. The SEC, for example, promulgated new rules in 2024 that required disclosure of various specific risks related to climate but promptly issued an order staying their applicability pending resolution of legal challenges and later decided not to defend them in court. Such requirements may take effect in the future. A heightened emphasis on ESG may lead some members of the investment community to screen our ESG performance before investing in our common stock or debt securities or lending to us.

If we are unable to meet the ESG standards or investment or lending criteria set by these investors and funds, we may lose investors, investors may allocate a portion of their capital away from us, our cost of capital may increase, the price of our common stock may be negatively impacted, and our reputation may be negatively affected.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Cybersecurity risk management is part of the Company's overall enterprise risk management program. Our cybersecurity risk management program is designed to provide a framework for handling cybersecurity threats and incidents, including those associated with the use of third-party services and service providers. This framework includes steps for assessing a cybersecurity threat's severity and source, including whether the cybersecurity threat is associated with a third-party service provider, implementing cybersecurity countermeasures and threat mitigation strategies, and informing management and our Board of material cybersecurity threats and incidents. To prevent and detect material cybersecurity incidents, our framework further includes, among other things, ongoing security awareness training for employees, regular cybersecurity risk and vulnerability assessments, and mechanisms to detect and monitor unusual network activity. We recognize the complex and evolving nature of cybersecurity threats and engage with various third-party service providers, including cybersecurity assessors and consultants, to evaluate and test our cybersecurity risk management systems. This enables us to leverage knowledge and insights to align our cybersecurity strategies and processes with best practices for our industry and size. Additionally, we maintain industry-standard cybersecurity insurance to provide further protection against cybersecurity risk.

Our Board is ultimately responsible for overseeing our risk management, including cybersecurity risk management. Management is responsible for identifying, considering, and assessing material cybersecurity risks on an ongoing basis, establishing processes to ensure that such potential cybersecurity risk exposures are monitored, implementing appropriate mitigation measures, and maintaining cybersecurity programs. Our cybersecurity programs are under the direction of our Principal Financial Officer, who receives reports from our cybersecurity consultants and monitors the prevention, detection, mitigation, and remediation of cybersecurity incidents. Any significant cybersecurity incidents are reported to our independent Audit Committee and ultimately to our Board. There were no such cybersecurity incidents or threats that have materially impacted our business or operations. Management presents an assessment of our cybersecurity processes, procedures, and testing results to the Audit Committee at least annually.

Despite our efforts, we cannot eliminate all risks from cybersecurity threats nor provide assurances that we have not experienced an undetected cybersecurity incident. For more information about these risks, please see discussion captioned "Our business could be negatively affected by security threats. A cyber-attack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation, and/or financial loss." in Item 1A. *Risk Factors*.

Item 2. Properties

Information regarding our properties is included in Item 1. *Business* above and in Note 4, *"Property and Equipment"* to our consolidated financial statements in Item 8. *Consolidated Financial Statements and Supplementary Data*, which information is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 10, *"Commitments and Contingencies"* to our consolidated financial statements in Item 8. *Consolidated Financial Statements and Supplementary Data* for a description of any legal proceedings, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock is currently traded on the NYSE American stock exchange under the ticker symbol "EPM".

Shares Outstanding and Holders

As of June 30, 2025, there were 34,337,188 shares of common stock issued and outstanding. As of September 1, 2025, there were approximately 220 registered shareholders of our common stock.

Dividends

We began paying cash quarterly dividends on our common stock in December 2013. Over the last two fiscal years, we made the following cash dividends per share:

	Fiscal Year	
	2025	**2024**
Fourth fiscal quarter	$ 0.12	$ 0.12
Third fiscal quarter	0.12	0.12
Second fiscal quarter	0.12	0.12
First fiscal quarter	0.12	0.12

As of June 30, 2025, we have paid 47 consecutive quarterly dividends on our common stock. In September 2025, the Company declared a $0.12 per share dividend payable on September 30, 2025. Any future determination with regard to the payment of dividends will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, results of operations, applicable dividend restrictions, capital requirements, and other factors deemed relevant by the Board of Directors.

Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding Options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(1)
Equity compensation plans approved by security holders:			
Outstanding options	—	$ —	
Outstanding contingent rights to shares	241,613 (1)	—	
Total	241,613	—	2,462,908
Equity compensation plans not approved by security holders	—	—	—
Total	241,613	$ —	2,462,908

(1) The Evolution Petroleum Corporation Amended and Restated Equity Incentive Plan (the "Amended and Restated Plan") authorizes the issuance of 5.7 million shares of common stock. The duration of the Amended and Restated Plan is indefinite, provided that no new awards shall be made under the Amended and Restated Plan on or after December 5, 2034. As of June 30, 2025, we have granted 3.2 million equity awards under the 2016 Plan and 2.5 million shares of common stock remain available for future grants.

Issuer Purchases of Equity Securities

The table below summarizes information about the Company's purchases of its equity securities during the three months ended June 30, 2025.

Period	(a) Total number of shares purchased and received [(1)]	(b) Average price paid per share [(1)]	(c) Total number of shares purchased as part of public announced plans or programs[(2)]	(d) Maximum dollar value of shares that may yet be purchased under the plans or programs (in thousands)
April 2025	1,729	$ 4.33	—	$ —
May 2025	—	—	—	—
June 2025	36,652	4.70	—	—

(1) During the three months ended June 30, 2025, all of the shares received were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards.

Item 6. Reserved

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

Executive Overview

Liquidity and Capital Resources

Results of Operations

Critical Accounting Policies and Estimates

Executive Overview

General

Evolution Petroleum Corporation is an independent energy company focused on maximizing total returns to its shareholders through the ownership of and investment in onshore oil and natural gas properties in the United States. In support of that objective, our long-term goal is to maximize total shareholder return from a diversified portfolio of long-life oil and natural gas properties built through acquisitions and through selective development opportunities, production enhancements, and other exploitation efforts on our oil and natural gas properties.

Our oil and natural gas properties consist primarily of non-operated interests in the following areas (as well as small overriding royalty interests in four onshore central Texas wells):

- Our non-operated interest in TexMex consists of oil and natural gas producing properties where we hold an approximate 42% net working interest and 35% average net revenue interest located on approximately 27,800 gross (11,200 net) acres (all held by production) primarily in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas. The oil and natural gas properties are operated by Texian Operating Company.
- Our non-operated interests in the SCOOP and STACK plays, consist of oil and natural gas producing properties in the Anadarko basin, where we hold approximately 2.6% average net working interest and approximately 2.0% average net revenue interests located on approximately 103,700 gross (4,200 net) acres (approximately 97% held by production) across Blaine, Canadian, Carter, Custer, Dewey, Garvin, Grady, Kingfisher, McClain, Murray, and Stephens counties in Oklahoma. The oil and natural gas properties are operated by Continental Resources, Inc., Ovintiv USA Inc. and EOG Resources, Inc. with approximately 40% of wells operated by other operators.
- Our non-operated interests in the Chaveroo Field consist of a 50% net working interest, with an average associated 41% revenue interest, in approximately 4,500 gross (2,300 net) acres all held by production, associated with six development blocks, with the right to acquire the same working interest in additional development locations and associated acreage at a fixed price. The field is operated by PEDEVCO Corp. ("PEDEVCO").
- Our non-operated interests in the Jonah Field, a natural gas and NGL property in Sublette County, Wyoming, consist of approximately 20% average net working interest and approximately 15% average net revenue interest located on approximately 5,300 gross (950 net) acres all held by production. The properties are operated by Jonah Energy.
- Our non-operated interests in the Williston Basin, an oil and natural gas producing property, consist of approximately 39% average net working interest and approximately 33% average net revenue interest located on approximately 138,200 gross (41,300 net) acres (approximately 97% held by production) across Billings, Golden Valley, and McKenzie Counties in North Dakota. The properties are operated by Foundation Energy Management.
- Our non-operated interests in the Barnett Shale, a natural gas and NGL producing shale reservoir, consist of approximately 17% average net working interest and approximately 14% average net revenue interest (inclusive of small overriding royalty interests). The approximately 123,800 gross (21,000 net) acres are held by

production across nine North Texas counties. The oil and natural gas properties are primarily operated by Diversified Energy Company with approximately 10% of wells operated by six other operators.

- Our non-operated interests in the Hamilton Dome Field, a secondary recovery field utilizing water injection wells to pressurize the reservoir, consist of approximately 24% average net working interest, with an associated 20% average net revenue interest (inclusive of a small overriding royalty interest). The 5,900 gross acre unitized field, of which we hold approximately 1,400 net acres, is operated by Merit Energy Company, who owns the majority of the remaining working interest in the Hamilton Dome Field. The Hamilton Dome Field is located in the southwest region of the Big Horn Basin in northwest Wyoming.
- Our non-operated interests in the Delhi Field, a CO_2-EOR project, consist of approximately 24% average net working interest, with an associated 19% revenue interest and separate overriding royalty and mineral interests of approximately 7% yielding a total average net revenue interest of approximately 26%. The field is operated by Denbury Onshore LLC, a subsidiary of Exxon Mobil Corporation. The 13,600 gross acre unitized Delhi Field, of which we hold approximately 3,200 acres, is located in northeast Louisiana in Franklin, Madison, and Richland Parishes.

Recent Developments

Dividend Declaration

On September 11, 2025, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2025.

Purchase of SCOOP/STACK Minerals

On August 4, 2025, we completed the acquisition of certain mineral and royalty interests in the SCOOP/STACK area of Oklahoma from a non-affiliated private seller (the "Minerals Acquisition") in a cash transaction valued at approximately $17.0 million, subject to customary post-closing adjustments. The Minerals Acquisition has an effective date of May 1, 2025. We funded the purchase price for the Minerals Acquisition with a combination of $15.0 million in borrowings under our Senior Secured Credit Facility and cash on hand. The acquired assets include an average royalty interest of 0.6% located on approximately 5,500 net royalty acres located primarily in Grady and Canadian Counties, Oklahoma.

Senior Secured Credit Facility

On June 30, 2025, we entered into an amended and restated senior secured reserve-based credit agreement (the "Senior Secured Credit Facility") with MidFirst Bank, as administrative agent for the lenders party thereto, in an amount up to $200.0 million with an initial borrowing base of $65.0 million maturing on June 30, 2028. Refer to "*Liquidity and Capital Resources"* below for a further discussion.

Purchase of Non-operated Oil and Natural Gas Assets

On April 14, 2025, we closed the acquisition of non-operating working interests in certain long-life oil and natural gas wells located primarily in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas (the "TexMex Acquisition") from a private seller. The total purchase price for the TexMex Acquisition was approximately $9.0 million before customary post-closing adjustments, with an effective date of February 1, 2025. We funded the purchase price for the TexMex Acquisition with a combination of cash on hand and borrowings under our Senior Secured Credit Facility. The TexMex Acquisition includes an average working interest of 42% and an average revenue interest of 35% in approximately 600 wells.

At-the-Market ("ATM") Equity Sales Program

On October 21, 2024, we entered into an ATM equity Sales Agreement (the "ATM Sales Agreement") with Roth Capital Partners, LLC (the "Lead Agent"), Northland Securities Inc., and A.G.P./Alliance Global Partners pursuant to which we may issue and sell, from time to time, up to $30.0 million of shares of common stock through or to the Lead Agent, acting as agent or principal. For the year ended June 30, 2025, we sold a total of approximately 0.7 million shares of our common stock under the ATM Sales Agreement for net proceeds of approximately $3.5 million, after deducting $0.3 million in offering costs. We intend to use the net proceeds from any sales of common stock for general corporate purposes, including to repay outstanding indebtedness.

Proved Reserves

The following table is a summary of our proved reserves as of June 30, 2025 and 2024:

	Proved Reserves		
	2025	**2024**	**Change**
Proved Reserves MMBOE	27.1	31.8	(14.8)%
% Developed	83.7 %	75.6 %	8.1 %
Liquids %	62.2 %	59.1 %	3.1 %
Standardized Measure ($MM)	$ 155.2	$ 166.6	(6.8)%

Proved oil equivalent reserves as of June 30, 2025 were 27.1 MMBOE, a 4.7 MMBOE, or 14.8%, decrease from the previous year of 31.8 MMBOE. The net decrease in total proved reserves was primarily due to net negative revisions of 6.0 MMBOE and production roll-off of 2.6 MMBOE. These decreases were partially offset by 3.0 MMBOE of proved reserves purchased in the TexMex Acquisition as well as extensions of 0.9 MMBOE primarily at Chaveroo Field and SCOOP/STACK. Approximately 1.6 MMBOE of downward revisions were in our oil reserves and 4.4 MMBOE of downward revisions were in our natural gas and NGL reserves. Proved oil reserves declined primarily due to a decrease in the SEC trailing 12-month oil price of 10.4% from the prior fiscal year and drop-off of Williston Basin PUDs due to timing of future drilling plans. Natural gas and natural gas liquids reserves decreased due to a combination of lower price differentials received, specifically at Jonah Field, an increase in lease operating costs at our Barnett Shale properties, and drop-off of the Williston Basin PUDs due to timing of future drilling plans. These metrics impacted the late-in-life economic limits for oil, natural gas, and NGL production.

The Standardized Measure for proved reserves decreased 6.8% to $155.2 million, primarily due to volumes produced and sold and our overall downward revisions in proved reserves as discussed above. Oil prices decreased 10.4% from the prior year when oil was $79.45 per barrel compared to $71.20 per barrel at June 30, 2025. While the SEC price for natural gas increased 23.7% from $2.32 per MMBtu of natural gas at June 30, 2024 to $2.87 per MMBtu of natural gas at June 30, 2025, certain changes in other metrics such as lower price differentials caused our natural gas and natural gas liquids reserves to decrease, as stated above. Our proved reserves consist of 45% oil, 38% natural gas, and 17% NGLs; 83.7% are classified as proved developed and 16.3% are proved undeveloped.

Additional property and project information is included under Item 1. *Business* and in Note 4, *"Property and Equipment"* and our *Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data*, and in Exhibit 99.1 and 99.2 of this Form 10-K.

Risks and uncertainties

The oil and natural gas industry is a global market impacted by many factors, such as government regulations, particularly in the areas of tariffs, trade sanctions, taxation, energy, climate change and the environment, geopolitical instability and armed conflicts (including between Russia and Ukraine and in the Middle East between Israel and Gaza), demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

Oil, natural gas, and NGL prices have been, and we expect may continue to be, volatile. Lower oil and natural gas prices not only decrease our revenues, but an extended decline in oil or natural gas prices may affect planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our Senior Secured Credit Facility, which is determined at the discretion of the lenders based on various factors including the collateral value of our proved reserves.

At times, we do maintain cash balances in excess of the U.S. Federal Deposit Insurance Corporation ("FDIC"); however, we believe our bank counterparty to be financially sound. We also utilize insured cash sweep deposits to maximize the amount of our cash that is protected by FDIC insurance. We also rely heavily on our third-party operators who manage their own liquidity with various financial institutions. In recent years, the Federal Reserve took actions to raise interest rates in an attempt to tame inflation and slow the economy, which has contributed to volatility in markets. Currently, our oil and natural gas properties are operated by third-party operators and involve other third-party working interest owners. As a result, we have limited ability to influence the operation or future development of such properties. Despite these uncertainties, we remain focused on our long-term objectives and continue to be proactive with our third-party operators to review the management of capital expenditures.

Given the dynamic nature of these factors and events, we cannot reasonably estimate the period of time that certain market conditions will persist. Continuing volatility in political, trade, regulatory and economic conditions could impact supply and demand fundamentals, and any related significant declines in crude oil, natural gas, and NGL prices could lead to proved property impairments in the future. Future impairments of proved properties are difficult to predict, especially in a volatile price environment.

