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, 2024

☐ 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	41-1781991
(State or other jurisdiction of incorporation or organization)	(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, 2023, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $5.81 on the NYSE American was $176.2 million.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 6, 2024, was 33,322,760.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2024 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
2024 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 and repurchase shares pursuant to our share repurchase program;
- 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 operating risks, including accidents, equipment failures, fires, and leaks of toxic or hazardous materials;
- estimates of our oil, natural gas and NGL reserves and recoverable quantities;
- our ability to access credit facilities and 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 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. 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 Securities and Exchange Commission.

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 Securities and Exchange Commission ("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 9, 2024, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2024.

SCOOP/STACK Acquisitions

On February 12, 2024, we 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 taking into account customary closing adjustments and an effective date of November 1, 2023, total combined cash consideration for the SCOOP/STACK Acquisitions was approximately $39.2 million, which includes $43.9 million paid at closing less purchase price adjustments totaling approximately $4.7 million related to net cash flows earned on the properties from the effective date to the closing date.

The acquired assets consist of an average net working interest of approximately 2.6% in 253 producing wells in the SCOOP and STACK plays of the Anadarko Basin in Blaine, Canadian, Carter, Custer, Dewey, Garvin, Grady, Kingfisher, McClain, Murray, and Stephens counties, Oklahoma. The acquisitions also include approximately 4,200 net acres with approximately 300 associated potential drilling opportunities.

Senior Secured Credit Facility

On February 12, 2024, we entered into an amendment to the Senior Secured Credit Facility. This amendment required that we enter into hedges for the next 12-month period, and on a rolling 12-month basis thereafter, covering expected crude oil and natural gas production from proved developed reserves, calculated separately, equal to a minimum of 40% of expected crude oil production each month, or 25% of expected crude oil and natural gas production each month over that period. We have the option to choose whether to hedge 40% of expected crude oil production or 25% of expected crude oil and natural gas production.

For further discussion of this amendment and 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*.

Appointment of Chief Accounting Officer

On December 18, 2023, we announced that the Board of Directors approved the appointment of Kelly M. Beatty as Chief Accounting Officer, effective January 1, 2024. Ms. Beatty has been serving as Principal Accounting Officer since December 2022 and has served as the Company's Controller since February 2022.

Share Repurchase Program

In November 2023, 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, 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. These shares were subsequently cancelled. We may enter into additional Rule 10b5-1 plans in the future, the terms of which will be approved by the Board of Directors.

Chaveroo Oilfield Participation Agreement

On September 12, 2023, we entered into a participation agreement (the "Participation Agreement") with PEDEVCO for the joint development of the Chaveroo oilfield, a conventional oil-bearing San Andres field located in Chaves and Roosevelt Counties, New Mexico (the "Chaveroo Field").

Pursuant to the Participation Agreement, we have the right, but not the obligation, to elect to participate in drilling locations on approximately 16,000 gross leasehold acres consisting of all leasehold rights from surface to the base of the San Andres formation, where PEDEVCO currently holds leasehold interest. We have agreed to pay PEDEVCO $450 per acre to acquire a 50% working interest share in the leases associated with the locations that we choose to participate in. The Participation Agreement initially includes up to 80 gross drilling locations across twelve development blocks. We have entered into a standard operating agreement with PEDEVCO serving as the operator with respect to the development of the properties. The Participation Agreement includes customary representations and warranties of the parties and other terms and conditions that are standard in such participation agreements.

As of June 30, 2024, we have incurred approximately $0.8 million, in exchange for a 50% working interest share in approximately 1,600 net acres, associated with five development blocks. As of June 30, 2024, we have participated in the drilling and completion of the first development block which consisted of three gross (1.5 net) wells. Refer to Capital Expenditures below for a further discussion of Chaveroo drilling and completion activities since entering into the Participation Agreement.

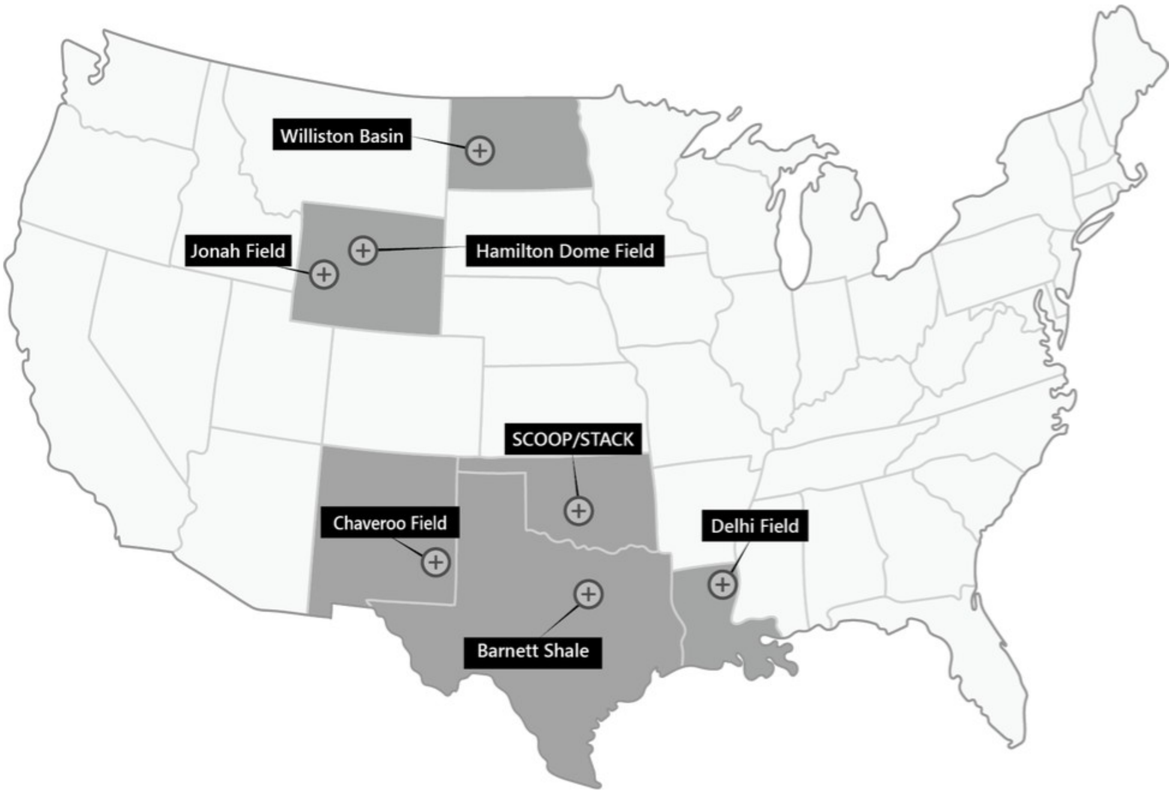
Business Strategy

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 of non-operated interests in the following areas: the SCOOP and STACK plays of the Anadarko Basin located in central Oklahoma; the Chaveroo oilfield 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; the Delhi Holt-Bryant Unit in the Delhi Field in Northeast Louisiana; as well as small overriding royalty interests in four onshore central Texas wells.



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 4,200 net acres (approximately 96% 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.

Average net daily production from the date of acquisition through June 30, 2024 was 1.4 MBOEPD. For the year ended June 30, 2024, our average net daily production from the SCOOP/STACK properties consisted of 47% natural gas, 37% 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 oilfield consist of a 50% net working interest, with an average associated 41% revenue interest, in approximately 1,600 net acres all held by production, associated with five 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”).

Average net daily production from the date of first production in February 2024 through June 30, 2024 was 0.2 MBOEPD. For the year ended June 30, 2024 our average net daily production from the Chaveroo Field properties consisted of 90% oil, 7% natural gas, and 3% NGLs. Oil produced from our Chaveroo Field properties is sold to various purchasers in New Mexico and 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 950 net acres all held by production. The properties are operated by Jonah Energy (“Jonah”).

For the year ended June 30, 2024 our average net daily production from the Jonah Field properties was 1.8 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 43,000 net acres (approximately 93% 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, 2024, our average net daily production from the Willison Basin properties was 0.5 MBOEPD consisting of 81% oil, 11% NGLs, and 8% 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 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, 2024, our average net daily production from the Barnett Shale properties was 2.6 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 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, 2024, 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”), which was acquired by Exxon Mobil Corporation (“ExxonMobil”) on November 2, 2023. The 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, 2024, our average net daily production from the Delhi Field properties was 1.0 MBOEPD consisting of 78% oil and 22% 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 Securities and Exchange Commission (“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 2024

Our proved reserves as of June 30, 2024, denominated in thousands of barrels of oil equivalent (“MBOE”), were estimated by our independent reservoir engineers, Netherland, Sewell & Associates, Inc. (“NSAI”), DeGolyer and MacNaughton (“D&M”) and Cawley, Gillespie and Associates, Inc. (“CG&A”), all worldwide petroleum consultants.