Liquidity and Capital Resources

As of June 30, 2025, we had $2.5 million in cash and cash equivalents and $37.5 million outstanding borrowings on our Senior Secured Credit Facility compared to $6.4 million in cash and cash equivalents and $39.5 million outstanding borrowings on our Senior Secured Credit Facility at June 30, 2024. Our primary sources of liquidity and capital resources during the year ended June 30, 2025 were cash provided by operations and net proceeds from the ATM Sales agreement. Our primary uses of liquidity and capital resources for the year ended June 30, 2025 were cash dividend payments to our common stockholders, our TexMex Acquisition, net repayments of borrowings under our Senior Secured Credit Facility and development capital expenditures, primarily at Chaveroo Field and SCOOP/STACK. As of June 30, 2025, working capital was a deficit of $4.0 million. As of June 30, 2024, working capital was $5.9 million.

As noted above, on June 30, 2025, we entered into a syndicated amended and restated senior secured reserve-based credit agreement (the "Senior Secured Credit Facility") with MidFirst Bank, as administrative agent for the lenders party thereto. The Senior Secured Credit Facility has a maximum capacity of $200.0 million subject to a borrowing base determined by the lenders based on the value of our oil and natural gas properties. The Senior Secured Credit Facility has a current borrowing base of $65.0 million. As of June 30, 2025, we had $37.5 million of indebtedness outstanding and availability of $27.5 million. The Senior Secured Credit Facility is secured by substantially all of our oil and natural gas properties and matures on June 30, 2028.

Borrowings bear interest, at our option, at either (i) the SOFR, subject to a minimum SOFR of 3.25%, plus a credit spread adjustment of 0.05%, or (ii) the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.0%, plus, in either case of (i) or (ii), an applicable margin of 2.75%. For the years ended June 30, 2025 and 2024, the weighted average interest on our borrowings were 7.48% and 8.12%, respectively. The Senior Secured Credit Facility contains covenants requiring the maintenance of (i) a total leverage ratio of not more than 3.00 to 1.00, (ii) a current ratio of not less than 1.00 to 1.00, and (iii) a consolidated tangible net worth of not less than $40.0 million, each as defined in the Senior Secured Credit Facility. In addition, the Senior Secured Credit Facility contains hedging requirements that apply when utilization is greater than 25% of (x) the Margined Collateral Value, as defined under the Senior Secured Credit Facility, at any time when the leverage ratio is less than 2.25 to 1.00, or (y) the borrowing base, at any time when the leverage ratio is greater than or equal to 2.25 to 1.00. It also contains other customary affirmative and negative covenants, and events of default. As of June 30, 2025, we were in compliance with all covenants under the Senior Secured Credit Facility.

The Senior Secured Credit Facility requires for redeterminations of the borrowing base to occur semi-annually. At each redetermination, the Margined Collateral Value is updated based on the estimated value of our oil and natural gas properties, which includes our proved developed reserves, proved undeveloped reserves, and other relevant factors consistent with customary oil and natural gas lending criteria. On August 29, 2025, we entered into an amendment to our Senior Secured Credit Facility with MidFirst Bank, whereas it was determined for purposes of the hedge covenant that total crude oil and natural gas volumes from proved developed producing reserves will be combined on a barrels of oil equivalent ("BOE") basis to determine compliance with the hedging covenant.

We have historically funded operations through cash from operations and working capital. Our primary source of cash is the sale of produced crude oil, natural gas, and NGLs. A portion of these cash flows is used to fund capital expenditures and pay cash dividends to shareholders. We expect to fund near-future capital development activities for our properties with cash flows from operating activities, and, as needed, borrowings under our Senior Secured Credit Facility and proceeds from the ATM Sales Agreement (as described in "*Recent Developments*" above).

We are pursuing new growth opportunities through acquisitions and other transactions. In addition to cash on hand, we have access to the undrawn portion of the borrowing base available under our Senior Secured Credit Facility, totaling \$27.5 million as of June 30, 2025. As stated above in *"Recent Developments,"* on August 4, 2025, we purchased mineral and royalty interests in the SCOOP/STACK area of Oklahoma for approximately \$17.0 million. We funded the acquisition with borrowings of \$15.0 million on our Senior Secured Credit Facility and cash on hand. On August 5, 2025, we issued an \$0.8 million letter of credit agreement to Enterprise Products Operating, LLC, in connection with our gathering and processing agreements at Jonah Field, in exchange for the return of our cash collateral that had been previously provided. This additional borrowing and letter of credit reduced our remaining availability to \$11.7 million subsequent to our fiscal year end. We also have an effective shelf registration statement with the SEC under which we may issue up to \$500.0 million of new debt or equity securities.

On October 21, 2024, we entered into an ATM Sales Agreement with Roth Capital Partners, LLC as our Lead Agent, Northland Securities Inc., and A.G.P./Alliance Global Partners pursuant to which we may issue and sell, from time to time, up to \$30.0 million of shares of common stock through or to the Lead Agent, acting as agent or principal. For the year ended June 30, 2025, we sold a total of approximately 0.7 million shares of our common stock under the ATM Sales Agreement for net proceeds of approximately \$3.5 million, after deducting \$0.3 million in offering costs.

Our Board of Directors instituted a cash dividend on common stock in December 2013. We have since paid 47 consecutive quarterly dividends. Distribution of a substantial portion of free cash flow in excess of operating and capital requirements through cash dividends remains a priority of our financial strategy, and it is our long-term goal to increase dividends over time, as appropriate. On September 11, 2025, the Board of Directors declared a quarterly cash dividend of \$0.12 per share of common stock to shareholders of record on September 22, 2025 and payable on September 30, 2025.

On September 8, 2022, our Board of Directors approved a share repurchase program, under which we were authorized to repurchase up to \$25.0 million of our common stock in the open market through December 31, 2024. As we continue to focus on our goal of maximizing total shareholder return, the Board of Directors along with the management team believe that a share repurchase program may be complimentary to the existing dividend policy and could be a tax efficient means to further improve shareholder return. In fiscal year 2025, we did not repurchase any shares under the program. In fiscal year 2024, we entered into a Rule 10b5-1 plan that authorized a broker to repurchase shares in the open market subject to pre-defined limitations on trading volume and price. The plan was effective until June 30, 2024 and had a maximum authorized amount of \$0.8 million over that period. During the fiscal year ended June 30, 2024, approximately 0.1 million shares of the Company's common stock were repurchased under the plan at a cost of approximately \$0.8 million, including incremental direct transaction costs. We funded repurchases from working capital and cash provided by operating activities. These shares were subsequently cancelled. We may enter into additional share repurchase programs in the future as well as Rule 10b5-1 plans, the terms of which will be approved by the Board of Directors.

Capital Expenditures

For the year ended June 30, 2025, we incurred $13.2 million on development capital expenditures. A majority of our spending occurred at the Chaveroo Field where we participated in drilling and completion of four gross wells, and at SCOOP/STACK where our operators have brought 13 gross (0.14 net) wells online during the fiscal year.

Based on discussions with our operators, we expect capital workover projects to continue in most of our fields. Overall, for fiscal year 2026, we expect budgeted capital expenditures to be in the range of $4.0 million to $6.0 million, which excludes any potential acquisitions. Our expected capital expenditures for the next 12 months include bringing approximately five gross wells online at our SCOOP/STACK properties. Additionally, as our third-party operators continue to be active around our acreage, we would expect additional wells to be drilled and/or completed. At Chaveroo Field, we expect to have drilling permits in hand for the next round of six wells before the end of the fiscal third quarter 2026 and the final decision by us and our partner as to timing for spudding these wells will be made based on oil prices and completed well costs at that time.

As of June 30, 2025, our PUD reserves included 4.4 MMBOE of reserves and approximately $75.1 million of future development costs primarily associated with the Chaveroo Field, Williston Basin, and SCOOP/STACK properties.

Funding for our anticipated capital expenditures over the near-term is expected to be met from cash flows from operations and as needed from borrowings under our Senior Secured Credit Facility.

Full Cost Pool Ceiling Test

Under the full cost method of accounting, capitalized costs of oil and natural gas properties, net of accumulated depletion, depreciation, and amortization and related deferred taxes, are limited to the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the valuation "ceiling"). If capitalized costs exceed the full cost ceiling, the excess would be charged to expense as a write-down of oil and natural gas properties in the quarter in which the excess occurred. The quarterly ceiling test calculation requires that we use the average first day of the month price for our petroleum products during the 12-month period ending with the balance sheet date. The prices used in calculating our ceiling test as of June 30, 2025 were $71.20 per barrel of oil, $2.87 per MMBtu of natural gas and $25.24 per barrel of NGLs. As of June 30, 2025, our capitalized costs of oil and natural gas properties were below the full cost valuation ceiling. If commodity price levels were to substantially decline from the 12-month average first day of the month pricing levels as of June 30, 2025 and remain down for a prolonged period of time, our valuation ceiling over our capitalized costs may be reduced and adversely impact our ceiling tests in future quarters. We cannot give assurance that a write-down of capitalized oil and natural gas properties will not be required in the future. Additionally, a 10% reduction in respective commodity prices at June 30, 2025, while all other factors remained constant, would not have generated an impairment.

Overview of Cash Flow Activities

	Years Ended June 30,		
	2025	**2024**	**Change**
Cash flows provided by operating activities	$ 33,052	$ 22,729	$ 10,323
Cash flows used in investing activities	(21,642)	(49,633)	27,991
Cash flows provided by (used in) financing activities	(15,349)	22,316	(37,665)
Net decrease in cash and cash equivalents	$ (3,939)	$ (4,588)	$ 649

Cash provided by operating activities increased $10.3 million during the fiscal year ended June 30, 2025 compared to fiscal year ended June 30, 2024 primarily due to changes in the timing of our working capital. Cash flows provided by operating activities before changes in working capital for the year ended June 30, 2025 decreased $1.8 million compared to the year ended June 30, 2024, primarily due to increases in our lease operating costs and interest expenses in the current year partially offset by realized gains on derivative contracts in the current year of $1.0 million compared to realized losses on derivative contracts in the prior year of $0.4 million. Refer to "*Results of Operations*" below for further information.

Cash used in investing activities for the year ended June 30, 2025 decreased $28.0 million from the prior year primarily due to the acquisition of our SCOOP/STACK properties in February 2024. In the prior year, net cash spent on acquisitions was $38.7 million, whereas in the current year, net cash spent on acquisitions was $9.0 million. In addition, in fiscal year 2025, we spent $12.6 million on development capital expenditures as compared to $10.9 million in the prior year. In the current fiscal year capital expenditures included drilling and completing four gross (2.0 net) Chaveroo wells and thirteen gross (0.14 net) SCOOP/STACK wells. In the prior year, the Company participated in drilling and completing three gross (1.5 net) Chaveroo wells and to a lesser extent, drilling and completion expenditures at Delhi Field and SCOOP/STACK.

Net cash flows used in financing activities for the year ended June 30, 2025 were $15.3 million compared to net cash flows provided by financing activities of $22.3 million for the year ended June 30, 2024. In the current year period, we paid $16.3 million in cash dividends to our common stockholders, repaid $2.0 million of net borrowings under our Senior Secured Credit Facility, and received net proceeds from the sale of common stock under the ATM Sales Agreement of approximately $3.5 million, after deducting $0.3 million in offering costs. In the prior year period, we received net borrowings of $39.5 million under our Senior Secured Credit Facility to finance our SCOOP/STACK Acquisitions, paid $16.0 million in cash dividends to our common stockholders together with $0.8 million paid to repurchase shares of common stock under our share repurchase plan.

Results of Operations
Years Ended June 30, 2025 and 2024

We reported a net income of $1.5 million and $4.1 million for the years ended June 30, 2025 and 2024, respectively. The following table summarizes the comparison of financial information for the periods presented:

	Years Ended June 30,			
(in thousands, except per unit and per BOE amounts)	**2025**	**2024**	**Variance**	**Variance %**
Net income (loss)	$ 1,473	$ 4,080	$ (2,607)	(63.9) %
Revenues:				
Crude oil	51,102	53,446	(2,344)	(4.4) %
Natural gas	23,516	21,525	1,991	9.2 %
Natural gas liquids	11,222	10,906	316	2.9 %
Total revenues	85,840	85,877	(37)	(0.0) %
Operating costs:				
Lease operating costs:				
Ad valorem and production taxes	5,709	5,285	424	8.0 %
Gathering, transportation, and other costs	11,357	9,656	1,701	17.6 %
Other lease operating costs	32,272	33,332	(1,060)	(3.2) %
Depletion, depreciation, and accretion:				
Depletion of full cost proved oil and natural gas properties	20,374	18,605	1,769	9.5 %
Accretion of asset retirement obligations	1,619	1,457	162	11.1 %
General and administrative expenses:				
General and administrative	7,852	7,499	353	4.7 %
Stock-based compensation	2,482	2,137	345	16.1 %
Other income (expense):				
Net gain (loss) on derivative contracts	473	(1,292)	1,765	(136.6) %
Interest and other income	191	342	(151)	(44.2) %
Interest expense	(2,970)	(1,459)	(1,511)	103.6 %
Income tax (expense) benefit	(396)	(1,417)	1,021	(72.1) %
Production:				
Crude oil (MBBL)	766	709	57	8.0 %
Natural gas (MMCF)	8,409	8,243	166	2.0 %
Natural gas liquids (MBBL)	414	402	12	3.0 %
Equivalent (MBOE)[(1)]	2,582	2,485	97	3.9 %
Average daily production (BOEPD)[(1)]	7,074	6,790	284	4.2 %
Average price per unit[(2)]:				
Crude oil (BBL)	$ 66.71	$ 75.38	$ (8.67)	(11.5) %
Natural gas (MCF)	2.80	2.61	0.19	7.3 %
Natural Gas Liquids (BBL)	27.11	27.13	(0.02)	(0.1) %
Equivalent (BOE)[(1)]	33.25	34.56	(1.31)	(3.8) %
Average cost per unit:				
Operating costs:				
Lease operating costs:				
Ad valorem and production taxes	$ 2.21	$ 2.13	$ 0.08	3.8 %
Gathering, transportation, and other costs	4.40	3.89	0.51	13.1 %
Other lease operating costs	12.50	13.41	(0.91)	(6.8) %
Depletion of full cost proved oil and natural gas properties	7.89	7.49	0.40	5.3 %
General and administrative expenses:				
General and administrative	3.04	3.02	0.02	0.7 %
Stock-based compensation	0.96	0.86	0.10	11.6 %

(1) Equivalent oil reserves are defined as six MCF of natural gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Natural gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

(2) Amounts exclude the impact of cash paid or received on the settlement of derivative contracts since we did not elect to apply hedge accounting.

Revenues

Crude oil, natural gas and NGL revenues were $85.8 million and $85.9 million for the fiscal years ended June 30, 2025 and 2024, respectively. The decrease in revenues is primarily due to the decrease in our average realized price per BOE partially offset by an increase in our sales volumes primarily as a result of our recent acquisitions. Our average realized commodity price (excluding the impact of derivative contracts) decreased approximately $1.31 per BOE, or 3.8%, for the fiscal year ended June 30, 2025 compared to June 30, 2024. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, inventory storage levels, basis differentials and other factors. While crude oil and NGL prices decreased 11.5% and 0.1% from the prior fiscal year respectively, our average realized commodity prices, realized natural gas prices increased 7.3% from the prior fiscal year predominately due to favorable pricing recognized from our SCOOP/STACK properties. Average daily equivalent production increased 4.2% from 6,790 BOEPD to 7,074 BOEPD in the current fiscal year as a result of additional production from newly drilled wells at Chaveroo Field, the Tex Mex Acquisition in April 2025, and drilling activities that are ongoing at SCOOP/STACK since the prior year end. The increase in production was partially offset by natural production declines in our other fields.