NSAI evaluated the reserves for our SCOOP/STACK, Jonah Field and Williston Basin properties. NSAI began evaluating these properties when we acquired each of them. 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.

CG&A evaluated the reserves for our Chaveroo Field properties. CG&A has a history with the field as it evaluates reserves for the operator of the field. The scope and results of their procedures are summarized in a letter from the firm, which is included as Exhibit 99.3 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved reserves as of June 30, 2024. For additional reserve 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 $79.45 per barrel of oil and $2.32 per MMBtu of natural gas. The net price per barrel of NGLs was $23.86, 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 based on quality, processing, transportation, location and other pricing aspects for each individual property and product.

Proved Reserves as of June 30, 2024

Reserve Category	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total Proved Reserves (MBOE)[(1)]	Percent of Total Proved Reserves
Proved:					
Developed Producing	7,746	66,627	5,065	23,917	75.2 %
Developed Non-Producing	108	33	9	123	0.4 %
Undeveloped	3,956	11,249	1,914	7,745	24.4 %
Total Proved	11,810	77,909	6,988	31,785	100.0 %
Product Mix	37%	41%	22%	100%	
Total Proved by Property:					
SCOOP/STACK	1,277	12,314	787	4,116	13.0 %
Chaveroo Field	2,218	636	137	2,461	7.7 %
Jonah Field	239	25,113	318	4,744	14.9 %
Williston Basin	2,798	7,135	1,653	5,640	17.7 %
Barnett Shale	78	32,711	2,452	7,983	25.1 %
Hamilton Dome Field	2,182	—	—	2,182	6.9 %
Delhi Field	3,018	—	1,641	4,659	14.7 %
Total Proved	11,810	77,909	6,988	31,785	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 NSAI, D&M and CG&A. The person responsible for the preparation of the reserve report at NSAI is Matthew D. Pankey, P.E., Petroleum Engineer. Mr. Pankey, a licensed Professional Engineer in the State of Texas (No. 142931), has been practicing consulting petroleum engineering at NSAI since 2019 and has over six years of prior industry experience. Mr. Pankey received a Bachelor of Science degree in Chemical Engineering in 2012 from Auburn University. 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 14 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). 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.

We provide NSAI, D&M and CG&A 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 NSAI's, D&M's and CG&A's procedures, as well as their professional qualifications, are summarized in the letters included as Exhibit 99.1, Exhibit 99.2 and Exhibit 99.3, respectively, to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

During the year ended June 30, 2024 our proved undeveloped ("PUD") reserves changed as follows:

Proved undeveloped reserves:	**Oil (MBbls)**	**Natural Gas (MMcf)**	**NGLs (MBbls)**	**Total Reserves (MBOE)**[(1)]
June 30, 2023	2,687	2,431	605	3,697
Revisions of previous estimates	(1,557)	1,802	393	(863)
Improved recovery, extensions and discoveries	2,891	5,005	785	4,510
Purchase of reserves in place	33	2,011	151	519
Transfers	(98)	—	(20)	(118)
June 30, 2024	3,956	11,249	1,914	7,745

(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 7.7 MMBOE as of June 30, 2024, with related future development costs of approximately $90.5 million, which are primarily associated with the Williston Basin and Chaveroo Field and to a lesser extent our SCOOP/STACK properties, where we hold a smaller average net working interest, and the Delhi Field. Extensions of 4.5 MMBOE are primarily associated with new wells at SCOOP/STACK, subsequent to our acquisition, and Chaveroo Field. Transfers of 0.1 MMBOE are associated with two Delhi wells placed online during the first fiscal quarter of 2024. The net downward revisions were due primarily to adjustments made to the Williston Basin development plan. These adjustments include updated economic assumptions to drill and complete wells, changes to the specific well locations on the drilling plan based on continuous technical analysis of the acreage, and the development timing of the project that maximizes the efficiency of our capital projects. The positive revisions in natural gas and NGLs are associated with changes in type curves at SCOOP/STACK subsequent to our acquisition. 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 Williston Basin, Chaveroo Field, SCOOP/STACK and Delhi Field.

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 2025 in the Jonah Field, the Barnett Shale, and the Hamilton Dome Field. At this time, operators of our properties at SCOOP/STACK, Williston Basin, Hamilton Dome Field and Delhi Field are periodically running workover rigs focusing on projects to return wells to production that have experienced mechanical issues.

At SCOOP/STACK, we currently expect 13 gross wells to be brought online during fiscal year 2025. 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, the next development block is currently planned to begin drilling during the second quarter of fiscal 2025, with production estimated to commence during the second half of fiscal 2025. At the Williston Basin, we anticipate that fiscal year 2025 will be used to finalize permits, maximize economic efficiencies in vendor contracts, and prepare for initiating a drilling program to exploit the Three Forks formation on our acreage. We envision production to begin in the second quarter of fiscal year 2026. At Delhi Field, the third-party operator is planning to drill three new wells within Test Site V. The first of these three new wells is expected to come online during the second half of fiscal 2025.

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,					
	2024		2023		2022	
	Volume	Price	Volume	Price	Volume	Price
Production:						
Crude oil (MBBL)						
SCOOP/STACK	71	$ 79.77	—	$ —	—	$ —
Chaveroo Field	27	77.90	—	—	—	—
Jonah Field	34	78.51	36	84.58	10	112.50
Williston Basin	146	73.97	144	79.38	71	101.25
Barnett Shale	9	75.01	9	76.12	9	82.56
Hamilton Dome Field	142	65.18	149	65.18	150	76.03
Delhi Field	279	79.46	319	81.57	358	86.57
Other	1	78.79	2	88.03	21	58.57
Total	709	$ 75.38	659	$ 77.46	619	$ 85.11
Natural gas (MMCF)						
SCOOP/STACK	532	$ 2.46	—	$ —	—	$ —
Chaveroo Field	12	2.17	—	—	—	—
Jonah Field	3,448	3.55	3,675	$ 10.63	1,000	$ 7.80
Williston Basin	86	1.72	96	4.48	40	6.30
Barnett Shale	4,165	1.87	5,337	4.55	6,087	5.11
Other	—	—	1	4.66	14	1.21
Total	8,243	$ 2.61	9,109	$ 7.00	7,141	$ 5.49
Natural gas liquids (MBBL)						
SCOOP/STACK	30	$ 23.16	—	$ —	—	$ —
Chaveroo Field	1	21.93	—	—	—	—
Jonah Field	38	28.67	36	$ 34.76	12	$ 52.92
Williston Basin	20	21.85	24	27.23	10	38.50
Barnett Shale	233	27.61	274	32.54	256	46.91
Delhi Field	80	27.91	81	34.95	83	48.02
Other	—	—	1	26.15	3	18.33
Total	402	$ 27.13	416	$ 32.86	364	$ 46.89
Equivalent (MBOE) *(1)*						
SCOOP/STACK(2)	190	$ 40.43	—	$ —	—	$ —
Chaveroo Field(2)	30	72.10	—	—	—	—
Jonah Field(3)	647	24.76	685	63.37	189	50.57
Williston Basin(3)	180	63.10	184	68.12	88	88.93
Barnett Shale	936	15.93	1,173	28.89	1,280	34.27
Hamilton Dome Field	142	65.18	149	65.18	150	76.03
Delhi Field	359	68.03	400	72.13	441	79.32
Other	1	78.79	2	73.71	25	52.08
Total	2,485	$ 34.56	2,593	$ 49.56	2,173	$ 50.13
Average daily production (BOEPD) *(1)*						
SCOOP/STACK(2)	519		—		—	
Chaveroo Field(2)	82		—		—	
Jonah Field(3)	1,768		1,877		518	
Williston Basin(3)	492		504		241	
Barnett Shale	2,557		3,214		3,507	
Hamilton Dome Field	388		408		411	
Delhi Field	981		1,096		1,208	
Other	3		5		68	
Total	6,790		7,104		5,953	

(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 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.

(3) Average daily production presented in the table above represents our fiscal year production divided by 365 days in the year for fiscal years 2023 and 2022. At Williston and Jonah, our average daily production since their respective acquisition dates of January 14, 2022 and April 1, 2022 through June 30, 2022, was 0.5 MBOEPD and 2.1 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, 2024		2023		2022	
Lease operating costs	Amount	per BOE	Amount	per BOE	Amount	per BOE
SCOOP/STACK	$ 1,647	$ 8.71	$ —	$ —	$ —	$ —
Chaveroo Field	462	15.40	—	—	—	—
Jonah Field	9,101	14.09	12,350	18.03	2,990	15.82
Williston Basin	5,235	29.08	5,581	30.42	2,419	27.49
Barnett Shale	14,695	15.68	20,756	17.70	22,825	17.83
Hamilton Dome Field	5,722	40.37	5,574	37.45	5,480	36.53
Delhi Field	11,390	31.76	15,275	38.22	14,933	33.86
Other	21	9.10	9	3.35	10	0.40
Total	$ 48,273	$ 19.43	$ 59,545	$ 22.96	$ 48,657	$ 22.39

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, 2024.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	555	92.6	555	92.6
Natural gas	—	—	1,489	266.1	1,489	266.1
Total	—	—	2,044	358.7	2,044	358.7

Acreage

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2024. 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.

	Developed Acreage		Undeveloped Acreage		Total	
Field(1)	Gross	Net	Gross	Net	Gross	Net
SCOOP/STACK, Oklahoma	100,480	3,971	3,200	182	103,680	4,153
Chaveroo Field, New Mexico	480	240	2,768	1,384	3,248	1,624
Jonah Field, Wyoming	5,280	956	—	—	5,280	956
Williston Basin, North Dakota	124,800	37,306	18,560	5,661	143,360	42,967
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)	369,851	66,960	29,038	8,304	398,889	75,264

(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, none of such acreage is currently producing and our interests are subject to expiration if leases are not maintained by others or commercial production is not established. 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, 2024 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)]
2025	1,665
2026	860
2027	—
2028	—
2029 & beyond	389
	2,914

(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, 2024, four individual purchasers, 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. In the year ended June 30, 2023, three individual purchasers, Diversified, Denbury, and Conoco Phillips, each accounted for more than 10% of our total revenues, collectively representing approximately 65% 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. These factors include changes in supply and demand, the relative strength of the U.S. dollar, government regulation, weather, and actions of major foreign producers.

Oil and natural gas prices over the past few years have been volatile and we expect that volatility to continue. Worldwide factors such as global health pandemics, geopolitical, international trade disruptions and tariffs, macroeconomics, supply and demand, refining capacity, petrochemical production, and derivatives trading, among others, influence prices for oil, natural gas, and NGLs. Local and domestic factors also influence prices for oil, natural gas, and NGLs and include increasing or decreasing production trends, quality differences, regulation, legislation and transportation issues unique to certain producing regions and reservoirs.

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, and fixed-price 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.

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. But 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 our operations. 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 our operations 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," our operations 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 our operations 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. Our operations 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 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 impose 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 sets new emissions standards for certain equipment; requires routine monitoring for and repair of leaks at well sites, centralized production facilities, and compressor stations; limits flaring from existing oil wells; and prohibits 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 do provide phase-in periods for certain requirements. And State plans for existing sources are due 24 months after the rule's effective date. States can either adopt the rule's presumptive standards or develop their own requirements that are at least as strict as EPA's. These regulations or practices and any other new rules requiring the installation of more sophisticated pollution control equipment 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, 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. The Biden Administration reversed changes to NEPA rules enacted under the Trump Administration that had been intended to streamline NEPA review. The revised regulations lay the foundation for additional scrutiny of impacts on climate change, which could 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 include rejoining the Paris Agreement on climate change, the Biden Administration's commitment to cut greenhouse gas emissions by 2030 to 50-52 percent of 2005 levels, various executive orders, limiting land available for oil and gas leasing, the United States Methane Emissions Reduction Action Plan (intended to reduce overall methane emissions by 30% below 2020 levels by 2030), and Clean Air Act rules (such as regulation announced in December 2023 to reduce methane emissions from the oil and gas sector). The SEC even promulgated new rules in 2024 that would require disclosure of various specific risks related to climate but promptly issued an order staying their applicability pending resolution of legal challenges. In addition, 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. 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. But in 2022, the United States enacted the Inflation Reduction Act that, among other things, creates 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 proposed rule in December 2023 that would implement the program for collecting the annual "Waste Emissions Charge" on certain excess methane emissions from oil and gas facilities. By statute, the charge would be $900 per metric ton of methane for 2024, $1,200 per metric ton for 2025, and $1,500 per metric ton each year thereafter. 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. We cannot predict with any certainty at this time how these possibilities may affect our operations.

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. 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, 2024, 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 property accounting, 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 annual 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, discrimination, diversity, equity, and inclusion.

Sustainability and ESG

In fiscal year 2023, we formed a Sustainability Committee which is responsible for overseeing our Environmental Social Governance ("ESG") initiatives. In fiscal year 2021-2022, under the supervision of our Board of Directors, the Nominating and Corporate Governance committee, and senior management, the foundation of our sustainability efforts and CSR were led by an ESG Task Force. Evolution's most recent CSR was published in November 2023. This report is accessible on our website at www.evolutionpetroleum.com.

The ESG 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. Each year, we continue to disclose, enhance, implement, and provide training for a number of new and existing policies and procedures. These include, but are not limited to: implementing a charitable donation program and employee volunteer initiatives, an annual company-wide ESG training program for both the Board of Directors and our workforce, implementation of safety inspections and health and safety coordinators, and incorporating ESG considerations into our compensation structure.

We are committed to high standards of conduct and ethics in order 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.

Denbury Inc., the operator of our Delhi Field property, and now a subsidiary of ExxonMobil, is an industry leader in Carbon Capture, Utilization and Storage with a network of CO_2 EOR operations and the United States' largest operated system of CO_2 transmission pipelines. As of year-end 2022, Denbury reportedly injects over three million tons of captured industrial-sourced CO_2 annually, and has a goal to reach Net Zero for Scope 1, Scope 2 and Scope 3 CO_2 emissions by 2030, primarily through increasing the amount of captured industrial-sourced CO_2 used in their operations.

Jonah Energy, the operator of our Jonah Field property, is one of the leading sustainable natural gas producers in the U.S. In 2021, Jonah was the first and only U.S. company to achieve the Gold Standard Rating, announced by the United Nations Environment Programme International Methane Emissions Observatory.

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.

In fiscal year 2023, we implemented our first annual voluntary Environmental Operator Questionnaire to collect various environmental metrics on behalf of our third-party operators. In addition, we host regular operations meetings with our third-party operators in which we discuss asset level operations, expenses, any environmental issues and compliance, including ESG and health and safety related topics. The objectives of these endeavors are to obtain environmental data to better disclose the impact of operations, as well as to be better prepared to work with our operating partners in mitigating potential environmental impacts.

We report in our CSR the estimated Scope 1 and Scope 2 GHG emissions for our corporate office located in Houston, Texas. We are not required to and do not report Scope 1 GHG, or direct, emissions to the EPA as we are not the operator of our oil and natural gas properties, nor do we have financial control over our oil and natural gas properties and operations. We prefer to partner with third-party operators that work to reduce their Scope 1 GHG emissions, and we encourage them to accelerate their efforts as appropriate in this regard. Scope 2 GHG emissions are based on indirect emissions representing purchased electricity. We are one of many tenants leasing space in our corporate office building and do not know the actual amount of electricity used in our space. As such, we estimate our consumption by multiplying the electricity purchased for the entire building by the percentage of the floor area that we occupy. Water use is also reported in the CSR and is calculated in a similar fashion.

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. 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 and natural gas 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 and natural gas significantly influences our revenue, profitability, access to capital, capital spending, and future rate of growth. At June 30, 2024, approximately 37% of our proved reserves were oil reserves, 41% were natural gas and 22% 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 only with the requirements of 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 and natural gas 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 and natural gas 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 Chaveroo oilfield, 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, requires significant amounts of CO_2 reserves, development capital, and technical expertise, the sources of which to date have been committed by the operator. On November 2, 2023, ExxonMobil acquired Denbury. Additional capital remains to be invested to fully develop the EOR project and maximize the value of the properties. 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 third-party working interest owners, not by us. 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 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 and natural gas 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 and our stock price. 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 the operations of 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 and/or natural gas 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 and natural gas 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 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.