Lease Operating Costs

Ad valorem and production taxes were $5.7 million and $5.3 million for the years ended June 30, 2025 and 2024, respectively. The increase in ad valorem and production taxes is primarily due to our SCOOP/STACK Acquisitions since the prior year period. On a per unit basis, ad valorem and production taxes were $2.21 per BOE and $2.13 per BOE for the years ended June 30, 2025 and 2024, respectively.

Gathering, transportation and other costs were $11.4 million for the year ended June 30, 2025 compared to $9.7 million for the year ended June 30, 2024. These costs are gathering, transportation and processing fees we incur primarily for our natural gas producing properties. The increase is primarily due to the SCOOP/STACK Acquisitions in February 2024 which increased gathering, transportation and other costs by $1.2 million over the prior year period. On a per unit basis, gathering, transportation and other costs were $4.40 per BOE and $3.89 per BOE for the years ended June 30, 2025 and 2024, respectively.

Other lease operating costs decreased $1.1 million, or 3.2%, compared to the prior fiscal year primarily due to a $1.9 million credit from the operator of one of our Barnett Shale properties due to a joint venture audit combined with the cessation of CO_2 purchases at Delhi late in the third fiscal quarter. CO_2 purchases resumed in late October of 2024 following the pipeline shutdown for maintenance and repairs early in 2024. Consequently, we had net purchases of $2.6 million of CO_2 for the year ended June 30, 2025 compared to net purchases of $4.2 million in the prior year period. Partially offsetting the reduction in CO_2 purchases were cost increases due to our acquisitions of TexMex in April 2025 and SCOOP/STACK in February 2024, which collectively increased other lease operating costs by $2.3 million over the prior year period. On a per unit basis, other lease operating costs decreased to $12.50 per BOE in the current year from $13.41 per BOE in the prior year, primarily due to an overall increase in production.

Depletion of Full Cost Proved Oil and Natural Gas Properties

Depletion expense increased $1.8 million or 9.5% from $18.6 million for the fiscal year ended June 30, 2024 to $20.4 million for the fiscal year ended June 30, 2025 primarily due to an increase in the depletion rate. On a per unit basis, depletion expense was $7.89 per BOE and $7.49 per BOE for the fiscal years ended June 30, 2025 and 2024, respectively. The depletion rate of our unit of production calculation increased primarily due to an overall decrease in our reserves estimates since the prior year period.

General and Administrative Expenses

General and administrative expenses for the fiscal year ended June 30, 2025 increased $0.4 million, or 4.7%, to $7.9 million compared to $7.5 million for the fiscal year ended June 30, 2024. The increase primarily relates higher salary and compensation expense adjustments for existing employees. On a per unit basis, general and administrative expenses were $3.04 per BOE and $3.02 per BOE for the years ended June 30, 2025 and 2024, respectively.

Stock-based Compensation Expenses

Stock-based compensation increased $0.3 million to $2.5 million for the year ended June 30, 2025 compared to $2.1 million the prior period. The increase is due to new awards granted during the current year.

Net Gain (Loss) on Derivative Contracts

We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in oil and natural gas prices. Financial hedges are a requirement under our Senior Secured Credit Facility and help establish commodity price floors, contributing to stable cash flows when derivative contracts are settled. We have elected not to designate our open derivative contracts for hedge accounting, and accordingly, we recorded the net change in the mark-to-market valuation of the derivative contracts in the consolidated statements of operations. The amounts recorded on the consolidated statements of operations related to derivative contracts represent the (i) gains (losses) related to fair value adjustments on our open, or unrealized, derivative contracts, and (ii) gains (losses) on settlements of derivative contracts for positions that have settled or been realized. The table below summarizes our net realized and unrealized gains (losses) on derivative contracts as well as the impact of net realized (gains) losses on our average realized prices for the periods presented. As a result of our SCOOP/STACK Acquisitions in February 2024 and the corresponding borrowings on our Senior Secured Credit Facility, we were required by terms in our Senior Secured Credit Facility to hedge a portion of our production. The increase in the forward curve for future natural gas prices, as of June 30, 2025 as compared to June 30, 2024, resulted in a net unrealized loss on the mark-to-market of our hedges for the year ended June 30, 2025. As of June 30, 2025, we had a $2.0 million derivative asset, $1.8 million of which was classified as current, and a $3.4 million derivative liability, $1.6 million of which was classified as current.

	Years Ended June 30,			
(in thousands, except per unit and per BOE amounts)	**2025**	**2024**	**Variance**	**Variance %**
Realized gain (loss) on derivative contracts	$ 965	$ (399)	$ 1,364	(341.9) %
Unrealized gain (loss) on derivative contracts	(492)	(893)	401	(44.9) %
Total net gain (loss) on derivative contracts	$ 473	$ (1,292)	$ 1,765	(136.6) %
Average realized crude oil price per BBL	$ 66.71	$ 75.38	$ (8.67)	(11.5) %
Cash effect of oil derivative contracts per BBL	0.84	(0.56)	1.40	(250.0) %
Crude oil price per Bbl (including impact of realized derivatives)	$ 67.55	$ 74.82	$ (7.27)	(9.7) %
Average realized natural gas price per MCF	$ 2.80	$ 2.61	$ 0.19	7.3 %
Cash effect of natural gas derivative contracts per MCF	0.04	—	0.04	— %
Natural gas price per Mcf (including impact of realized derivatives)	$ 2.84	$ 2.61	$ 0.23	8.8 %

Interest Expense

Interest expense increased $1.5 million during the fiscal year ended June 30, 2025 compared to fiscal year 2024 primarily due to borrowings drawn on our Senior Secured Credit Facility to finance our SCOOP/STACK Acquisitions in February 2024. Partially offsetting the increase in interest expense is the decrease in our weighted average interest rate on our borrowings to 7.48% for the fiscal year ended June 30, 2025 compared to 8.12% for fiscal year 2024.

Income tax (expense) provision

For the year ended June 30, 2025, we recognized income tax expense of $0.4 million on income before income taxes of $1.9 million compared to an income tax expense of $1.4 million on income before income taxes of $5.5 million for the year ended June 30, 2024. The effective tax rates were 21.2% and 25.8% for the years ended June 30, 2025 and 2024, respectively. The decrease in the effective tax rate from the prior year period is due to federal tax credits on marginal natural gas wells for the calendar year 2024 and 2025.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires that we select certain accounting policies and make estimates and assumptions that affect the reported amounts of the assets, liabilities, and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. These policies, together with our estimates, have a significant effect on our consolidated financial statements. Our significant accounting policies are included in Note 1, *"Summary of Significant Events and Accounting Policies"* to our consolidated statements in Item 8. Following is a discussion of our most critical accounting estimates, judgments, and uncertainties that are inherent in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and natural gas industry. We apply the full cost accounting method for our oil and natural gas properties as prescribed by SEC Regulation S-X Rule 4-10. Under this method of accounting, the costs of unsuccessful and successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration, and development activities but does not include any costs related to production, general corporate overhead, or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties. We exclude these costs until the property has been evaluated. Costs are transferred to the full cost pool as the properties are evaluated. As of June 30, 2025 and 2024, we had no unevaluated property costs. Oil and natural gas properties include costs that are excluded from depletion and amortization, which represent investments in unproved and unevaluated properties and include non-producing leasehold, geologic and geophysical costs associated with leasehold or drilling interests, and exploration drilling costs.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense and the estimated future net cash flows associated with those proved reserves is the basis for determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex and requires significant decisions in the evaluation of all available geologic, geophysical, engineering, and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information; this includes reservoir performance, additional development activity, new geologic and geophysical data, additional drilling, technological advancements, price changes, and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates prepared by our third-party independent engineers represent the most accurate assessments possible, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and/or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves. These changes could affect our quarterly ceiling test calculation and could significantly affect our depletion rate. Additionally, a 10% decrease in commodity prices used to determine our proved reserves as of June 30, 2025, while all other factors remained constant, would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in our proved reserve estimates at June 30, 2025 of 10% would affect depletion, depreciation, and amortization expense by approximately $0.6 million.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and natural gas reserves. The rule allows consideration of new technologies in evaluating reserves, generally limits the designation of proved reserves to those projects forecasted to be drilled five years from the initial recognition date of such reserves, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and natural gas reserves using an average price based on the previous 12-month unweighted arithmetic average first-day-of-the-month price rather than year-end prices, revises the disclosure requirements for oil and natural gas operations, and revises accounting for the limitation on capitalized costs for full cost companies.

Stock-based Compensation. The fair value, and for certain awards the expected vesting period, of our performance-based awards were determined using a Monte Carlo simulation. This technique uses a geometric Brownian motion model with defined variables and randomly generates values for each variable through multiple trials. Variables include stock price volatility, expected term of the award, the expected risk-free interest rate, and the expected dividend yield of our stock. The risk-free interest rate used is the U.S. Treasury yield for bonds matching the expected term of the award on the date of grant. Vesting of performance-based awards is based on our total common stock return compared to a peer group of other companies in our industry with comparable market capitalizations and, for certain awards, our share price attaining a set target.

Recent Accounting Pronouncements. Refer to Note 1, *"Summary of Significant Events and Accounting Policies"* to our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* for discussion of the recent accounting pronouncements issued by the Financial Accounting Standards Board.

Item 7A. Quantitative and Qualitative Disclosures About Market Risks

Derivative Instruments and Hedging Activity

We are exposed to various risks, including energy commodity price risk, such as price differentials between the NYMEX commodity price and the index price at the location where our production is sold. When oil, natural gas, and NGL prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we monitor commodity prices to identify the potential need for the use of derivative financial instruments to provide partial protection against declines in oil and natural gas prices. We do not enter into derivative contracts for speculative trading purposes. In accordance with our Senior Secured Credit Facility, we may be required to enter into hedges if we meet certain utilization levels of the borrowing base under the credit facility. We intend to remain in compliance with these covenants and will enter into derivative contracts from time to time to meet the requirements. Additionally, depending on market conditions, financial and other considerations we may enter into additional hedges to meet our objectives of increasing value to shareholders. We may also, from time to time, restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competitive market makers. For the derivative contracts settled during fiscal 2025 and 2024, we did not post collateral. We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, ("ASC 815"). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 7, *"Derivatives"* to our consolidated financial statements for more details.

Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents. Additionally, any borrowings under the Senior Secured Credit Facility will bear interest, at our option, at either (i) SOFR, subject to a minimum SOFR of 3.25%, plus a credit spread adjustment of 0.05%, or (ii) the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%, plus, in either case of (i) or (ii), an applicable margin of 2.75%. SOFR rates are sensitive to the period of contract and market volatility, as well as changes in forward interest rate yields. Under our current practices, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Item 8. Consolidated Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Evolution Petroleum Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries (the “Company”) as of June 30, 2025 and 2024, the related consolidated statements of operations, cash flows, and changes in stockholders’ equity for the years then ended, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of June 30, 2025 and 2024, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

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

The Impact of Proved Oil and Natural Gas Reserves on Depletion, Depreciation, and Amortization (“DD&A”) and Full Cost Ceiling Test Impairment Calculation (“Ceiling Test”)

As described in Note 1, the Company follows the full cost method of accounting, pursuant to which oil and natural gas properties are amortized using the unit-of-production method over total proved reserves. The Company’s proved oil and natural gas properties are evaluated for impairment by the Ceiling Test utilizing the Company’s proved oil and natural gas reserves in accordance with accounting principles generally accepted in the United States of America and SEC guidelines. For the year ended June 30, 2025, the Company recorded DD&A related to its proved oil and natural gas properties of approximately $20.4 million, and there was no ceiling test impairment.

The Company engages two independent reservoir engineering firms to serve as a management specialist and to assist with the estimation of proved oil and natural gas reserves. To estimate the volume of proved oil and natural gas reserves and associated future net cash flows, management and their specialists make significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties ("PUDs"). The estimation of proved oil and natural gas reserves is impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required. Changes in significant assumptions or engineering data could have a significant impact on the amount of DD&A and impairment recorded for the Company's proved oil and natural gas properties.

We identified the impact of proved oil and natural gas reserves on DD&A and the Ceiling Test as a critical audit matter due to use of significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the significant assumptions used in developing those estimates of proved oil and natural gas reserves.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the knowledge, skill, and ability of the Company's third-party reservoir engineering specialists and their relationship to the Company, inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the proved reserve volumes and reading the reserve report prepared by the reservoir engineering specialists.
- Evaluating significant assumptions used by management and its specialists in developing the estimates of proved oil and natural gas reserves, including pricing differentials, future operations costs, future production rates, and capital expenditures. The procedures performed included tests of the data inputs used by specialists for completeness and accuracy and an evaluation of the specialist's findings. The procedures performed included:
    - Testing the data inputs used by specialists for completeness and accuracy;
    - Testing the specialists' findings for mathematical accuracy; and
    - Performing analytical procedures on pricing, reserve quantities and cost estimates developed by management and its specialists. Those procedures entailed comparisons of:
        - prices to historical benchmark prices, adjusted for pricing differentials,
        - production forecasts to recent historical actual production,
        - projections of lease operating costs to costs incurred by property during fiscal year ended June 30, 2025,
        - projected production taxes to recent historical taxes incurred and to statutory tax rates, and
        - assessed the reasonableness of forecasted capital expenditures by comparing to recent drilling costs or approval for expenditures.
- Evaluating the accuracy of revenue and working interest percentages used in the reserve reports by comparing a sample of such interests to the land records.
- Performing retrospective review of historical estimates of proved oil and natural gas reserves to identify potential management bias in estimates.
- Testing the mathematical accuracy of the Company's depletion and impairment calculations that included these proved reserves.