Our operations, funding required to develop and produce 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 operations, 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 our operations, acquisitions, exploitation, and development activities. We have, for instance, accessed our credit facility on a routine basis, including, recently, to fund acquisitions. As a result of our SCOOP/STACK Acquisitions, our credit facility has current availability of $10.5 million, and the maximum amount that may be outstanding under our credit facility at any one time is $50.0 million. Further, the size of our 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 lender to increase the size of our credit facility due to limitations that the lender has on the loans it may extend to a single borrower. While we may pursue a syndication or refinance of our credit facility to alleviate this issue, we may be unable to do so upon the terms that are favorable to us. 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 our 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 our operations and 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, and financial condition.

During the last few years, concerns over inflation, energy costs, volatile oil and natural gas 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 could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers', and customers' 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 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 could, among other things, impact the ability of our employees and contractors to perform their duties, cause increased technology and security risk due to extended and company-wide telecommuting, and lead to disruptions in our permitting activities and critical business relationships. 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 oilfield 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 oilfield 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 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, natural gas, and mineral production depends on good title to our property.

Good and clear title to our oil, natural gas, and mineral properties 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, 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 current Administration there is 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.

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, 2024, our executive officers and directors, in the aggregate, beneficially owned approximately 3.2 million shares, or approximately 9.5% of our outstanding common stock and, based on recent filings with the SEC, we believe one large unaffiliated fund complex owned in excess of 7% 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, reduced 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 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. 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 have 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. For example, in December 2020, the State of New York announced that it will be divesting the state's Common Retirement Fund from fossil fuels. If this or similar 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 are also increasing their focus on 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 require disclosure of various specific risks related to climate but promptly issued an order staying their applicability pending resolution of legal challenges. The growing emphasis on ESG may lead the investment community to screen our ESG performance before investing in our common stock or debt securities or lending to us. Over the past few years there also has been an acceleration in investor demand for ESG investing opportunities, and many large institutional investors have committed to increasing the percentage of their portfolios that are allocated towards ESG-focused investments. As a result, there has been a proliferation of ESG-focused investment funds seeking ESG-oriented investment products.

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.

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, 2024, there were 33,339,535 shares of common stock issued and outstanding. As of September 1, 2024, there were approximately 219 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	
	2024	2023
Fourth quarter ended June 30,	$ 0.12	$ 0.12
Third quarter ended March 31,	0.12	0.12
Second quarter ended December 31,	0.12	0.12
First quarter ended September 30,	0.12	0.12

As of June 30, 2024, we have paid 43 consecutive quarterly dividends on our common stock. In September 2024, the Company declared a $0.12 per share dividend payable on September 30, 2024. 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	150,788 (1)	—	
Total	150,788	—	881,652
Equity compensation plans not approved by security holders	—	—	—
Total	150,788	$ —	881,652

(1) 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. As of June 30, 2024, we have granted 2.7 million equity awards under the 2016 Plan and 0.9 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, 2024.

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)[2]
April 2024	2,222	$ 5.94	—	$ 20,403
May 2024	—	—	—	20,403
June 2024	18,597	5.27	—	20,403

(1) During the three months ended June 30, 2024, no shares were purchased under the share repurchase program, discussed further below. All of the shares listed in the table above were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards.

(2) On September 8, 2022, the Company’s Board of Directors approved a share repurchase program, under which the Company is authorized to repurchase up to $25.0 million of its common stock in the open market through December 31, 2024. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will depend on a variety of factors, including management’s assessment of the intrinsic value of the Company’s shares, the market price of the Company's common stock, our capital needs and resources, general market and economic conditions, and applicable legal requirements. The value of shares authorized for repurchase by the Company's Board of Directors does not require the Company to repurchase such shares or guarantee that such shares will be repurchased, and the program may be suspended, modified, or discontinued at any time without prior notice. 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. We may enter into additional Rule 10b5-1 plans in the future, the terms of which will be approved by the Board of Directors.

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 of non-operated interests in the SCOOP and STACK plays of the Anadarko Basin located in central Oklahoma; the Chaveroo oilfield in Chaves and Roosevelt Counties of New Mexico; 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; the Delhi Holt-Bryant Unit in the Delhi Field in Northeast Louisiana; and small overriding royalty interests in four onshore central Texas wells.

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 4,200 net acres (approximately 96% 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 oilfield consist of a 50% net working interest, with an average associated 41% revenue interest, in approximately 1,600 net acres all held by production, associated with five 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"). See *"Chaveroo Oilfield Participation Agreement"* below for further information.

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 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 43,000 net acres (approximately 93% 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 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 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. The 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 9, 2024, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2024.

SCOOP/STACK Acquisitions

On February 12, 2024, we 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 taking into account customary closing adjustments and an effective date of November 1, 2023, total combined cash consideration for the SCOOP/STACK Acquisitions was approximately $39.2 million, which includes $43.9 million paid at closing less purchase price adjustments totaling approximately $4.7 million related to net cash flows earned on the properties from the effective date to the closing date.

The acquired assets consist of an average net working interest of approximately 2.6% in 253 producing wells in the SCOOP and STACK plays of the Anadarko Basin in Blaine, Canadian, Carter, Custer, Dewey, Garvin, Grady, Kingfisher, McClain, Murray, and Stephens counties, Oklahoma. The acquisitions also include approximately 4,200 net acres (approximately 96% held by production) with approximately 300 associated potential drilling opportunities.

Senior Secured Credit Facility

On February 12, 2024, we entered into an amendment to the Senior Secured Credit Facility. This amendment required that we enter into hedges for the next 12-month period, and on a rolling 12-month basis thereafter, covering expected crude oil and natural gas production from proved developed reserves, calculated separately, equal to a minimum of 40% of expected crude oil production each month, or 25% of expected crude oil and natural gas production each month over that period. We have the option to choose whether to hedge 40% of expected crude oil production or 25% of expected crude oil and natural gas production.

Appointment of Chief Accounting Officer

On December 18, 2023, we announced that the Board of Directors approved the appointment of Kelly M. Beatty as Chief Accounting Officer, effective January 1, 2024. Ms. Beatty has been serving as Principal Accounting Officer since December 2022 and has served as the Company's Controller since February 2022.

Share Repurchase Program

In November 2023, 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, 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. These shares were subsequently cancelled. We may enter into additional Rule 10b5-1 plans in the future, the terms of which will be approved by the Board of Directors.

Chaveroo Oilfield Participation Agreement

On September 12, 2023, we entered into a participation agreement (the "Participation Agreement") with PEDEVCO for the joint development of the Chaveroo oilfield, a conventional oil-bearing San Andres field located in Chaves and Roosevelt Counties, New Mexico (the "Chaveroo Field").

Pursuant to the Participation Agreement, we have the right, but not the obligation, to elect to participate in drilling locations on approximately 16,000 gross leasehold acres consisting of all leasehold rights from surface to the base of the San Andres formation, where PEDEVCO currently holds leasehold interest. We have agreed to pay PEDEVCO $450 per acre to acquire a 50% working interest share in the leases associated with the locations that we choose to participate in. The Participation Agreement initially includes up to 80 gross drilling locations across twelve development blocks. We have entered into a standard operating agreement with PEDEVCO serving as the operator with respect to the development of the properties. The Participation Agreement includes customary representations and warranties of the parties and other terms and conditions that are standard in such participation agreements.

As of June 30, 2024, we have incurred approximately $0.8 million in exchange for a 50% working interest share in approximately 1,600 net acres, associated with five development blocks. As of June 30, 2024, we have participated in the drilling and completion of the first development block which consisted of three gross (1.5 net) wells. Refer to Capital Expenditures below for a further discussion of Chaveroo drilling and completion activities since entering into the Participation Agreement.

Proved Reserves

The following table is a summary of our proved reserves as of June 30, 2024 and 2023:

	Proved Reserves		
	2024	**2023**	**Change**
Proved Reserves MMBOE	31.8	31.2	1.9 %
% Developed	75.6 %	88.1 %	(12.5)%
Liquids %	59.1 %	50.5 %	8.6 %
Standardized Measure ($MM)	$ 166.6	$ 238.2	(30.1)%

Proved oil equivalent reserves as of June 30, 2024 were 31.8 MMBOE, a 0.6 MMBOE, or 1.9%, increase from the previous year of 31.2 MMBOE. The net increase in total proved reserves was primarily due extensions of 4.8 MMBOE primarily in Chaveroo Field and SCOOP/STACK as well as 3.2 MMBOE of reserves purchased in our SCOOP/STACK acquisition. These increases are partially offset by production of 2.5 MMBOE and net negative revisions of 4.9 MMBOE. Net negative revisions of 4.9 MMBOE are primarily due to 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.

The Standardized Measure for proved reserves decreased 30.1% to $166.6 million, primarily due to decreases in the SEC mandated trailing 12-month average first day of the month prices for oil and natural gas and the price received for our NGLs; sales of oil, natural gas and NGLs produced during the period; and decreases in reserves estimates partially offset by extensions in Chaveroo Field and SCOOP/STACK and our SCOOP/STACK Acquisition. Prices decreased from $83.23 per barrel of oil, $4.78 per MMBtu of natural gas and $33.71 per barrel of NGLs at June 30, 2023 to $79.45 per barrel of oil, $2.32 per MMBtu of natural gas and $23.86 per barrel of NGLs at June 30, 2024. Our proved reserves consist of 37% oil, 41% natural gas, and 22% NGLs; 75.6% are classified as proved developed producing and 24.4% 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, 99.2, and 99.3 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 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 and natural gas prices have been, and we expect may continue to be, volatile. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may affect planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and 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.

The Federal Reserve has taken actions to raise interest rates in an attempt to tame inflation and slow the economy, which has contributed to volatility in markets.

Given the dynamic nature of these events, we cannot reasonably estimate the period of time that these market conditions will persist; predict the broader impact of liquidity concerns around financial institutions; the impact to long-term cost of capital or economic growth as a result of the Federal Reserve's policies; or the impact on the commodity prices that we realize.

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 capital expenditures and present alternative plans as necessary.

Liquidity and Capital Resources

As of June 30, 2024, we had $6.4 million in cash and cash equivalents and $39.5 million outstanding borrowings on our Senior Secured Credit Facility compared to $11.0 million in cash and cash equivalents and no borrowings outstanding on our Senior Secured Credit Facility at June 30, 2023. Our primary sources of liquidity and capital resources during the year ended June 30, 2024 were cash provided by operations as well as net borrowings under our Senior Secured Credit Facility. Our primary uses of liquidity and capital resources for the year ended June 30, 2024 were our SCOOP/STACK Acquisition, cash dividend payments to our common stockholders, and development capital expenditures, primarily at Chaveroo oilfield where we participated in the drilling of three gross (1.5 net) wells. As of June 30, 2024, working capital was $5.9 million, a decrease of $3.0 million from working capital of $8.9 million as of June 30, 2023.

The Senior Secured Credit Facility has a maximum capacity of $50.0 million subject to a borrowing base determined by the lender based on the value of our oil and natural gas properties. The Senior Secured Credit Facility has a current borrowing base of $50.0 million, with $39.5 million drawn as of June 30, 2024. The Senior Secured Credit Facility is secured by substantially all of our oil and natural gas properties and matures on April 9, 2026.

Borrowings bear interest, at our option, at either the SOFR plus 2.80% or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.0%. For the years ended June 30, 2024 and 2023, the weighted average interest on our borrowings was 8.12% and 5.25%, 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. It also contains other customary affirmative and negative covenants, including a hedging covenant discussed below, and events of default. As of June 30, 2024, we were in compliance with all covenants under the Senior Secured Credit Facility.

On February 12, 2024, we entered into an amendment to the Senior Secured Credit Facility. This amendment required that we enter into hedges for the next 12-month period, and on a rolling 12-month basis thereafter, covering expected crude oil and natural gas production from proved developed reserves, calculated separately, equal to a minimum of 40% of expected crude oil production each month, or 25% of expected crude oil and natural gas production each month over that period. We have the option to choose whether to hedge 40% of expected crude oil production or 25% of expected crude oil and natural gas production.

On May 5, 2023, we entered into the Tenth Amendment to the Senior Secured Credit Facility. This amendment, among other things, extended the maturity of our Senior Secured Credit Facility to April 9, 2026, converted our benchmark interest rate from LIBOR to SOFR plus a credit spread adjustment of 0.05%, and modified the Margined Collateral Value, as defined in the Ninth Amendment to the Senior Secured Credit Facility, to $95.0 million. We are required to enter into hedges on a rolling 12-month basis when the borrowings under the Senior Secured Credit Facility exceed 25% of the Margined Collateral Value. The required amount of hedged oil and natural gas production is related to the amount of borrowings outstanding. At each redetermination, our Margined Collateral Value takes into account the estimated value of our oil and natural gas properties, proved developed reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria.

On February 7, 2022, we entered into the Ninth Amendment to the Senior Secured Credit Facility. This amendment, among other things, modified the definition of utilization percentage related to the required hedging covenant such that for the purposes of determining the amount of future production to hedge, the utilization of the Senior Secured Credit Facility will be based on the Margined Collateral Value, as amended above, to the extent it exceeds the borrowing base then in effect. This amendment also required us to enter into hedges for the 12-month period ending February 2023, covering 25% of expected oil and natural gas production over that period.

On November 9, 2021, we entered into the Eighth Amendment to the Senior Secured Credit Facility. This amendment, among other things, increased the borrowing base to $50.0 million and added a hedging covenant whereby we must hedge a certain amount of our future production on a rolling 12-month basis when 25% or more of the borrowing base is utilized. The hedging covenant was amended in subsequent amendments, as discussed above.

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, existing working capital and, as needed, borrowings under our Senior Secured Credit Facility.

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 $10.5 million as of June 30, 2024. 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.

Our Board of Directors instituted a cash dividend on common stock in December 2013. We have since paid 43 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 9, 2024, the Board of Directors declared a quarterly cash dividend of $0.12 per share of common stock to shareholders of record on September 20, 2024 and payable on September 30, 2024.

On September 8, 2022, our Board of Directors approved a share repurchase program, under which we are authorized to repurchase up to $25.0 million of our common stock in the open market through December 31, 2024. We intend to fund any repurchases from working capital and cash provided by operating activities. 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 is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return.

In December 2022, we entered into a Rule 10b5-1 plan that authorizes a broker to repurchase shares in the open market subject to pre-defined limitations on trading volume and price. The plan included a 30-day cooling off period that did not allow repurchases to commence until January 2023. The plan was effective until June 30, 2023 and had a maximum authorized amount of $5.0 million over that period. During the year ended June 30, 2023, 0.6 million shares of our common stock were repurchased under the plan at a total cost of approximately $3.9 million, including incremental direct transaction costs. These treasury shares were subsequently cancelled.

In November 2023, 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, 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. These shares were subsequently cancelled. We may enter into additional Rule 10b5-1 plans in the future, the terms of which will be approved by the Board of Directors.

Capital Expenditures

For the year ended June 30, 2024, we incurred $12.3 million on development capital expenditures across our portfolio of assets, excluding acquisitions. At the Chaveroo Field, we purchased undeveloped acreage and also participated in drilling and completion of three gross (1.5 net) wells. First production on the three gross wells at Chaveroo Field occurred at the beginning of February 2024. We also participated in the drilling and completion of two new wells in the Delhi Field that came online during the first fiscal quarter of 2024. Since acquiring our SCOOP/STACK properties, we have participated in the drilling and completion of 14 gross wells.

Based on discussions with our operators, we expect capital workover projects to continue in all the fields. Overall, for fiscal year 2025, we expect budgeted capital expenditures to be in the range of $12.5 million to $14.5 million, which excludes any potential acquisitions. Our expected capital expenditures for the next 12 months include bringing approximately 13 gross wells online at our SCOOP/STACK properties, the drilling and completion of four new wells at Chaveroo Field, and the drilling and completion of one new well at Delhi Field Test Site V.

As of June 30, 2024, our PUD reserves included 7.7 MMBOE of reserves and approximately $90.5 million of future development costs primarily associated with the SCOOP/STACK, Chaveroo Field, and Williston Basin properties, and Test Site V at Delhi Field.

Funding for our anticipated capital expenditures over the near-term is expected to be met from cash flows from operations and current working capital, 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, 2024 were $79.45 per barrel of oil, $2.32 per MMBtu of natural gas and $23.86 per barrel of NGLs. As of June 30, 2024, 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, 2024 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, 2024, while all other factors remained constant, would not have generated an impairment.

Overview of Cash Flow Activities

	Years Ended June 30,		
	2024	2023	Change
Cash flows provided by operating activities	$ 22,729	$ 51,272	$ (28,543)
Cash flows used in investing activities	(49,633)	(6,992)	(42,641)
Cash flows provided by (used in) financing activities	22,316	(41,526)	63,842
Net increase (decrease) in cash and cash equivalents	$ (4,588)	$ 2,754	$ (7,342)

Cash provided by operating activities decreased $28.5 million during the fiscal year ended June 30, 2024 compared to fiscal year ended June 30, 2023 primarily due to a decrease in revenue. Total revenues decreased $42.6 million as compared to the prior year primarily due to lower commodity prices coupled with lower sales volumes. Our average realized price per barrel of oil equivalent ("BOE") decreased $15.00, or 30.3% from the prior year period. Refer to "*Results of Operations*" below for further information.