/s/ Baker Tilly US, LLP

Houston, Texas
September 17, 2025

We have served as the Company's auditor since 2017.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	June 30, 2025	June 30, 2024
Assets		
Current assets		
Cash and cash equivalents	$ 2,507	$ 6,446
Receivables from crude oil, natural gas, and natural gas liquids revenues	10,804	10,826
Derivative contract assets	1,777	596
Prepaid expenses and other current assets	2,287	3,855
Total current assets	17,375	21,723
Property and equipment, net of depletion, depreciation, and impairment		
Oil and natural gas properties, net—full-cost method of accounting, of which none were excluded from amortization	142,248	139,685
Other noncurrent assets		
Derivative contract assets	198	171
Other assets	431	1,298
Total assets	$ 160,252	$ 162,877
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 12,901	$ 8,308
Accrued liabilities and other	6,909	6,239
Derivative contract liabilities	1,577	1,192
State and federal taxes payable	—	74
Total current liabilities	21,387	15,813
Long term liabilities		
Senior secured credit facility	37,500	39,500
Deferred income taxes	6,234	6,702
Asset retirement obligations	21,535	19,209
Derivative contract liabilities	1,783	468
Operating lease liability	—	58
Total liabilities	88,439	81,750
Commitments and contingencies (Note 10)		
Stockholders' equity		
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 34,337,188 and 33,339,535 shares as of June 30, 2025 and 2024, respectively	34	33
Additional paid-in capital	46,650	41,091
Retained earnings	25,129	40,003
Total stockholders' equity	71,813	81,127
Total liabilities and stockholders' equity	$ 160,252	$ 162,877

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended June 30, 2025	Years Ended June 30, 2024
Revenues		
Crude oil	$ 51,102	$ 53,446
Natural gas	23,516	21,525
Natural gas liquids	11,222	10,906
Total revenues	85,840	85,877
Operating costs		
Lease operating costs	49,338	48,273
Depletion, depreciation, and accretion	21,993	20,062
General and administrative expenses	10,334	9,636
Total operating costs	81,665	77,971
Income (loss) from operations	4,175	7,906
Other income (expense)		
Net gain (loss) on derivative contracts	473	(1,292)
Interest and other income	191	342
Interest expense	(2,970)	(1,459)
Income (loss) before income taxes	1,869	5,497
Income tax (expense) benefit	(396)	(1,417)
Net income (loss)	$ 1,473	$ 4,080
Net income (loss) per common share:		
Basic	$ 0.03	$ 0.12
Diluted	$ 0.03	$ 0.12
Weighted average number of common shares outstanding:		
Basic	33,158	32,691
Diluted	33,323	32,901

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended June 30,	
	2025	**2024**
Cash flows from operating activities:		
Net income (loss)	$ 1,473	$ 4,080
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, and accretion	21,993	20,062
Stock-based compensation	2,482	2,137
Settlement of asset retirement obligations	(385)	(20)
Deferred income taxes	(468)	(101)
Unrealized (gain) loss on derivative contracts	492	893
Accrued settlements on derivative contracts	(251)	67
Other	(8)	—
Changes in operating assets and liabilities:		
Receivables from crude oil, natural gas, and natural gas liquids revenues	75	(2,910)
Prepaid expenses and other current assets	2,925	(1,562)
Accounts payable and accrued liabilities and other	4,798	374
State and federal taxes payable	(74)	(291)
Net cash provided by operating activities	33,052	22,729
Cash flows from investing activities:		
Acquisition of oil and natural gas properties	(9,019)	(38,734)
Capital expenditures for oil and natural gas properties	(12,623)	(10,899)
Net cash used in investing activities	(21,642)	(49,633)
Cash flows from financing activities:		
Common stock dividends paid	(16,347)	(16,040)
Common stock repurchases, including stock surrendered for tax withholding	(442)	(1,144)
Borrowings under senior secured credit facility	2,000	42,500
Repayments of senior secured credit facility	(4,000)	(3,000)
Debt issuance costs	(90)	—
Issuance of common stock	3,840	—
Offering costs	(310)	—
Net cash provided by (used in) financing activities	(15,349)	22,316
Net increase (decrease) in cash and cash equivalents	(3,939)	(4,588)
Cash and cash equivalents, beginning of period	6,446	11,034
Cash and cash equivalents, end of period	$ 2,507	$ 6,446
Supplemental disclosures of cash flow information:		
Cash paid for interest on senior secured credit facility	$ 3,082	$ 1,331
Cash paid for income taxes	874	2,804
Cash refunded from income taxes	1,000	—
Non-cash investing and financing transactions:		
Increase (decrease) in accrued capital expenditures for oil and natural gas properties	$ (79)	$ (1,969)
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	800	887
Accrued debt issuance costs	275	—
Accrued offering costs	10	—

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-in	Retained	Treasury	Total Stockholders'
	Shares	Par Value	Capital	Earnings	Stock	Equity
Balances at June 30, 2023	33,248	$ 33	$ 40,098	$ 51,963	$ —	$ 92,094
Issuance of restricted common stock	294	—	—	—	—	—
Common stock repurchases, including stock surrendered for tax withholding	—	—	—	—	(1,144)	(1,144)
Retirements of treasury stock	(202)	—	(1,144)	—	1,144	—
Stock-based compensation	—	—	2,137	—	—	2,137
Net income (loss)	—	—	—	4,080	—	4,080
Common stock dividends paid	—	—	—	(16,040)	—	(16,040)
Balances at June 30, 2024	33,340	$ 33	$ 41,091	$ 40,003	$ —	$ 81,127
Issuance of restricted common stock	376	—	—	—	—	—
Forfeitures of restricted stock	(8)	—	—	—	—	—
Common stock repurchases, including stock surrendered for tax withholding	—	—	—	—	(442)	(442)
Retirements of treasury stock	(89)	—	(442)	—	442	—
Issuance of common stock	718	1	3,839	—	—	3,840
Offering costs	—	—	(320)			(320)
Stock-based compensation	—	—	2,482	—	—	2,482
Net income (loss)	—	—	—	1,473	—	1,473
Common stock dividends paid	—	—	—	(16,347)	—	(16,347)
Balances at June 30, 2025	34,337	$ 34	$ 46,650	$ 25,129	$ —	$ 71,813

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Events and Accounting Policies

Nature of Operations. Evolution Petroleum Corporation ("Evolution," and together with its consolidated subsidiaries, the "Company") is an independent energy company focused on maximizing returns to shareholders through the ownership of and investment in onshore oil and natural gas properties in the United States. The Company's long-term goal is to maximize total shareholder return from a diversified portfolio of long-life oil and natural gas properties built through acquisitions and through selective development opportunities, production enhancement, and other exploitation efforts on its oil and natural gas properties.

The Company's oil and natural gas properties consist of non-operated interests in the following areas: the SCOOP and STACK plays of the Anadarko Basin located in central Oklahoma; the Chaveroo Field in Chaves and Roosevelt Counties of New Mexico; the Jonah Field in Sublette County, Wyoming; the Williston Basin in North Dakota; the Barnett Shale located in North Texas; the Hamilton Dome Field located in Hot Springs County, Wyoming, a secondary oil recovery field utilizing water injection wells to pressurize the reservoir; the Delhi Holt-Bryant Unit in the Delhi Field in Northeast Louisiana, a CO_2 enhanced oil recovery project; the TexMex interests in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas; as well as small overriding royalty interests in four onshore Texas wells.

Principles of Consolidation and Reporting. The consolidated financial statements include the accounts of Evolution Petroleum Corporation and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements for the previous year may include certain reclassifications to conform to the current presentation.

Risk and Uncertainties. The Company's oil and natural gas interests are operated by third-party operators and involve other third-party working interest owners. As a result, the Company has limited ability to influence the operation or future development of such properties. However, the Company is proactive with its third-party operators to review the management of capital expenditures.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Significant estimates include (a) reserve quantities and estimated future cash flows associated with proved reserves, which may significantly impact depletion expense and potential impairments of oil and natural gas properties, (b) asset retirement obligations, (c) stock-based compensation, (d) fair values of derivative contract assets and liabilities, (e) income taxes and the valuation of deferred income tax assets, (f) commitments and contingencies, and (g) accruals of crude oil, natural gas, and NGL revenues and operating expenses. The Company analyzes estimates and judgments based on historical experience and various other assumptions and information that are believed to be reasonable. Estimates and assumptions about future events and their effects cannot be predicted with certainty and, accordingly, these estimates may change as additional information is obtained, as new events occur, and as the Company's environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

From time to time, the Company conducts joint venture audits of the operators of its oil and natural gas properties. Any audit findings are reflected in the consolidated financial statements once agreed upon by all parties. In fiscal year 2025, the Company received a credit adjustment of $1.9 million from one its operators at its Barnett Shale properties, recognized as a reduction to lease operating expenses and accounts payable.

Segment Information. The Company has one reportable segment, which focuses on the ownership of and investment in onshore oil and natural gas properties in the United States. The segment's revenues are derived from the Company's interests in the sales of crude oil, natural gas, and NGL production to customers in the United States. The Company evaluates performance based on various financial metrics, including but not limited to consolidated income or loss from operations, net revenue, and cash flow from operations. The Company's chief executive officer, chief operating officer, and chief financial officer together function as the chief operating decision maker ("CODM"). The CODM manages the Company's business activities as a single operating segment.

The accounting policies of the one reportable segment are identical to accounting policies described for the consolidated Company. The CODM uses income (loss), as reported in the consolidated statement of operations to measure segment profitability, assess performance, and manage strategic capital resources allocations. The measure of segment assets is reported as "Total assets" on the consolidated balance sheets. The significant expense categories regularly provided to and reviewed by the CODM are the expenses categories as noted on the consolidated statements of operations.

Cash and Cash Equivalents. The Company considers all highly liquid investments, with original maturities of 90 days or less when purchased, to be cash and cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable consist of accrued hydrocarbon revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. The Company establishes provisions for losses on accounts receivable if it is determined that collection of all or a part of an outstanding balance is not probable. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2025 and 2024, no allowance for doubtful accounts was considered necessary.

Oil and Natural Gas Properties. The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. This includes any internal costs that are directly related to property acquisition, exploration, and development activities but does not include any costs related to production, general corporate overhead, or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

The depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of depletion, estimated future development costs, and asset retirement costs (net of salvage values) not included in oil and natural gas properties, less costs excluded from amortization. The depreciable base of oil and natural gas properties is amortized using the unit-of-production method over total proved reserves.

The capitalized costs of the Company's oil and natural gas properties, net of accumulated amortization and related deferred income taxes are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. Any excess over the full cost ceiling limitation is charged to expense as an impairment and is reflected as additional accumulated depletion, depreciation, and impairment or as a credit to oil and natural gas properties.

Oil and natural gas properties include costs that are excluded from the full-cost pool and depletion and amortization, which represent investments in unproved and unevaluated properties and include non-producing leasehold, geologic and geophysical costs associated with leasehold or drilling interests, and exploration drilling costs. These costs are excluded until the project is evaluated and proved reserves are established or impairment is determined. As of June 30, 2025 and 2024, the Company did not have any costs excluded from its full-cost pool or depletion and amortization.

Other Property and Equipment. Other property and equipment includes building leasehold improvements, data processing and telecommunications equipment, office furniture, and office equipment. These items are recorded at cost and depreciated over expected lives of the individual assets or group of assets, which range from three to seven years. The assets are depreciated using the straight-line method. Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. Repair and maintenance costs are expensed in the period incurred.

Asset Retirement Obligations. An asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred. It is associated with an increase in the carrying amount of the related long-lived asset, the Company's oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset. The initial recognition or subsequent revision of asset retirement cost is considered a Level 3 fair value measurement. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

Fair Value of Financial Instruments. The Company's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments, and debt. Except for derivatives, the carrying amounts of cash and cash equivalents, accounts receivable and accounts payable are short-term instruments and approximate fair value due to their highly liquid nature. The carrying amount of debt approximates fair value as the variable rates on the Senior Secured Credit Facility, as defined in Note 5, *"Senior Secured Credit Facility,"* are market interest rates. The fair values of the Company's derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and natural gas, discount rates, and volatility factors.

Concentrations of Credit Risk. The Company's primary concentrations of credit risk are the risks of uncollectible accounts receivable, and to a lesser extent, the non-performance by counterparties under the Company's derivative contracts, and cash and cash equivalent balances in excess of limits federally insured by the Federal Deposit Insurance Corporation.

Substantially all of the Company's accounts receivable as of June 30, 2025 and 2024 are from crude oil, natural gas, and NGL sales to third-party purchasers in the oil and natural gas industry. The Company holds working interests in crude oil and natural gas properties for which a third-party serves as operator. As a non-operator, the Company primarily markets its production through its field operators, except at the Jonah Field, where the Company takes its natural gas and NGL production in-kind. As a non-operator, the Company is highly dependent on the success of its third-party operators and the decisions made in connection with their operations. With the exception of the Jonah Field, the third-party operator sells the crude oil, natural gas, and NGLs to the purchaser, collects the cash, and distributes the cash to the Company. In the year ended June 30, 2025, three individual operators, Denbury (ExxonMobil), Diversified, and Foundation, each accounted for more than 10% of the Company's total revenues, collectively representing approximately 51% of the Company's total revenues for the year. In the year ended June 30, 2024, four individual operators, Denbury, Diversified, Foundation, and Merit, each accounted for more than 10% of the Company's total revenues, collectively representing approximately 69% of the Company's total revenues for the year. The majority of the Company's crude oil, natural gas, and NGL production is sold to purchasers under short-term (less than 12 months) contracts at market-based prices.

Derivative Instruments. The Company follows Accounting Standards Codification ("ASC") 815, *Derivatives and Hedging* ("ASC 815"). From time to time, in accordance with the Company's risk management strategy and with certain covenants under the Senior Secured Credit Facility, it may hedge a portion of its forecasted crude oil, natural gas, and NGL production. All derivative instruments are recorded on the consolidated balance sheet as either an asset or liability measured at fair value. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to an International Swap Dealers Association Master Agreement ("ISDA"); the agreement provides for net settlement over the term of the contract and in the event of default or termination of the contract. Although the derivative instruments provide an economic hedge of the Company's exposure to commodity price volatility, the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense and the estimated future net cash flows associated with those proved reserves is the basis for determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex and requires significant decisions in the evaluation of all available geologic, geophysical, engineering, and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information; this includes reservoir performance, additional development activity, new geologic and geophysical data, additional drilling, technological advancements, price changes, and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates prepared by the Company's third-party independent engineers represent the most accurate assessments possible, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in the Company's financial statements. Material revisions to reserve estimates and/or significant changes in commodity prices could substantially affect the Company's estimated future net cash flows of its proved reserves. These changes could affect the Company's quarterly ceiling test calculation and could significantly affect its depletion rate.

Income Taxes. The Company recognizes deferred income tax assets and liabilities based on the differences between the tax basis of assets and liabilities and its reported amounts in the financial statements that may result in taxable or deductible amounts in future years. The measurement of deferred income tax assets may be reduced by a valuation allowance based upon management's assessment of available evidence if it is deemed more likely than not that some or all of the deferred income tax assets will not be realizable. The Company recognizes a tax benefit from an uncertain position when it is more likely than not that the position will be sustained upon examination which is based on the technical merits of the position. The Company records the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement with a taxing authority. The Company classifies any interest and penalties associated with income taxes as income tax expense.

Earnings (Loss) Per Share. The Company grants restricted stock awards which entitle the recipient to all of the rights of a shareholder of the Company including non-forfeitable rights to receive all dividends or other distributions paid with respect to such share; therefore, it applies the two-class method of calculating basic and diluted earnings (loss) per share ("EPS") in accordance with ASC 260, *Earnings Per Share* ("ASC 260"). Basic EPS is computed by dividing earnings or loss available to common stockholders, after allocating undistributed earnings to participating securities, by the weighted-average number of common shares outstanding during the period. The computation of diluted EPS is similar to the computation of basic EPS, except that the denominator is increased to include the number of additional common shares that would have been outstanding if potentially dilutive common shares had been issued. Unvested performance-based restricted stock awards and unvested contingent restricted share units are only potentially dilutive if the awards meet their respective performance criteria as of the period end. The Company uses the treasury stock method to determine the effect of potentially dilutive common shares on diluted EPS, unless the effect would be anti-dilutive. The unamortized stock-based compensation expense related to unvested awards is assumed to be used to repurchase shares of common stock at the average market price during the period. The incremental shares (the difference between the number of shares assumed issued and the number of shares assumed repurchased) are included in the denominator of the diluted EPS computation. Awards with performance-based vesting restrictions are included in the computation of diluted shares, if dilutive, when the underlying performance conditions either (i) were satisfied as of the end of the reporting period or (ii) would be considered satisfied if the end of the reporting period were the end of the related contingency period.

Recently Issued Accounting Pronouncements

In November 2024, the FASB issued ASU 2024-03, *Disaggregation of Income Statement Expenses* (“ASU 2024-03”). ASU 2024-03 increases the transparency of expense information presented in the statement of operations through disclosures of expanded disaggregation of relevant expense captions including purchases of inventory, employee compensation, depletion, depreciation, and amortization. ASU 2024-03 is effective for annual periods beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027 with early adoption permitted. The Company is currently evaluating ASU 2024-03 and the impact it may have to the Company’s disclosures.