Cash used in investing activities for the year ended June 30, 2023 increased $42.6 million from the prior year primarily due to the acquisition of our SCOOP/STACK properties in February 2024 together with an increase in capital expenditures related to the drilling and completion of three gross (1.5 net) new wells in the Chaveroo Field and to a lesser extent, drilling and completion expenditures at Delhi Field and SCOOP/STACK. As of the year ended June 30, 2024, we have paid approximately $38.7 million for the SCOOP/STACK Acquisitions and have accrued purchase price adjustments of $0.5 million related to net cash flows due on the properties from the effective date to the closing date to arrive at a net purchase price of $39.2 million.

Net cash flows provided by financing activities for the year ended June 30, 2024 were $22.3 million compared to net cash flows used in financing activities of $41.5 million for the year ended June 30, 2023. In the current year period, we had net borrowings of $39.5 million under our Senior Secured Credit Facility to finance our SCOOP/STACK Acquisitions, $16.0 million cash dividends paid to our common stockholders together with $0.8 million paid to repurchase shares of common stock under our share repurchase plan. In the prior year period, we had repayments totaling $21.3 million of borrowings outstanding under our Senior Secured Credit Facility, $16.1 million in cash dividends paid to our common stockholders and $3.9 million paid to repurchase shares of common stock under our share repurchase program.

Results of Operations

Years Ended June 30, 2024 and 2023

We reported net income of $4.1 million and $35.2 million for the years ended June 30, 2024 and 2023, respectively. The following table summarizes the comparison of financial information for the periods presented:

(in thousands, except per unit and per BOE amounts)	Years Ended June 30, 2024	Years Ended June 30, 2023	Variance	Variance %
Net income (loss)	$ 4,080	$ 35,217	$ (31,137)	(88.4) %
Revenues:				
Crude oil	53,446	51,044	2,402	4.7 %
Natural gas	21,525	63,800	(42,275)	(66.3) %
Natural gas liquids	10,906	13,670	(2,764)	(20.2) %
Total revenues	85,877	128,514	(42,637)	(33.2) %
Operating costs:				
Lease operating costs:				
CO_2 costs	4,242	7,375	(3,133)	(42.5) %
Ad valorem and production taxes	5,281	8,158	(2,877)	(35.3) %
Other lease operating costs	38,750	44,012	(5,262)	(12.0) %
Depletion, depreciation, and accretion:				
Depletion of full cost proved oil and natural gas properties	18,605	13,142	5,463	41.6 %
Accretion of asset retirement obligations	1,457	1,131	326	28.8 %
General and administrative expenses:				
General and administrative	7,499	7,944	(445)	(5.6) %
Stock-based compensation	2,137	1,639	498	30.4 %
Other income (expense):				
Net gain (loss) on derivative contracts	(1,292)	513	(1,805)	(351.9) %
Interest and other income	342	121	221	182.6 %
Interest expense	(1,459)	(458)	(1,001)	218.6 %
Income tax (expense) benefit	(1,417)	(10,072)	8,655	(85.9) %
Production:				
Crude oil (MBBL)	709	659	50	7.6 %
Natural gas (MMCF)	8,243	9,109	(866)	(9.5) %
Natural gas liquids (MBBL)	402	416	(14)	(3.4) %
Equivalent (MBOE)[(1)]	2,485	2,593	(108)	(4.2) %
Average daily production (BOEPD)[(1)]	6,790	7,104	(314)	(4.4) %
Average price per unit[(2)]:				
Crude oil (BBL)	$ 75.38	$ 77.46	$ (2.08)	(2.7) %
Natural gas (MCF)	2.61	7.00	(4.39)	(62.7) %
Natural Gas Liquids (BBL)	27.13	32.86	(5.73)	(17.4) %
Equivalent (BOE)[(1)]	34.56	49.56	(15.00)	(30.3) %
Average cost per unit:				
Operating costs:				
Lease operating costs:				
CO_2 costs	$ 1.71	$ 2.84	(1.13)	(39.8) %
Ad valorem and production taxes	2.13	3.15	(1.02)	(32.4) %
Other lease operating costs	15.59	16.97	(1.38)	(8.1) %
Depletion of full cost proved oil and natural gas properties	7.49	5.07	2.42	47.7 %
General and administrative expenses:				
General and administrative	3.02	3.06	(0.04)	(1.3) %
Stock-based compensation	0.86	0.63	0.23	36.5 %

(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 $85.9 million and $128.5 million for the fiscal years ended June 30, 2024 and 2023, respectively. The decrease in revenues is primarily due to the decrease in our average realized price per BOE coupled with a decrease in our sales volumes. Our average realized commodity price (excluding the impact of derivative contracts) decreased approximately $15.00 per BOE, or 30.3%, for the fiscal year ended June 30, 2024 compared to June 30, 2023. 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. Realized natural gas prices decreased 62.7% from the prior fiscal year, which was the largest portion of the driver of the decrease in revenues. This was partially attributed to the prior fiscal year benefit of strong natural gas price differentials received at the Jonah Field where we realized an average natural gas price of $10.63 per MCF in the prior fiscal year compared to $3.55 for the current fiscal year. Average daily equivalent production decreased 4.4% from 7,104 BOEPD to 6,790 BOEPD in the current fiscal year as a result of natural production declines in our properties combined with operational issues and downtime at certain properties throughout the year. As of June 30, 2024, due to low natural gas prices, certain wells at Barnett Shale are shut-in and remain offline which has continued to negatively impact production volumes. The overall decrease in production was partially offset by the acquisitions of non-operated working interests in the SCOOP/STACK in February 2024 and first production at our wells in the Chaveroo Field in early February 2024, which collectively increased production for the year ended June 30, 2024 by approximately 601 BOEPD. Combined production at these two fields is primarily oil, thus increasing our oil volumes year over year.

Lease Operating Costs

Ad valorem and production taxes were $5.3 million and $8.2 million for the years ended June 30, 2024 and 2023, respectively. On a per unit basis, ad valorem and production taxes were $2.13 per BOE and $3.15 per BOE for the years ended June 30, 2024 and 2023, respectively. The decrease in ad valorem and production taxes is primarily due to decreases in our realized oil and natural gas prices as well as decreased production volumes described above as production taxes are based on sales at the wellhead.

The following table summarizes CO_2 costs per Mcf and CO_2 volumes for the years ended June 30, 2024 and 2023. CO_2 purchase costs are for the Delhi Field. Under our contract with the Delhi Field operator, purchased CO_2 is priced at 1% of the realized oil price in the field per Mcf, plus sales taxes and transportation costs as per contract terms.

	Years Ended June 30,			
	2024	2023	Variance	Variance %
CO_2 costs per MCF	$ 0.97	$ 0.99	$ (0.02)	(2.0) %
CO_2 volumes (MMCF per day, gross)	50.3	85.2	(34.9)	(41.0) %

The $3.1 million decrease in CO_2 costs for the fiscal year ended June 30, 2024 was primarily due to a 41.0% decrease in purchased CO_2 volumes combined with a 2.0% decrease in CO_2 costs per MCF, which was driven by a decrease in our average realized oil price. In February 2024, CO_2 purchased volumes were suspended due to maintenance on the CO_2 pipeline. CO_2 purchases provide approximately 20% of the injected volumes in the field and the field's recycle facilities provide the other 80%. We do not have any ownership in the CO_2 pipeline which is owned and operated by Denbury. On a per unit basis, CO_2 costs were $1.71 per BOE and $2.84 per BOE for the years ended June 30, 2024 and 2023, respectively. CO_2 purchases are expected to restart in early second quarter of fiscal 2025.

Other lease operating costs decreased $5.3 million, or 12.0%, compared to the prior fiscal year primarily due to lower production combined with the lower commodity price environment. On a per unit basis, other lease operating costs decreased to $15.59 per BOE in the current year from $16.97 per BOE in the prior year. The largest decrease in other lease operating costs is at our Barnett Shale properties and the Delhi Field. At the Barnett Shale, significant cost savings efforts are being prioritized due to the lower realized natural gas prices and the shut-in of certain low margin wells at current natural gas prices. We are incurring lower operating costs in all cost categories, especially lower water hauling costs and lower gathering, transportation and processing charges. At Delhi Field, we have seen lower electricity charges due to lower commodity prices and decreased electrical demand due the installation of heat exchangers. These decreases are partially offset by increases in other lease operating costs associated with our acquisitions of non-operated working interests in the SCOOP/STACK in February 2024 and first production at our wells in the Chaveroo Field in early February 2024.