In December 2023, the FASB issued ASU 2023-09, *Improvements to Income Tax Disclosures* (“ASU 2023-09”). ASU 2023-09 enhances the transparency of income tax disclosures by expanding the income tax rate reconciliation disclosure and income taxes paid information. ASU 2023-09 also includes certain other amendments to improve the effectiveness of income tax disclosures. ASU 2023-09 is effective for annual periods beginning after December 15, 2024. The Company is currently evaluating ASU 2023-09 and the impact it may have to the Company’s financial position, results of operations, cash flow or disclosures.

In November 2023 the FASB issued ASU 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures* (“ASU 2023-07”). ASU 2023-07 expands the segment disclosures, even for entities with only one reportable segment, to include additional information about significant segment expenses and other segment items on an annual and interim basis as well as the title and position of the chief operating decision maker. ASU 2023-07 is effective for annual periods beginning after December 15, 2023 and interim periods withing fiscal years beginning after December 15, 2024. Early adoption is permitted and entities must adopt the amendment retrospectively for all prior periods presented in the financial statements. The Company adopted ASU 2023-07 as of June 30, 2025 with no significant impact to the Company’s financial position, results of operations, cash flow or disclosures.

Other accounting pronouncements that have recently been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company’s financial position, results of operations, cash flows or disclosures.

Note 2. Revenue Recognition

The Company’s revenues are primarily generated from its crude oil, natural gas and NGL production from the SCOOP and STACK plays in central Oklahoma; the Chaveroo Field in Chaves and Roosevelt Counties of New Mexico; the Jonah Field in Sublette County, Wyoming; the Williston Basin in North Dakota; the Barnett Shale located in North Texas; the Hamilton Dome Field in Wyoming; the Delhi Field in Northeast Louisiana; and the TexMex interests in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas;. Additionally, an overriding royalty interest retained in a past divestiture of Texas properties provides de minimis revenue. The following table disaggregates the Company’s revenues by major product for the years ended June 30, 2025 and 2024 (in thousands):

	Years Ended June 30,	
	2025	2024
Revenues		
Crude oil	$ 51,102	$ 53,446
Natural gas	23,516	21,525
Natural gas liquids	11,222	10,906
Total revenues	$ 85,840	$ 85,877

In the Jonah Field, the Company has elected to take its natural gas and NGL working interest production in-kind and markets its NGL production to Enterprise Products Partners L.P. ("Enterprise") and its natural gas production to different purchasers.

The Company does not take production in-kind at any of its other properties and does not negotiate contracts with customers for such production. The Company recognizes crude oil, natural gas, and NGL production revenue at the point in time when custody and title ("control") of the product transfers to the customer. The sales of oil and natural gas are made under contracts which the Company's third-party operators of its wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company typically receives payment from the sale of oil and natural gas production one to two months after delivery.

Judgments made in applying the guidance in ASC 606, *Revenue from Contracts with Customers*, relate primarily to determining the point in time when control of product transfers to the customer. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's contractual performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied upon control of produced hydrocarbons transferring to a customer at a specified delivery point. Consideration is allocated to completed performance obligations at the end of an accounting period.

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received by field operators one to two months before the Company receives payment and documentation from the operator, which is typical in the oil and natural gas industry. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for the sale of the product. To estimate accounts receivable from operators' contracts with customers, the Company uses knowledge of its properties, information from field operators, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors. Because the contractual performance obligations have been satisfied and an unconditional right to consideration exists as of the balance sheet date, the Company recognized amounts due from contracts with field operators as *"Receivables from crude oil, natural gas, and natural gas liquids revenues"* on the consolidated balance sheets. Differences between estimates and actual amounts received for product sales are recorded in the month that payments received from purchasers are remitted to the Company by field operators.

Note 3. Acquisitions

TexMex Acquisition

On April 14, 2025, the Company closed the acquisition of non-operated working interests in certain oil and natural gas wells located primarily in Lea, Eddy and Chaves Counties, New Mexico and Stephens County, Texas (the "TexMex Acquisition") from a private seller. The total purchase price for the TexMex Acquisition was approximately $9.0 million before customary post-closing adjustments, with an effective date of February 1, 2025. The Company funded the purchase price for the TexMex Acquisition through a combination of cash on hand and borrowings under its Senior Secured Credit Facility.

The TexMex Acquisition includes an average working interest of 42% and an average revenue interest of 35% in approximately 600 wells.

SCOOP/STACK Acquisitions

On February 12, 2024, the Company closed the acquisitions of certain non-operated oil and natural gas assets in the SCOOP and STACK plays in central Oklahoma (the "SCOOP/STACK Acquisitions") from Red Sky Resources III, LLC, Red Sky Resources IV, LLC, and Coriolis Energy Partners I, LLC. After including customary closing adjustments and an effective date of November 1, 2023, total combined cash consideration for the SCOOP/STACK Acquisitions was approximately $39.1 million, which includes $43.9 million paid at closing less purchase price adjustments totaling approximately $4.8 million related to net cash flows received on the properties subsequent to closing. The Company accounted for these transactions as asset acquisitions and allocated the combined purchase price (including $0.3 million of transaction costs) to proved oil and natural gas properties. In addition, the Company recognized $0.1 million in non-cash asset retirement obligations, the estimated net present value of future net retirement costs. The transactions were funded with cash on hand and $42.5 million in borrowings under the Company's Senior Secured Credit Facility.

The acquired assets consist of an average net working interest of approximately 2.6%, in 266 producing wells in the SCOOP and STACK plays of the Anadarko Basin in Oklahoma.

Chaveroo Field Participation Agreement

On September 12, 2023, the Company entered into a Participation Agreement with PEDEVCO for the joint development of a portion of PEDEVCO's Permian Basin property in the Chaveroo Field, located in Chaves and Roosevelt Counties, New Mexico. In accordance with the Participation Agreement, the Company has the right, but not the obligation, to elect to participate and acquire a 50% working interest share in certain development blocks at a fixed price of $450 per net acre for up to a total of approximately 16,000 gross acres. The Participation Agreement does not include any of PEDEVCO's existing vertical or horizontal wells.

As of June 30, 2025, the Company has incurred approximately $1.1 million in exchange for a 50% working interest share in the existing leases associated with six development blocks. In fiscal year 2024, the Company participated in the drilling and completion of the first development block, consisting of three gross wells (1.5 net wells). During the year ended June 30, 2025, the Company participated in the drilling and completion of the second development block, consisting of four gross wells (2.0 net wells) which came online during the fourth fiscal quarter.

In accordance with the FASB's authoritative guidance on asset acquisitions, the Company allocated the cost of the above acquisitions to the assets acquired and liabilities assumed based on a relative fair value basis of the assets acquired and liabilities assumed, with no recognition of goodwill or bargain purchase gain recorded. Incremental legal and professional fees related directly to the acquisitions were capitalized as part of the acquisition cost. The fair value is 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 (exit price). Fair value measurements also utilize market assumptions of market participants.

Purchase of SCOOP/STACK Minerals

Subsequent to fiscal year-end, in August 2025, the Company closed on an acquisition of certain mineral and royalty interests in the SCOOP/STACK area of Oklahoma. See Note 14, "*Subsequent Events,*" for further details.

Note 4. Property and Equipment

Property and equipment as of June 30, 2025 and 2024 consisted of the following (in thousands):

	June 30, 2025	June 30, 2024
Oil and natural gas properties		
Property costs subject to amortization	$ 272,496	$ 249,559
Less: Accumulated depletion, depreciation, and impairment	(130,248)	(109,874)
Oil and natural gas properties, net	$ 142,248	$ 139,685

The Company uses the full cost method of accounting for its investments in oil and natural gas properties. All costs of acquisition, exploration, and development of oil and natural gas reserves are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs would be charged to expense as a write-down of oil and natural gas properties.

Additionally, the Company assesses all properties classified as unevaluated property on a quarterly basis for possible impairment. The Company assesses properties on an individual basis or as a group, if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the full cost ceiling test limitation.

As of June 30, 2025 and 2024, all oil and natural gas property costs were subject to amortization. Depletion on oil and natural gas properties was $20.4 million and $18.6 million for the years ended June 30, 2025 and 2024, respectively. During the years ended June 30, 2025 and 2024, the Company incurred development capital expenditures of $13.2 million and $12.3 million, respectively.

At June 30, 2025, the ceiling test value of the Company’s reserves was calculated based on the first-day-of-the-month average for the 12-months ended June 30, 2025 of the West Texas Intermediate (“WTI”) crude oil spot price of $71.20 per barrel and Henry Hub natural gas spot price of $2.87 per MMBtu, adjusted by market differentials by field. The net price per barrel of NGLs was $25.24, which was based on historical prices received as NGLs do not have any single comparable reference index price. Using these prices, at June 30, 2025 the cost center ceiling was higher than the capitalized costs of oil and natural gas properties and, as a result, no write-down was applicable.

At June 30, 2024, the ceiling test value of the Company’s reserves was calculated based on the first-day-of-the-month average for the 12-months ended June 30, 2024 of the WTI crude oil spot price of $79.45 per barrel and Henry Hub natural gas spot price of $2.32 per MMBtu, adjusted by market differentials by field. The net price per barrel of NGLs was $23.86, which was based on historical prices received as NGLs do not have any single comparable reference index price. Using these prices, at June 30, 2024 the cost center ceiling was higher than the capitalized costs of oil and natural gas properties and, as a result, no write-down was applicable.

Note 5. Senior Secured Credit Facility

On April 11, 2016, the Company entered into a senior secured reserve-based credit facility with MidFirst Bank in an amount up to $50.0 million. On June 30, 2025, the Company entered into a syndicated amended and restated senior secured reserve-based credit facility (the “Senior Secured Credit Facility”) with MidFirst Bank, as administrative agent for the lenders party, thereto, in an amount up to $200.0 million with an initial and current borrowing base of $65.0 million, maturing on June 30, 2028. The borrowing base will be redetermined semiannually, with the lenders and the

Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of the Company's oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. The Senior Secured Credit Facility carries a commitment fee of 0.25% per annum on the undrawn portion of the borrowing base. Any borrowings under the Senior Secured Credit Facility will bear interest, at the Company's option, at either (i) the Secured Overnight Financing Rate ("SOFR"), subject to a minimum SOFR of 3.25%, plus a credit spread adjustment of 0.05%, or (ii) the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%, plus, in either case of (i) or (ii), an applicable margin of 2.75%.

The Company may elect, at its option, to prepay any borrowings outstanding under the Senior Secured Credit Facility without premium or penalty. Amounts outstanding under the Senior Secured Credit Facility are guaranteed by the Company's direct and indirect subsidiaries and secured by a security interest in substantially all of the properties of the Company and its subsidiaries. Borrowings under the Senior Secured Credit Facility may be used for the acquisition and for the drilling and development of oil and natural gas properties, investments in cash flow generating properties complimentary to the production of oil and natural gas, and for letters of credit or other general corporate purposes.

The Senior Secured Credit Facility contains certain events of default, including non-payment; breaches of representation and warranties; non-compliance with covenants; cross-defaults to material indebtedness; voluntary or involuntary bankruptcy; judgments and change in control. The Senior Secured Credit Facility also contains financial covenants including a requirement that the Company maintain, as of the last day of each fiscal quarter, (i) a maximum total leverage ratio of not more than 3.00 to 1.00, (ii) a current ratio of not less than 1.00 to 1.00, and (iii) a consolidated tangible net worth of not less than $40.0 million, each as defined in the Senior Secured Credit Facility. In addition, the Senior Secured Credit Facility contains hedging requirements that apply when utilization is greater than 25% of (x) the Margined Collateral Value, as defined under the Senior Secured Credit Facility, at any time when the leverage ratio is less than 2.25 to 1.00, or (y) the borrowing base, at any time when the leverage ratio is greater than or equal to 2.25 to 1.00. As of June 30, 2025, the Company had $37.5 million in borrowings outstanding under its Senior Secured Credit Facility, resulting in $27.5 million of available borrowing capacity. For the years ended June 30, 2025 and 2024, the weighted average interest rate on borrowings under the Senior Secured Credit Facility was 7.48% and 8.12%, respectively. As of June 30, 2025, the Company was in compliance with all covenants under the Senior Secured Credit Facility.

On March 7, 2025, the Company entered into a letter agreement with MidFirst Bank, which allows for the option to hedge 72% of expected natural gas production rather than hedging 25% of expected crude oil production in each month of the calendar year ending December, 31, 2026, as long as the Company remains in the 25% required hedging tier. See Note 7, *"Derivatives,"* for a listing of all crude oil and natural gas derivative contracts the Company has entered into.

On August 29, 2025, the Company entered into an amendment of its Senior Secured Credit Facility with MidFirst Bank, whereas it was determined for purposes of the hedge covenant that total crude oil and natural gas volumes from proved developed producing reserves will be combined on a barrels of oil equivalent basis to determine compliance with the required hedging covenant.

The Company capitalizes certain direct costs associated with the its Senior Secured Credit Facility and amortizes these costs over the life of the facility. For the year ended June 30, 2025, the Company capitalized $0.4 million of debt issuance costs in conjunction with amending and restating the Senior Secured Credit Facility. The debt issuance costs were presented in "Other Assets" on the consolidated balance sheet at June 30, 2025.

Note 6. Income Taxes

The Company files a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions in a timely manner.

There were no unrecognized tax benefits, nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2025 and 2024. The Company believes that it has appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on its assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's federal and state income tax returns are open to audit under the statute of limitations for the fiscal years ended June 30, 2021 through June 30, 2024 for federal tax purposes and for the fiscal years ended June 30, 2020 through June 30, 2024 for state tax purposes. To the extent the Company utilizes net operating losses ("NOLs") generated in earlier years, such earlier years may also be subject to audit.

Income tax (expense) benefit for the years ended June 30, 2025 and 2024 is comprised of the following (in thousands):

	June 30, 2025	June 30, 2024
Current:		
Federal	$ (462)	$ (898)
State	(402)	(620)
Total current income tax (expense) benefit	(864)	(1,518)
Deferred:		
Federal	584	59
State	(116)	42
Total deferred income tax (expense) benefit	468	101
Total income tax (expense) benefit	$ (396)	$ (1,417)

For the year ended June 30, 2025 the Company recognized income tax expense of $0.4 million and had an effective tax rate of 21.2% compared to income tax expense of $1.4 million and an effective tax rate of 25.8% for the year ended June 30, 2024. During each of the years ended June 30, 2025 and 2024, the Company recognized an income tax benefit of $0.1 million and less than $0.1 million, respectively, related to the vesting of restricted stock awards.