Depletion of Full Cost Proved Oil and Natural Gas Properties

Depletion expense increased $5.5 million or 41.6% from $13.1 million for the fiscal year ended June 30, 2023 to $18.6 million for the fiscal year ended June 30, 2024 primarily due to an increase in the depletion rate. On a per unit basis, depletion expense was $7.49 per BOE and $5.07 per BOE for the fiscal years ended June 30, 2024 and 2023, respectively. The depletion rate of our unit of production calculation increased primarily due to an increase in our depletable base due to our SCOOP/STACK Acquisitions and capital expenditures since the prior year period.

General and Administrative Expenses

General and administrative expenses for the fiscal year ended June 30, 2024 decreased $0.4 million, or 5.6%, to $7.5 million compared to $7.9 million for the fiscal year ended June 30, 2023. The decrease primarily relates to lower consulting fees totaling approximately $0.3 million related to our search for a CEO in the prior year period. On a per unit basis, general and administrative expenses were $3.02 per BOE and $3.06 per BOE for the years ended June 30, 2024 and 2023, respectively.

Stock-based Compensation Expenses

Stock-based compensation increased $0.5 million to $2.1 million for the year ended June 30, 2024 compared to $1.6 million the prior period due primarily to the addition of new personnel and the associated new awards granted during the current year period to all staff and directors.

Net Gain (Loss) on Derivative Contracts

Periodically, we utilize commodity derivative financial instruments to reduce our exposure to fluctuations in oil and natural gas prices. 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.

	Years Ended June 30,			
(in thousands, except per unit and per BOE amounts)	**2024**	**2023**	**Variance**	**Variance %**
Realized gain (loss) on derivative contracts	$ (399)	$ (1,481)	$ 1,082	(73.1) %
Unrealized gain (loss) on derivative contracts	(893)	1,994	(2,887)	(144.8) %
Total net gain (loss) on derivative contracts	$ (1,292)	$ 513	$ (1,805)	(351.9) %
Average realized crude oil price per BBL	$ 75.38	$ 77.46	$ (2.08)	(2.7) %
Cash effect of oil derivative contracts per BBL	(0.56)	(0.37)	(0.19)	51.4 %
Crude oil price per Bbl (including impact of realized derivatives)	$ 74.82	$ 77.09	$ (2.27)	(2.9) %
Average realized natural gas price per MCF	$ 2.61	$ 7.00	$ (4.39)	(62.7) %
Cash effect of natural gas derivative contracts per MCF	—	(0.14)	0.14	(100) %
Natural gas price per Mcf (including impact of realized derivatives)	$ 2.61	$ 6.86	$ (4.25)	(62.0) %

As a result of our acquisitions during fiscal years 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 commodity prices since entering into the hedges and the continued increase in forward commodity prices resulted in a realized loss on hedges for the current year and an unrealized loss on the mark-to-market of our hedges. As of June 30, 2024, we had $0.8 million derivative assets, $0.6 million of which was classified as current, and a $1.7 million derivative liability, $1.2 million of which was classified as current.

Interest Expense

Interest expense increased $1.0 million during the fiscal year ended June 30, 2024 compared to fiscal year 2023 primarily due to borrowings drawn on our Senior Secured Credit Facility to finance our SCOOP/STACK Acquisitions during the current year. In addition, the weighted average interest rate on our borrowings increased to 8.12% for the fiscal year ended June 30, 2024 compared to 5.25% for fiscal year 2023.

Income tax (expense) provision

For the year ended June 30, 2024, we recognized income tax expense of $1.4 million on net income before income taxes of $5.5 million compared to an income tax expense of $10.1 million on net income before income taxes of $45.3 million for the year ended June 30, 2023. The effective tax rates were 25.8% and 22.2% for the years ended June 30, 2024 and 2023, respectively. The effective tax rate increased compared to the prior year period as projected state income taxes have become a larger component of our overall income tax expense during the period.

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, 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, 2024, 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, 2024 of 10% would affect depletion, depreciation, and amortization expense by approximately $0.5 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 natural gas liquids 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 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 2024 and 2023, 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 SOFR plus 2.80%, which includes a 0.05% credit spread adjustment from LIBOR, subject to a minimum SOFR of 0.50%, or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%. 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

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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, 2024 and 2023, 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, 2024 and 2023, 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of June 30, 2024, based on criteria established in *Internal Control - Integrated Framework* (*2013*) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated September 11, 2024, expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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. 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, 2024, the Company recorded DD&A related to its proved oil and natural gas properties of approximately $18.6 million, and there was no ceiling test impairment.

The Company engages three 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 operating effectiveness of controls over the Company's estimation of oil and natural gas reserve quantities;
    - Testing the data inputs used by specialist for completeness and accuracy;
    - Testing the specialist's 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, 2024, and
        - projected production taxes to recent historical taxes incurred and to statutory tax rates.
- 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/ Moss Adams LLP

Houston, Texas
September 11, 2024

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited Evolution Petroleum Corporation and subsidiaries (the "Company") internal control over financial reporting as of June 30, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2024 and 2023, 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") and our report dated September 11, 2024, expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting included in Item 9A. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Moss Adams LLP

Houston, Texas
September 11, 2024

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, 2024	June 30, 2023
Assets		
Current assets		
Cash and cash equivalents	$ 6,446	$ 11,034
Receivables from crude oil, natural gas, and natural gas liquids revenues	10,826	7,884
Derivative contract assets	596	—
Prepaid expenses and other current assets	3,855	2,277
Total current assets	21,723	21,195
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	139,685	105,781
Other noncurrent assets		
Derivative contract assets	171	—
Other assets	1,298	1,341
Total assets	$ 162,877	$ 128,317
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 8,308	$ 5,891
Accrued liabilities and other	6,239	6,027
Derivative contract liabilities	1,192	—
State and federal taxes payable	74	365
Total current liabilities	15,813	12,283
Long term liabilities		
Senior secured credit facility	39,500	—
Deferred income taxes	6,702	6,803
Asset retirement obligations	19,209	17,012
Derivative contract liabilities	468	—
Operating lease liability	58	125
Total liabilities	81,750	36,223
Commitments and contingencies (Note 10)		
Stockholders' equity		
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 33,339,535 and 33,247,523 shares as of June 30, 2024 and 2023, respectively	33	33
Additional paid-in capital	41,091	40,098
Retained earnings	40,003	51,963
Total stockholders' equity	81,127	92,094
Total liabilities and stockholders' equity	$ 162,877	$ 128,317

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended June 30, 2024	Years Ended June 30, 2023
Revenues		
Crude oil	$ 53,446	$ 51,044
Natural gas	21,525	63,800
Natural gas liquids	10,906	13,670
Total revenues	85,877	128,514
Operating costs		
Lease operating costs	48,273	59,545
Depletion, depreciation, and accretion	20,062	14,273
General and administrative expenses	9,636	9,583
Total operating costs	77,971	83,401
Income (loss) from operations	7,906	45,113
Other income (expense)		
Net gain (loss) on derivative contracts	(1,292)	513
Interest and other income	342	121
Interest expense	(1,459)	(458)
Income (loss) before income taxes	5,497	45,289
Income tax (expense) benefit	(1,417)	(10,072)
Net income (loss)	$ 4,080	$ 35,217
Net income (loss) per common share:		
Basic	$ 0.12	$ 1.05
Diluted	$ 0.12	$ 1.04
Weighted average number of common shares outstanding:		
Basic	32,691	32,985
Diluted	32,901	33,190

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended June 30, 2024	Years Ended June 30, 2023
Cash flows from operating activities:		
Net income (loss)	$ 4,080	$ 35,217
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, and accretion	20,062	14,273
Stock-based compensation	2,137	1,639
Settlement of asset retirement obligations	(20)	(174)
Deferred income taxes	(101)	(296)
Unrealized (gain) loss on derivative contracts	893	(1,994)
Accrued settlements on derivative contracts	67	(919)
Other	—	(4)
Changes in operating assets and liabilities:		
Receivables from crude oil, natural gas, and natural gas liquids revenues	(2,910)	18,441
Prepaid expenses and other current assets	(1,562)	(692)
Accounts payable and accrued liabilities and other	374	(13,489)
State and federal taxes payable	(291)	(730)
Net cash provided by operating activities	22,729	51,272
Cash flows from investing activities:		
Acquisition of oil and natural gas properties	(38,734)	(31)
Capital expenditures for oil and natural gas properties	(10,899)	(6,961)
Net cash used in investing activities	(49,633)	(6,992)
Cash flows from financing activities:		
Common stock dividends paid	(16,040)	(16,106)
Common stock repurchases, including stock surrendered for tax withholding	(1,144)	(4,170)
Borrowings under senior secured credit facility	42,500	—
Repayments of senior secured credit facility	(3,000)	(21,250)
Net cash provided by (used in) financing activities	22,316	(41,526)
Net increase (decrease) in cash and cash equivalents	(4,588)	2,754
Cash and cash equivalents, beginning of period	11,034	8,280
Cash and cash equivalents, end of period	$ 6,446	$ 11,034
Supplemental disclosures of cash flow information:		
Cash paid for interest on senior secured credit facility	$ 1,331	$ 498
Cash paid for income taxes	2,804	11,876
Non-cash investing and financing transactions:		
Increase (decrease) in accrued capital expenditures for oil and natural gas properties	$ (1,969)	$ 766
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	887	2,015

See accompanying notes to consolidated financial statements.