The Company's effective tax rate will typically differ from the statutory federal rate as a result of state income taxes, primarily in the states of Louisiana, North Dakota, Oklahoma and Texas, due to percentage depletion in excess of basis, and other permanent differences including federal tax credits expected from production on marginal natural gas wells. The following table presents the reconciliation of the Company's income taxes calculated at the statutory federal tax rate to the income tax (expense) benefit (in thousands):

	June 30, 2025	% of Income Before Income Taxes	June 30, 2024	% of Income Before Income Taxes
Income tax (expense) benefit computed at the statutory federal rate:	$ (392)	21.0 %	$ (1,154)	21.0 %
Reconciling items:				
Return to provision adjustments	(2)	0.1 %	3	(0.1)%
Depletion in excess of tax basis	59	(3.2)%	114	(2.1)%
State income taxes, net of federal tax benefit	(548)	29.3 %	(458)	8.4 %
Permanent differences related to stock-based compensation and other	(58)	3.1 %	80	(1.5)%
State valuation allowance	140	(7.5)%	—	— %
Marginal well credit	408	(21.8)%	—	— %
Other	(3)	0.2 %	(2)	0.1 %
Income tax (expense) benefit	$ (396)	21.2 %	$ (1,417)	25.8 %

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of net deferred income tax assets (liabilities) recognized are as follows (in thousands):

	June 30, 2025	June 30, 2024
Deferred tax assets:		
Non-qualified stock-based compensation	$ 599	$ 381
Net operating loss carry-forwards and other carry-forwards	148	313
Derivative losses	298	192
Asset retirement obligations	4,982	4,427
Other deferred tax assets	481	197
Total deferred tax assets	6,508	5,510
Deferred tax liabilities:		
Oil and natural gas properties	(12,742)	(12,072)
Total deferred tax liabilities	(12,742)	(12,072)
Valuation allowance	—	(140)
Net deferred tax liabilities	$ (6,234)	$ (6,702)

Evolution Petroleum OK, Inc., a wholly-owned subsidiary of the Company, had a prior year carryforward of NOLs of $8.9 million generated during tax years 2011 through 2017. In fiscal year 2024, in conjunction with the acquisition of oil and natural gas properties in Oklahoma by Evolution Petroleum OK, Inc., a deferred tax asset was recorded for a portion of this NOL carryforward. In fiscal year 2025, the valuation allowance of $0.1 million was released.

On July 4, 2025, President Trump signed into law the One Big Beautiful Bill Act ("OBBBA"). The OBBBA makes permanent key elements of the Tax Cuts and Jobs Act, including 100% bonus depreciation, domestic research cost expensing, and the business interest expense limitation. As the legislation was signed into law after the close of the fiscal year end, the impacts are not included in the Company's operating results as of and for the year-end June 30, 2025 as ASC 740, *"Income Taxes"*, requires the effects of changes in tax rates and laws on deferred tax balances to be recognized in the period in which the legislation is enacted. The Company is currently assessing the impact of the OBBBA on its consolidated financial statements, and while it does not expect it to have a material impact on its results of operations, it does expect it to provide a benefit to its cash flows from operating activities.

Note 7. Derivatives

The Company is exposed to certain risks relating to its ongoing business operations, including commodity price risk and interest rate risk. In accordance with the Company's strategy and the requirements under the Senior Secured Credit Facility (as discussed in Note 5, *"Senior Secured Credit Facility"*), it may hedge or may be required to hedge a varying portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company's hedge strategies and objectives may change significantly as its operational profile changes or as required under the Senior Secured Credit Facility. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial or commodity hedging institutions deemed by management as competent and competitive market makers. As of June 30, 2025, the Company did not post collateral under any of its derivative contracts during the periods in which contracts were open as they were secured under the Company's Senior Secured Credit Facility.

When the Company utilizes commodity derivative contracts, it expects to enter into deferred premium puts, costless put/call collars including two-way and three-way collars, fixed-price swaps, and/or basis swaps to hedge a portion of its anticipated future production. A two-way costless collar consists of a sold call, which establishes a maximum price the

Company will receive for the volumes under contract, and a purchased put that establishes a minimum price. Three-way collars are designed to establish a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) for the volumes under contract. Fixed-price swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for the volumes under contract. Basis swaps effectively lock in a price differential between regional prices (i.e., Inside FERC's Northwest Pipeline Corp Rocky Mountains) where the product is sold and the relevant pricing index under which the natural gas production is hedged (i.e., NYMEX Henry Hub). The Company may, from time to time, restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts. The Company has elected not to designate its open derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of the derivative contracts and all payments and receipts on settled derivative contracts in "*Net gain (loss) on derivative contracts*" on the consolidated statements of operations.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820, *Fair Value Measurement* ("ASC 820") and included in the consolidated balance sheets as assets or liabilities. The *"Derivative contract assets"* and *"Derivative contract liabilities"* represent the difference between the market commodity prices and the hedged prices for the remaining volumes of production hedges as of June 30, 2024 (the "mark-to-market valuation"). The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of June 30, 2025 and 2024 (in thousands):

Derivatives not designated as hedging contracts under ASC 815	**Balance sheet location**	**Derivative Contract Assets June 30, 2025**	**Derivative Contract Assets June 30, 2024**	**Balance sheet location**	**Derivative Contract Liabilities June 30, 2025**	**Derivative Contract Liabilities June 30, 2024**
Commodity contracts	Current assets - derivative contract assets	$ 1,777	$ 596	Current liabilities - derivative contract liabilities	$ 1,577	$ 1,192
Commodity contracts	Other assets - derivative contract assets	198	171	Long term liabilities - derivative contract liabilities	1,783	468
Total derivatives not designated as hedging contracts under ASC 815		$ 1,975	$ 767		$ 3,360	$ 1,660

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations for the years ended June 30, 2025 and 2024 (in thousands). "*Realized gain (loss) on derivative contracts"* represents all receipts (payments) on derivative contracts settled during the period. "*Unrealized gain (loss) on derivative contracts"* represents the net change in the mark-to-market valuation of the derivative contracts.

Derivatives not designated as hedging contracts under ASC 815	**Location of gain (loss) recognized in income on derivative contracts**	**Years Ended June 30, 2025**	**Years Ended June 30, 2024**
Commodity contracts:			
Realized gain (loss) on derivative contracts	Other income and expenses - net gain (loss) on derivative contracts	$ 965	$ (399)
Unrealized gain (loss) on derivative contracts	Other income and expenses - net gain (loss) on derivative contracts	(492)	(893)
Total net gain (loss) on derivative contracts		$ 473	$ (1,292)

As of June 30, 2025, the Company had the following open crude oil and natural gas derivative contracts:

Period	Commodity	Instrument	Volumes in MMBTU/BBL	Swap Price per MMBTU/BBL	Floor Price per MMBTU/BBL	Ceiling Price per MMBTU/BBL
July 2025 - September 2025	Crude Oil	Fixed-Price Swap	9,591	$ 60.50		
July 2025 - December 2025	Crude Oil	Fixed-Price Swap	11,880	72.00		
July 2025 - December 2025	Crude Oil	Fixed-Price Swap	81,335	71.40		
July 2025 - December 2025	Crude Oil	Fixed-Price Swap	18,748	61.02		
October 2025 - June 2026	Crude Oil	Fixed-Price Swap	43,656	61.00		
January 2026 - March 2026	Crude Oil	Two-Way Collar	43,493		$ 60.00	$ 75.80
April 2026 - June 2026	Crude Oil	Fixed-Price Swap	17,106	60.40		
April 2026 - September 2026	Crude Oil	Fixed-Price Swap	25,412	62.00		
July 2025 - December 2025	Natural Gas	Two-Way Collar	450,550		4.00	4.95
July 2025 - December 2026	Natural Gas	Fixed-Price Swap	2,546,138	3.60		
January 2026 - March 2026	Natural Gas	Two-Way Collar	213,251		4.00	5.39
January 2026 - March 2026	Natural Gas	Two-Way Collar	375,481		3.60	5.00
April 2026 - October 2026	Natural Gas	Two-Way Collar	952,588		3.50	4.55
July 2025 - December 2027	Natural Gas	Fixed-Price Swap	3,323,035	3.57		

Subsequent to June 30, 2025, the Company entered into the following new crude oil and natural gas derivative contracts:

Period	Commodity	Instrument	Volumes in MMBTU/BBL	Swap Price per MMBTU/BBL	Sub Floor Price per MMBTU/BBL	Floor Price per MMBTU/BBL	Ceiling Price per MMBTU/BBL
August 2025 - August 2026	Crude Oil	Two-Way Collar	83,458			$ 60.00	$ 65.55
September 2025 - December 2025	Crude Oil	Two-Way Collar	13,742			60.00	63.00
September 2025 - December 2025	Crude Oil	Two-Way Collar	3,798			60.00	63.50
September 2026 - December 2026	Crude Oil	Three-Way Collar	40,872		$ 50.00	60.00	70.45
September 2025 - December 2025	Natural Gas	Two-Way Collar	34,224			2.90	3.50
January 2026 - March 2026	Natural Gas	Two-Way Collar	76,177			3.50	4.66
July 2026 - December 2026	Natural Gas	Fixed-Price Swap	207,366	$ 3.98			
September 2026 - December 2026	Natural Gas	Two-Way Collar	318,964			3.75	4.94

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The following table shows the potential effects of master netting arrangements on the fair value of the Company's derivative contracts as of June 30, 2025 and 2024 (in thousands):

	Derivative Contract Assets		Derivative Contract Liabilities	
Offsetting of Derivative Assets and Liabilities	**June 30, 2025**	**June 30, 2024**	**June 30, 2025**	**June 30, 2024**
Gross amounts presented in the Consolidated Balance Sheet	$ 1,975	$ 767	$ 3,360	$ 1,660
Amounts not offset in the Consolidated Balance Sheet	(1,774)	(497)	(1,774)	(497)
Net amount	$ 201	$ 270	$ 1,586	$ 1,163

The Company enters into an ISDA with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

Note 8. Fair Value Measurement

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

The three levels are defined as follows:

Level 1—Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2—Other inputs that are observable directly or indirectly, such as quoted prices in markets that are not active or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3—Unobservable inputs for which there are little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair Value of Derivative Instruments. The Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. 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. ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable (Level 1) market corroborated (Level 2), or generally unobservable (Level 3). The Company classifies fair value balances based on observability of those inputs.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgement, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for any period presented in this report. The following table, set forth by level within the fair value hierarchy, shows the Company's financial assets and liabilities that were accounted for at fair value as of June 30, 2025 and 2024 (in thousands).

	June 30, 2025			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets				
Derivative contract assets	$ —	$ 1,975	$ —	$ 1,975
Liabilities				
Derivative contract liabilities	$ —	$ 3,360	$ —	$ 3,360

	June 30, 2024			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets				
Derivative contract assets	$ —	$ 767	$ —	$ 767
Liabilities				
Derivative contract liabilities	$ —	$ 1,660	$ —	$ 1,660

Derivative contracts listed above as Level 2 include fixed-price swaps and costless put/call collars that are carried at fair value. The Company records the net change in fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 7, *"Derivatives*," for additional discussion of derivatives.

The Company's derivative contracts are with large utilities with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts; however, the Company does not expect such nonperformance.

Other Fair Value Measurements. The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash and cash equivalents, accounts receivable, and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Senior Secured Credit Facility approximates carrying value because the interest rates approximate current market rates.

The Company follows the provisions of ASC 820, for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial measurement and any subsequent revision of ARO for which fair value is calculated using discounted future cash flows derived from historical costs and management's expectations of future cost environments. Significant Level 3 inputs used in the calculation of ARO include the costs of plugging and abandoning wells, surface restoration, and reserve lives. Subsequent to initial recognition, revisions to estimated asset retirement obligations are made when changes occur for input values. See Note 9, *"Asset Retirement Obligations*," for a reconciliation of the beginning and ending balances of the liability for the Company's ARO.

Note 9. Asset Retirement Obligations

The Company's ARO represents the estimated present value of the amount expected to be incurred to plug, abandon, and remediate its oil and natural gas properties at the end of their productive lives in accordance with applicable laws and regulations. The Company records the ARO liability on the consolidated balance sheets and capitalizes the cost in *"Oil and natural gas properties, net"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the consolidated statements of operations.

The following is a reconciliation of the activity related to the Company's ARO liability (inclusive of the current portion) for the years ended June 30, 2025 and 2024 (in thousands):

	June 30, 2025	June 30, 2024
Asset retirement obligations — beginning of period	$ 19,411	$ 17,067
Liabilities incurred	9	28
Liabilities settled	(230)	(39)
Liabilities acquired(1)	303	90
Accretion of discount	1,619	1,457
Revisions of previous estimates(2)	718	808
Asset retirement obligations — end of period	21,830	19,411
Less: current asset retirement obligations	(295)	(202)
Long-term portion of asset retirement obligations	$ 21,535	$ 19,209

(1) See Note 3, *"Acquisitions,"* for additional information on the Company's acquisition activities.
(2) Primarily related to upward revisions for increased cost estimates for the years ended June 30, 2025 and 2024.

Note 10. Commitments and Contingencies

The Company is subject to various claims and contingencies in the normal course of business. In addition, from time to time, the Company receives communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdictions in which the Company operates. The Company discloses such matters if it believes there is a reasonable possibility that a future event or events will confirm a material loss through impairment of an asset or the incurrence of a material liability. The Company accrues a material loss if it believes it probable that a future event or events will confirm a loss and the loss is reasonably subject to estimation. Furthermore, the Company will disclose any matter that is unasserted if it considers it probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable and material in amount. The Company expenses legal defense costs as they are incurred.

Note 11. Stockholders' Equity

Common Stock

As of June 30, 2025, the Company had 34,337,188 shares of common stock outstanding.

The Company began paying quarterly cash dividends on common stock in December 2013. As of June 30, 2025, the Company has cumulatively paid over $134.8 million in cash dividends. The Company paid dividends of $16.3 million and $16.0 million to its common stockholders during the years ended June 30, 2025 and 2024, respectively. The following table reflects the dividends paid per share within the respective quarterly periods:

	Fiscal Year	
	2025	2024
Fourth fiscal quarter	$ 0.12	$ 0.12
Third fiscal quarter	0.12	0.12
Second fiscal quarter	0.12	0.12
First fiscal quarter	0.12	0.12

On September 11, 2025, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2025. Refer to Note 14, *"Subsequent Events,"* for a further discussion.

On October 21, 2024, the Company entered into an At-the-Market ("ATM") equity Sales Agreement (the "ATM Sales Agreement") with Roth Capital Partners, LLC (the "Lead Agent"), Northland Securities Inc., and A.G.P./Alliance Global Partners pursuant to which the Company may issue and sell, from time to time, up to $30.0 million of shares of common stock through or to the Lead Agent, acting as agent or principal. For the year ended June 30, 2025, the Company sold a total of approximately 0.7 million shares of its common stock under the ATM Sales Agreement for net proceeds of approximately $3.5 million, after deducting $0.3 million in offering costs. The Company intends to use the net proceeds from any sales of common stock for general corporate purposes, including to repay outstanding indebtedness.

On September 8, 2022, the Board of Directors approved a share repurchase program, under which the Company was authorized to repurchase up to $25.0 million of its common stock in the open market through December 31, 2024. The Company funded repurchases from working capital and cash provided by operating activities. The share repurchase program was complimentary to the existing dividend policy and was a tax efficient means to further improve shareholder return. The shares were repurchased in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The Company repurchased a total of 0.8 million shares of its common stock under the program at a total cost of approximately $4.6 million, including incremental direct transaction costs.

In November 2023, the Company entered into a Rule 10b5-1 plan that authorized a broker to repurchase shares in the open market subject to pre-defined limitations on trading volume and price. The plan was effective until June 30, 2024 and had a maximum authorized amount of $0.8 million over that period. During the year ended June 30, 2024, 0.1 million shares of the Company's common stock were repurchased under the plan at a total cost of approximately $0.8 million, including incremental direct transaction costs. These treasury shares were subsequently cancelled.

During the years ended June 30, 2025 and 2024, the Company acquired treasury stock upon the ordinary course of scheduled vestings of employee stock-based awards to fund payroll tax withholding obligations. These treasury shares were subsequently cancelled. Such shares were valued at fair market value on the date of vesting. The following table summarizes all treasury stock purchases in the years ended June 30, 2025 and 2024 (in thousands, except per share amounts):

	Years Ended June 30,	
	2025	2024
Number of treasury shares acquired[(1)]	89	202
Average cost per share[(1)]	$ 5.01	$ 5.66
Total cost of treasury shares acquired	$ 442	$ 1,144

(1) For the year ended June 30, 2024, includes 140,672 shares repurchased under the Company's share repurchase program for a weighted average price of $5.33 per share.

Expected Tax Treatment of Dividends

For the fiscal year ended June 30, 2024, all common stock dividends for that fiscal year were treated for tax purposes as qualified dividend income to the recipients. Based on its current projections for the fiscal year ended June 30, 2025, the Company expects all common stock dividends for such period to be treated as qualified dividend income to the recipients.

Stock-Based Incentive Plan

The Evolution Petroleum Corporation 2016 Equity Incentive Plan (as amended the "2016 Plan"), authorizes the issuance of 3.6 million shares of common stock prior to its expiration on December 8, 2026. On December 5, 2024 shareholders approved and adopted the amendment and restatement of the 2016 Plan (hereinafter the "Amended and Restated Plan"), which increased the shares authorized for issuance under the 2016 Plan by 2.1 million shares to a maximum of 5.7 million shares. The duration of the Amended and Restated Plan is indefinite, provided that no new awards shall be made under the Amended and Restated Plan on or after the tenth anniversary of the date the stockholders approved the Amended and Restated Plan. Incentives under the Amended and Restated Plan may be granted to employees, directors, and consultants of the Company in any one or a combination of the following forms: incentive stock options, non-qualified stock options, stock appreciation rights, restricted awards, and performance share awards. As of June 30, 2025 and 2024, approximately 2.5 million shares and 0.9 million shares, respectively, remained available for grant under the Amended and Restated Plan.

The Company estimates the fair value of stock-based compensation awards on the grant date to provide the basis for future compensation expense. For the years ended June 30, 2025, and 2024, the Company recognized $2.5 million and $2.1 million, respectively, related to stock-based compensation expense recorded as a component of "*General and administrative expenses*" on the consolidated statements of operations.

Time-Vested Restricted Stock Awards

Time-vested restricted stock awards contain service-based vesting conditions and expire after a maximum of four years from the date of grant if unvested. The common shares underlying these awards are issued on the date of grant and participate in dividends paid by the Company. These service-based awards vest with continuous employment by the Company, generally in annual installments over terms of three to four years. Awards to the Company's directors generally have one-year cliff vesting. For such awards, grant date fair value is based on market value of the Company's common stock at the time of grant. This value is then amortized ratably over the service period. Previously recognized amortization expense subsequent to the last vesting date of an award is reversed in the event that the holder has no longer rendered service to the Company resulting in forfeiture of the award.

Performance-Based Restricted Stock Awards and Performance-Based Contingent Stock Units

Performance-based restricted stock awards and performance-based contingent stock units contain market-based vesting conditions based on the price of the Company's common stock compared to the performance of the common stock of its peers. The common shares underlying the Company's performance-based restricted stock awards are issued on the date of grant and participate in dividends paid by the Company and expire after a maximum of three years from the date of grant if unvested. Performance-based contingent share units do not participate in dividends and shares are only issued in part or in full upon the attainment of vesting conditions, generally have a lower probability of achievement and expire after a maximum of three years from the date of grant if unvested. Shares underlying performance-based contingent share units are reserved from the Amended and Restated Plan. Performance-based restricted stock awards and contingent restricted stock units are valued using a Monte Carlo simulation and geometric Brownian motion techniques applied to the historical volatility of the Company's total stock return compared to the historical volatilities of other companies or indices to which the Company compares its performance. Stock-based compensation is recognized ratably over the expected vesting period, so long as the award holder remains an employee of the Company. Previously recognized compensation expense is only reversed for the awards with market-based vesting conditions if the requisite service period is not rendered by the holder resulting in forfeiture of the award or as a result of regulatory required clawback.

Vesting of grants with performance-based vesting conditions is dependent on the future price of the Company's common stock. Such awards vest in part or in full if the trailing total returns on the Company's common stock for a specified three-year period exceed the corresponding total returns of various quartiles of indices consisting of peer companies.

For performance-based awards granted during the years ended June 30, 2025 and 2024, the assumptions used in the Monte Carlo simulation valuations were as follows:

	Years Ended June 30,	
	2025	2024
Weighted average fair value of performance-based awards granted	$ 3.90	$ 3.58
Risk-free interest rate	3.45%	4.87%
Expected term in years	2.78	2.77
Expected volatility	50.2%	55.0%
Dividend yield	8.4%	7.4%

Unvested restricted stock awards as of June 30, 2025 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Time-vested awards	348,143	$ 6.29
Performance-based awards	322,142	4.81
Unvested at June 30, 2025	670,285	$ 5.58

The following table sets forth the restricted stock award transactions for the years ended June 30, 2025 and 2024:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense (In thousands)	Weighted Average Remaining Amortization Period (Years)	Aggregate Intrinsic Value [(1)] (In thousands)
Unvested at June 30, 2023	595,414	$ 6.48			
Time-vested shares granted	157,692	6.22			
Performance-based shares granted	136,315	4.80			
Vested	(260,910)	5.85			
Unvested at June 30, 2024	628,511	$ 6.31	$ 2,492	1.8	$ 3,312
Time-vested shares granted	187,155	5.70			
Performance-based shares granted	189,477	4.82			
Vested	(326,431)	6.60			
Forfeited	(8,427)	6.05			
Unvested at June 30, 2025	670,285	$ 5.58	$ 2,196	1.6	$ 3,150

(1) *The intrinsic value of restricted stock was calculated as the closing market price on June 30, 2025 and 2024 of the underlying stock multiplied by the number of restricted shares that would be issuable. The total fair value of shares vested was $1.7 million and $1.6 million for the years ended June 30, 2025 and 2024, respectively.*

The following table sets forth contingent restricted stock unit transactions for the years ended June 30, 2025 and 2024:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense (In thousands)	Weighted Average Remaining Amortization Period (Years)	Aggregate Intrinsic Value [(1)] (In thousands)
Unvested at June 30, 2023	96,398	$ 3.49			
Performance-based awards granted	102,239	1.95			
Expired	(47,849)	2.19			
Unvested at June 30, 2024	150,788	$ 2.86	$ 230	1.6	$ 795
Performance-based awards granted	142,112	2.67			
Forfeited	(3,394)	2.91			
Expired	(47,893)	4.77			
Unvested at June 30, 2025	241,613	$ 2.37	$ 340	1.8	$ 1,136

(1) *The intrinsic value of contingent restricted stock units was calculated as the closing market price on June 30, 2025 and 2024 of the underlying stock multiplied by the number of restricted shares that would be issuable.*

Note 12. Earnings (Loss) per Common Share

The following table sets forth the computation of basic and diluted earnings (loss) per common share, reflecting the application of the two-class method (in thousands, except per share amounts):

	Years Ended June 30,	
	2025	2024
Numerator		
Net income (loss)	$ 1,473	$ 4,080
Undistributed earnings allocated to unvested restricted stock	(367)	(83)
Net income (loss) for earnings per share calculation	$ 1,106	$ 3,997
Denominator		
Weighted average number of common shares outstanding — Basic	33,158	32,691
Effect of dilutive securities:		
Unvested restricted stock awards	165	183
Unvested contingent restricted stock units	—	27
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share	33,323	32,901
Net income (loss) per common share — Basic	$ 0.03	$ 0.12
Net income (loss) per common share — Diluted	$ 0.03	$ 0.12

Unvested restricted stock awards (both time-vested and performance-based), totaling approximately 0.1 million for each of the year ended June 30, 2025 and 2024, were not included in the computation of diluted earnings per common share because the effect would have been anti-dilutive.

In addition, unvested performance-based restricted stock awards and unvested contingent restricted stock units that would not meet the performance criteria as of the period end are excluded from the computation of diluted earnings per common share.

Note 13. Additional Financial Statement Information

Certain amounts on the consolidated balance sheets are comprised of the following (in thousands):

	June 30, 2025	June 30, 2024
Prepaid expenses and other current assets:		
Other receivables	$ 227	$ 19
Prepaid insurance	701	734
Prepaid federal and state income taxes	706	1,798
Carryback of EOR tax credit	—	347
Advances to operators	316	608
Prepaid other	337	349
Total prepaid expenses and other current assets	$ 2,287	$ 3,855
Other assets:		
Deposit[(1)]	$ 8	$ 1,158
Debt issuance costs	365	—
Right of use asset under operating lease	58	140
Total other assets	$ 431	$ 1,298
Accrued liabilities and other:		
Accrued payables	$ 2,937	$ 2,570
Accrued capital expenditures	421	860
Accrued incentive and other compensation	1,472	945
Accrued royalties payable[(2)]	417	307
Accrued taxes other than federal and state income tax	1,283	1,062
Accrued settlements on derivative contracts	—	67
Operating lease liability	66	98
Asset retirement obligations due within one year	295	202
Accrued interest and other	18	128
Total accrued liabilities and other	$ 6,909	$ 6,239

(1) The deposit of $1.2 million at June 30, 2024, was related to a long-term gas gathering deposit with Enterprise for the Company's Jonah Field properties. During the current fiscal year, Enterprise returned the cash collateral and in return the Company issued a letter of credit to Enterprise subsequent to June 30, 2025.

(2) Accrued royalties payable relate to royalty and owner payments in the Jonah Field as the Company takes its natural gas and NGL working interest production in-kind. See Note 2, *"Revenue Recognition"* for a further discussion.

Note 14. Subsequent Events

Purchase of SCOOP/STACK Minerals

On August 4, 2025, the Company completed the acquisition of certain mineral and royalty interests in the SCOOP/STACK area of Oklahoma from a non-affiliated private seller (the "Minerals Acquisition") in a cash transaction valued at approximately $17.0 million, subject to customary post-closing adjustments. The Minerals Acquisition has an effective date of May 1, 2025. The Company funded the purchase price for the Minerals Acquisition with a combination of $15.0 million in borrowings under its Senior Secured Credit Facility and cash on hand. The acquired assets include an average royalty interest of 0.6% located on approximately 5,500 net royalty acres located primarily in Grady and Canadian Counties, Oklahoma.

Dividend Declaration

On September 11, 2025, the Company declared a quarterly cash dividend of $0.12 per share of common stock to shareholders of record on September 22, 2025 and payable on September 30, 2025.

Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)

Capitalized costs relating to oil and natural gas producing activities

The following table summarizes the amounts of capitalized costs relating to oil and natural gas producing activities and the amount of related accumulated depletion (in thousands).

	June 30, 2025	June 30, 2024	June 30, 2023
Oil and natural gas properties			
Property costs subject to amortization	$ 272,496	$ 249,559	$ 197,049
Less: Accumulated depletion, depreciation, and impairment	(130,248)	(109,874)	(91,268)
Oil and natural gas properties, net	$ 142,248	$ 139,685	$ 105,781

Costs incurred for oil and natural gas property acquisition, exploration, and development activities

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration, and development activities (in thousands). Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold, and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination, examining specific areas that are considered to have prospects containing oil and natural gas reserves, costs of drilling exploratory wells, geologic and geophysical assessment costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Development costs also include amounts incurred due to the recognition of asset retirement obligations of $0.8 million, $0.9 million, and $2.0 million during the years ended June 30, 2025, 2024, and 2023, respectively.

	For the Years Ended June 30,		
	2025	2024	2023
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$ 9,159	$ 39,153	$ 31
Unproved property	—	—	—
Exploration costs	—	—	—
Development costs	13,778	13,357	8,384
Total costs incurred for oil and natural gas activities	$ 22,937	$ 52,510	$ 8,415

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of net proved oil and natural gas reserves of the Company's oil and natural gas properties located entirely within the United States are based on evaluations prepared by third-party reservoir engineers, Cawley, Gillespie and Associates, Inc. ("CG&A") and DeGolyer & MacNaughton ("D&M"). Reserve volumes and values were determined under the method prescribed by the SEC for the fiscal years ended June 30, 2025, 2024 and 2023. SEC methodology requires the application of the previous 12-month unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected reserve life, when estimating whether reserve quantities are economical to produce.

Our policies regarding internal controls over reserves estimates require such estimates to be prepared by an independent petroleum engineering firm under the supervision of our internal reserve engineering team, which includes our Chief Operating Officer ("COO"), J. Mark Bunch. Our internal reserve engineering team and third-party consultants have a combined experience of over 80 years in Petroleum Engineering. Our COO, the person responsible for overseeing the preparation of our reserves estimates has a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, is a registered Professional Engineer in the State of Texas (No. 86704), has over 40 years of oil and natural gas experience including large independents and financial firm services for projects and acquisitions. Our Board of Directors also has oversight of our reserve estimation process and contains a Reserves Committee with William Dozier, an independent director who is a registered Professional Engineer in the State of Texas (No. 47279) with experience in energy company reserve evaluations. Such reserve estimates comply with generally accepted petroleum engineering and evaluation principles, definitions, and guidelines as established by the SEC.

The person responsible for the preparation of the reserve report at CG&A is W. Todd Brooker, P.E., President. Mr. Brooker received a Bachelor of Science degree in Petroleum Engineering in 1989 from the University of Texas at Austin and is a registered Professional Engineer in the State of Texas (No. 83462). Mr. Brooker joined CG&A in 1992 and has over 30 years of experience in engineering and geological services. The person responsible for the preparation of the reserve report at D&M is Dr. Dilhan Ilk, P.E, Executive Vice President. Dr. Ilk received a Bachelor of Science degree in Petroleum Engineering in 2003 from Istanbul Technical University and a Master's degree and Doctorate in Petroleum Engineering in 2005 and 2010, respectively, from Texas A&M University, and he has in excess of 15 years of experience in oil and natural gas reservoir studies and evaluations and is a licensed Professional Engineer in the state of Texas (No. 139334).

Proved oil and natural gas reserves are estimated quantities of oil, natural gas, and NGLs that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and natural gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Estimated quantities of proved oil, natural gas, and NGL reserves and changes in quantities of proved developed and undeveloped reserves for each of the periods indicated are as follows:

	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBOE)
Proved developed and undeveloped reserves:				
June 30, 2022	11,470	106,991	6,941	36,243
Revisions of previous estimates	(1,038)	(5,352)	(668)	(2,598)
Improved recovery, extensions and discoveries	98	33	20	124
Production (sales volumes)	(659)	(9,109)	(416)	(2,593)
June 30, 2023	9,871	92,563	5,877	31,176
Revisions of previous estimates	(1,420)	(21,448)	56	(4,939)
Improved recovery, extensions and discoveries	3,149	5,089	805	4,803
Purchase of reserves in place	919	9,948	652	3,230
Production (sales volumes)	(709)	(8,243)	(402)	(2,485)
June 30, 2024	11,810	77,909	6,988	31,785
Revisions of previous estimates	(1,640)	(14,706)	(1,901)	(5,993)
Improved recovery, extensions and discoveries	799	282	55	901
Purchase of reserves in place	1,925	6,429	—	2,996
Production (sales volumes)	(766)	(8,409)	(414)	(2,582)
June 30, 2025	12,128	61,505	4,728	27,107

	MBOE		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Proved developed and undeveloped reserves:			
June 30, 2022	32,646	3,597	36,243
Revisions of previous estimates	(2,580)	(18)	(2,598)
Improved recovery, extensions and discoveries	6	118	124
Production (sales volumes)	(2,593)	—	(2,593)
June 30, 2023	27,479	3,697	31,176
Revisions of previous estimates	(4,076)	(863)	(4,939)
Improved recovery, extensions and discoveries	293	4,510	4,803
Purchase of reserves in place	2,711	519	3,230
Transfers	118	(118)	—
Production (sales volumes)	(2,485)	—	(2,485)
June 30, 2024	24,040	7,745	31,785
Revisions of previous estimates	(2,446)	(3,547)	(5,993)
Improved recovery, extensions and discoveries	28	873	901
Purchase of reserves in place	2,996	—	2,996
Transfers	658	(658)	—
Production (sales volumes)	(2,582)	—	(2,582)
June 30, 2025	22,694	4,413	27,107

For the fiscal year ended June 30, 2025, notable changes in proved reserves included the following:

- *Purchase of reserves in place*. During the fiscal year ended 2025, the Company completed the TexMex Acquisition. See Note 3, "*Acquisitions*" for more details.
- *Improved recovery, extensions and discoveries*. During the fiscal year 2025, the Company added 0.9 MMBOE of proved reserves primarily associated with the addition of new PUDs for acreage acquired at Chaveroo Field in fiscal 2025.
- *Revisions of previous estimates.* Net Revisions in fiscal year 2025 totaled 6.0 MMBOE. Net negative oil revisions of 1.6 MMBOE were primarily associated with a 10.4% decline in SEC trailing 12-month pricing for oil from the prior fiscal year. Net negative natural gas and NGL revisions of 4.4 MMBOE were primarily associated with declines in price differentials received, specifically at Jonah Field, increases in lease operating costs at Barnett Shale, and drop-off of Williston Basin PUDs due to timing of future drilling plans. These metrics impacted the late-in-life economic limits of production.
- *Production*. The company produced 2.6 MBOE during the year ended June 30, 2025.

For the fiscal year ended June 30, 2024, notable changes in proved reserves include the following:

- *Improved recovery, extensions and discoveries*. During the fiscal year 2024, the Company added 4.8 MMBOE of proved reserves primarily associated with the addition of new PUDs at SCOOP/STACK, added subsequent to the acquisition date, for acreage acquired at Chaveroo Field, as well as, wells drilled and completed at Chaveroo Field in fiscal 2024.
- *Purchase of reserves in place*. During the fiscal year ended 2024, the Company completed the SCOOP/STACK Acquisition. See Note 3, "*Acquisitions*" for more details.
- *Revisions of previous estimates.* Net Revisions in fiscal year 2024 totaled 4.9 MMBOE primarily associated with the declines in SEC trailing 12-month pricing, especially for natural gas reserves where the price per MMBTU declined 51.5% from the prior year, as well as impacting the late-in-life economic limits of production.
- *Production*. The company produced 2.5 MBOE during the year ended June 30, 2024.

For the fiscal year ended June 30, 2023, notable changes in total proved reserves included the following:

- *Production*. The company produced 2.6 MBOE during the year ended June 30, 2023.
- *Improved recovery, extensions and discoveries*. During the fiscal year 2023, the Company added 0.1 MMBOE of proved reserves primarily associated with the addition of two new PUD wells at Delhi Field.

- *Revisions of previous estimates.* Net Revisions in fiscal year 2023 totaled 2.6 MMBOE primarily associated the Delhi Field and Barnett Shale. Reserve projections were revised downward at Delhi Field due to actual fiscal 2023 production coming in lower than fiscal year end 2022 projection. Additionally, Barnett Shale reserves decreased due primarily to increased production costs in the field shortening the economic life of many wells.

Future oil and natural gas sales, production, and development costs have been estimated using prices and costs in effect at the end of the years indicated, as required by ASC 932, *Extractive Activities - Oil and Gas* ("ASC 932"). ASC 932 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and natural gas reserves and for asset retirement obligations, assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow related to proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company's proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of the Company's proved reserves.

The Standardized Measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2025, 2024 and 2023 are as follows (in thousands):

	For the Years Ended June 30,		
	2025	**2024**	**2023**
Future cash inflows	$ 1,100,883	$ 1,250,176	$ 1,521,363
Future production costs and severance taxes	(642,213)	(748,927)	(860,054)
Future development costs	(136,491)	(139,628)	(120,648)
Future income tax expenses	(50,071)	(61,742)	(109,189)
Future net cash flows	272,108	299,879	431,472
10% annual discount for estimated timing of cash flows	(116,885)	(133,278)	(193,295)
Standardized measure of discounted future net cash flows	$ 155,223	$ 166,601	$ 238,177

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12-month unweighted arithmetic average first-day-of-the-month commodity prices for each year and reflect adjustments for lease quality, transportation fees, energy content, and regional price differentials.

	For the Years Ended June 30,		
NYMEX prices used in determining future cash flows:	**2025**	**2024**	**2023**
Oil (Bbl)	$ 71.20	$ 79.45	$ 83.23
Gas (MMBtu)	2.87	2.32	4.78

The NGL prices utilized for future cash inflows were based on historical prices received, where available.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil, natural gas, and NGL reserves is as follows (in thousands):

	For the Years Ended June 30,		
	2025	2024	2023
Balance, beginning of year	$ 166,601	$ 238,177	$ 314,783
Net changes in sales prices and production costs related to future production	(4,086)	(125,539)	(31,923)
Changes in estimated future development costs	(1,102)	1,081	(8,286)
Sales of oil, natural gas and NGLs produced, net of production costs	(36,502)	(37,604)	(68,969)
Net change due to extensions, discoveries, and improved recovery	6,793	52,014	4,695
Net change due to revisions in quantity estimates	(43,875)	(47,244)	(34,056)
Net change due to purchase of minerals in place	24,876	37,139	—
Development costs incurred during the period	9,516	933	—
Accretion of discount	20,289	30,121	40,382
Net change in discounted income taxes	5,841	26,743	26,006
Other	6,872	(9,220)	(4,455)
Balance, end of year	$ 155,223	$ 166,601	$ 238,177

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; this information is accumulated and communicated to our management, including our Principal Executive Officer and Principal Financial Officer, as appropriate to allow for timely decisions regarding required disclosure.

As required by Securities and Exchange Commission Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our Principal Executive Officer and Principal Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that the information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Generally accepted accounting principles include those policies and procedures that:

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Principal Executive Officer and the Principal Financial Officer, an evaluation was conducted on the effectiveness of our internal control over financial reporting based on criteria established in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Management concluded that we maintained effective internal control over financial reporting as of June 30, 2025.

Effective April 27, 2020, the Securities and Exchange Commission adopted certain amendments to the accelerated filer and large accelerated filer definitions to more appropriately tailor the types of issuers that are included in the categories of accelerated and large accelerated filers and to promote capital formation, preserve capital, and reduce unnecessary burdens for certain smaller issuers while maintaining investor protections. As a result of the amendments, certain low-revenue issuers will remain obligated, among other things, to establish and maintain internal control over financial reporting and have management assess the effectiveness of its internal control over financial reporting, but they will not be required to have their management's assessment of the effectiveness of internal controls over financial reporting attested to and reported on by an independent auditor. As a result, the effectiveness of our internal control over financial reporting as of June 30, 2025 has not been audited by Baker Tilly US, LLP, the independent registered public accounting firm that also audited our financial statements.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the three months ended June 30, 2025 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure regarding foreign jurisdictions that prevent inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2025 fiscal year.

Item 11. Executive Compensation

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2025 fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2025 fiscal year.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2025 fiscal year.

Item 14. Principal Accountant Fees and Services

Incorporated by reference to our Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days of the end of our 2025 fiscal year.

PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. **Financial Statements.**

   The consolidated financial statements of the Company and its subsidiaries are included in Part II, Item 8 of this report:

   Report of Independent Registered Public Accounting Firm
   Consolidated Balance Sheets
   Consolidated Statements of Operations
   Consolidated Statements of Cash Flows
   Consolidated Statements of Changes in Stockholders' Equity
   Notes to the Consolidated Financial Statements
   Supplemental Disclosure about Oil and Natural Gas Properties (unaudited)

2. **Financial Statements Schedules and Supplementary Information Required to be Submitted:**

   None.

3. **Exhibits**

   A list of the exhibits filed or furnished with this report on Form 10-K (or incorporated by reference to exhibits previously filed or furnished by us) is provided in the Exhibit Index of this report. Those exhibits incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Otherwise, the exhibits are filed herewith.

Item 16. Form 10-K Summary

None.

EXHIBIT INDEX

EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
3.1	Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q filed February 8, 2023)
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.3 of our Annual Report on Form 10-K filed September 13, 2023)
4.1	Description of Evolution Petroleum Corporations, securities registered under Section 12 of the Exchange Act (incorporated by reference to our Registration of Securities on Form 8-A filed July 13, 2006)
4.1.1	Specimen form of the Company's Common Stock Certificate (incorporated by reference to Exhibit 4.7 of our Registration Statement on Form S-3 filed June 19, 2013)
4.2	Majority Voting Policy for Directors (incorporated by reference to Exhibit 99.1 of our Current Report on Form 8-K filed October 31, 2012)
4.3†	2016 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed February 8, 2017)
4.4†	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan (incorporated by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q filed February 8, 2018)
4.4.1†	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (incorporated by reference to Exhibit 4.12 of our Annual Report on Form 10-K filed September 13, 2019)
4.4.2†	Form of Restricted Stock Agreement under 2016 Incentive Plan as revised on May 4, 2023 (incorporated by reference to Exhibit 4.4.2 of our Annual Report on Form 10-K filed September 13, 2023)
4.5†	Form of Contingent Restricted Stock Agreement under 2016 Equity Incentive Plan (incorporated by reference to Exhibit 4.2 of our Quarterly Report on Form 10-Q filed February 8, 2018)
4.5.1†	Form of Contingent Restricted Stock Agreement under 2016 Equity Incentive Plan as revised on May 4, 2023 (incorporated by reference to Exhibit 4.5.1 of our Annual Report on Form 10-K filed September 13, 2023)
4.6†	Form of Performance Share Unit Award Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (incorporated by reference to Exhibit 4.13 of our Annual Report on Form 10-K filed September 13, 2019)
4.7†	Amended and Restated 2016 Equity Incentive Plan (incorporated by reference to Exhibit 4.3 of our Quarterly Report on Form 10-Q filed February 12, 2025)
10.1	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed September 22, 2006)
10.2	Amended and Restated Credit Agreement dated June 30, 2025 between Evolution Petroleum Corporation and MidFirst Bank (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed July 2, 2025)
10.2.1	Letter Agreement to the Credit Agreement dated March 7, 2025 between Evolution Petroleum and MidFirst Bank (incorporated by reference to Exhibit 10.2.13 of our Quarterly Report on Form 10-Q filed May 14, 2025)
10.2.2*	Amendment to the Credit Agreement dated August 29, 2025, between Evolution Petroleum Corporation and MidFirst Bank
10.3	Settlement Agreement, dated June 24, 2016, by and among Denbury Onshore, LLC, Denbury Inc., NGS Sub Corp., Tertiaire Resources Company, and the Company (incorporated by reference to Exhibit 10.7 of our Annual Report on Form 10-K filed September 9, 2016)
10.5†	Employment Offer Letter to Ryan Stash dated October 9, 2020 (incorporated by reference to Exhibit 10.12 of our Annual Report on Form 10-K filed September 14, 2021)
10.6	Purchase and Sale Agreement, dated March 29, 2021, between Evolution Petroleum Corporation and TG Barnett Resources LLP (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on May 11, 2021)
10.6.1	First Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective April 20, 2021 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on May 11, 2021)

EXHIBIT NUMBER	DESCRIPTION
10.6.2	Second Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective May 4, 2021 (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed on May 11, 2021)
10.6.3	Third Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective May 6, 2021 (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed on May 11, 2021)
10.7	Purchase and Sale Agreement, dated January 14, 2022, between Evolution Petroleum Corporation, Foundation Energy Fund VII-A, LP and Foundation Energy Management, LLC (incorporated by reference to Exhibit 10.6 our Quarterly Report on Form 10-Q filed May 12, 2022)
10.8	Purchase and Sale Agreement, dated April 1, 2022, between Evolution Petroleum Corporation and Exaro Energy III, LL (incorporated by reference to Exhibit 10.7 of our Quarterly Report on Form 10-Q filed May 12, 2022)
10.9†	Employment Offer Letter to Kelly Loyd dated October 25, 2022 (incorporated by reference to Exhibit 10.9 of our Quarterly Report on Form 10-Q filed February 8, 2023)
10.10†	Employment Offer Letter to J. Mark Bunch dated February 21, 2023 (incorporated by reference to Exhibit 10.10 of our Quarterly Report on Form 10-Q filed May 10, 2023)
10.11	Purchase and Sale Agreement, dated February 12, 2024, between Evolution Petroleum Corporation and Red Sky Resources III, LLC (incorporated by reference to Exhibit 10.11 of our Quarterly Report on Form 10-Q filed May 8, 2024)
10.12	Purchase and Sale Agreement, dated February 12, 2024, between Evolution Petroleum Corporation and Red Sky Resources IV, LLC (incorporated by reference to Exhibit 10.12 of our Quarterly Report on Form 10-Q filed May 8, 2024)
10.13	Purchase and Sale Agreement, dated February 12, 2024, between Evolution Petroleum Corporation and Coriolis Energy Partners I, LLC (incorporated by reference to Exhibit 10.13 of our Quarterly Report on Form 10-Q filed May 8, 2024)
10.14	Sales Agreement, dated as of October 21, 2024, by and among the Company, Roth Capital Partners, LLC, Northland Securities Inc. and A.G.P./Alliance Global Partners (incorporated by reference to Exhibit 1.1 of our Current Report on Form 8-K filed October 21, 2024)
14.1	Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 of our Annual Report on Form 10-K filed September 14, 2021)
19.1*	Insider Trading Policy
21.1*	List of Subsidiaries of Evolution Petroleum Corporation
23.1*	Consent of Baker Tilly US, LLP
23.2*	Consent of Cawley, Gillespie and Associates, Inc.
23.3*	Consent of DeGolyer & MacNaughton
31.1*	Certification of Principal Executive Officer Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Principal Financial Officer Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	The summary of Cawley, Gillespie and Associates, Inc.’s Report as of June 30, 2025, on oil and gas reserves (SEC Case) dated August 19, 2025
99.2*	The summary of DeGolyer and MacNaughton’s Report as of June 30, 2025, on oil and gas reserves (SEC Case) dated August 20, 2025
97	Incentive Compensation Recoupment Policy (incorporated by reference to Exhibit 97 of our Annual Report on Form 10-K filed September 13, 2023)
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document

EXHIBIT NUMBER	DESCRIPTION
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 (embedded within the Inline XBRL document)

** Attached hereto.*

*** Furnished herewith.*

† Indicates management contract or compensatory plan or arrangement

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized in the City of Houston, Texas, on the date indicated.

Evolution Petroleum Corporation

Date: September 17, 2025

By: /s/ KELLY W. LOYD
Kelly W. Loyd
President and Chief Executive Officer
(Principal Executive Officer) and Director

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

Date	Signature	Title
September 17, 2025	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 17, 2025	/s/ KELLY W. LOYD Kelly W. Loyd	President and Chief Executive Officer (Principal Executive Officer) and Director
September 17, 2025	/s/ RYAN STASH Ryan Stash	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
September 17, 2025	/s/ KELLY M. BEATTY Kelly M. Beatty	Chief Accounting Officer (Principal Accounting Officer)
September 17, 2025	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 17, 2025	/s/ MYRA C. BIERRIA Myra C. Bierria	Director
September 17, 2025	/s/ WILLIAM DOZIER William Dozier	Director
September 17, 2025	/s/ MARJORIE A. HARGRAVE Marjorie A. Hargrave	Director