EVOLUTION PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value				
Balances at June 30, 2022	33,471	$ 33	$ 42,629	$ 32,852	$ —	$ 75,514
Issuance of restricted common stock	476	1	(1)	—	—	—
Forfeitures of restricted stock	(26)	—	—	—	—	—
Common stock repurchases, including stock surrendered for tax withholding	—	—	—	—	(4,170)	(4,170)
Retirements of treasury stock	(673)	(1)	(4,169)	—	4,170	—
Stock-based compensation	—	—	1,639	—	—	1,639
Net income (loss)	—	—	—	35,217	—	35,217
Common stock dividends paid	—	—	—	(16,106)	—	(16,106)
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

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 oilfield 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 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; 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. To conform with the current year presentation, $0.6 million of accrued ad valorem and productions taxes at June 30, 2023 are included with "*Accrued taxes other than federal and state income tax*" instead of "*Accrued payables*" as disclosed in Note 13, "*Additional Financial Information.*" This reclassification has no impact on previously reported net income or stockholders' equity.

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 a limited ability to influence the operation or future development of such properties. However, the Company is proactive with its third-party operators to review capital projects and related spending and present alternative plans as appropriate.

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 natural gas liquids ("NGL") revenues and 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.

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, 2024 and 2023, 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 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, 2024 and 2023, the Company did not have any costs excluded from 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, 2024 and 2023 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, 2024, four individual purchasers, 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. In the year ended June 30, 2023, three individual purchasers, Diversified, Denbury, and Conoco Phillips, each accounted for more than 10% of the Company's total revenues, collectively representing approximately 65% 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 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

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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 is currently evaluating ASU 2023-07 and the impact it may have to the Company’s financial position, results of operations, cash flow or disclosures.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments - Credit Losses* (“ASU 2016-13”). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires the use of a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. Early adoption is permitted and entities must adopt the amendment using a modified retrospective approach to the first reporting period in which the guidance is effective. For smaller reporting companies, as provided by ASU 2019-10, *Financial Instruments - Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842)*, ASU 2016-13 is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2022. The Company adopted ASU 2016-13 effective July 1, 2023. The adoption did not have a material effect on the Company’s financial position, results of operations, cash flows 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 oilfield 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; and the Delhi Field in Northeast Louisiana. 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, 2024 and 2023 (in thousands):

	Years Ended June 30, 2024	2023
Revenues		
Crude oil	$ 53,446	$ 51,044
Natural gas	21,525	63,800
Natural gas liquids	10,906	13,670
Total revenues	$ 85,877	$ 128,514

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. 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

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 taking into account customary closing adjustments and an effective date of November 1, 2023, total combined cash consideration for the SCOOP/STACK Acquisitions was approximately $39.2 million, which includes $43.9 million paid at closing less purchase price adjustments totaling approximately $4.7 million related to net cash flows received on the properties subsequent to closing. The Company accounted for these transactions as asset acquisitions and allocated all of 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 253 producing wells in the SCOOP and STACK plays of the Anadarko Basin in Oklahoma.

Chaveroo Oilfield 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 oilfield, located in Chaves and Roosevelt Counties, New Mexico. In accordance with the Participation Agreement, the Company will have 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, 2024, the Company incurred approximately $0.8 million in exchange for a 50% working interest share in the existing leases associated with five development blocks. As of June 30, 2024, the Company has participated in the drilling and completion of the first development block, consisting of three gross wells (1.5 net wells).

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.

Note 4. Property and Equipment

Property and equipment as of June 30, 2024 and 2023 consisted of the following (in thousands):

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

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, 2024 and 2023, all oil and natural gas property costs were subject to amortization. Depletion on oil and natural gas properties was $18.6 million and $13.1 million for the years ended June 30, 2024 and 2023, respectively. During the years ended June 30, 2024 and 2023, the Company incurred development capital expenditures of $12.3 million and $6.2 million, respectively.

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 West Texas Intermediate ("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 differentials to WTI 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.

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At June 30, 2023, 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, 2023 of the WTI crude oil spot price of $83.23 per barrel and Henry Hub natural gas spot price of $4.78 per MMBtu, adjusted by market differentials by field. The net price per barrel of NGLs was $33.71, which was based on historical differentials to WTI as NGLs do not have any single comparable reference index price. Using these prices at June 30, 2023, 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 three-year, senior secured reserve-based credit facility, as amended, (the "Senior Secured Credit Facility") with MidFirst Bank in an amount up to $50.0 million with a current borrowing base of $50.0 million. On May 5, 2023, the Company entered into the Tenth Amendment to the Senior Secured Credit Facility extending the maturity to April 9, 2026. The Tenth Amendment also replaced the London Interbank Offered Rate ("LIBOR") with the Secured Overnight Financing Rate ("SOFR") plus a credit spread adjustment of 0.05% to effectively convert SOFR to a LIBOR equivalent and modifies the Margined Collateral Value, as defined in the Ninth Amendment to the Senior Secured Credit Facility, to $95.0 million. 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 SOFR plus 2.80%, which includes a 0.05% credit spread adjustment from LIBOR, subject to a minimum SOFR of 0.50%, or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%.

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 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 or 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. As of June 30, 2024, the Company had $39.5 million in borrowings outstanding under its Senior Secured Credit Facility, resulting in $10.5 million of available borrowing capacity. For the years ended June 30, 2024 and 2023, the weighted average interest rate on borrowings under the Senior Secured Credit Facility was 8.12% and 5.25%, respectively. As of June 30, 2024, the Company was in compliance with all covenants under the Senior Secured Credit Facility.

On February 12, 2024, the Company entered into an amendment to the Senior Secured Credit Facility. This amendment required that the Company enter into hedges for the next 12-month period, and on a rolling 12-month basis thereafter, covering expected crude oil and natural gas production from proved developed reserves, calculated separately, equal to a minimum of 40% of expected crude oil production each month, or 25% of expected crude oil and natural gas production each month over that period. The Company has the option to choose whether to hedge 40% of expected crude oil production or 25% of expected crude oil and natural gas production.

On February 7, 2022, the Company entered into the Ninth Amendment to the Senior Secured Credit Facility. This amendment, among other things, modified the definition of utilization percentage related to the required hedging covenant such that for the purposes of determining the amount of future production to hedge, the utilization of the Senior Secured Credit Facility will be based on the Margined Collateral Value, as defined in the agreement, to the extent it exceeds the borrowing base then in effect. This amendment also required the Company to enter into hedges for the next 12-month period ending February 2023, covering 25% of expected crude oil and natural gas production over that period.

On November 9, 2021, the Company entered into the Eighth Amendment to the Senior Secured Credit Facility. This amendment, among other things, increased the borrowing base to $50.0 million and added a hedging covenant whereby the Company must hedge a minimum of 25% to 75% of future production on a rolling 12-month basis when 25% or more of the borrowing base is utilized. The hedging covenant was amended in subsequent amendments, as discussed above.

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.

There were no unrecognized tax benefits, nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2024 and 2023. 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, 2020 through June 30, 2023 for federal tax purposes and for the fiscal years ended June 30, 2019 through June 30, 2023 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, 2024 and 2023 is comprised of the following (in thousands):

	June 30, 2024	June 30, 2023
Current:		
Federal	$ (898)	$ (9,600)
State	(620)	(768)
Total current income tax (expense) benefit	(1,518)	(10,368)
Deferred:		
Federal	59	457
State	42	(161)
Total deferred income tax (expense) benefit	101	296
Total income tax (expense) benefit	$ (1,417)	$ (10,072)

For the year ended June 30, 2024 the Company recognized income tax expense of $1.4 million and had an effective tax rate of 25.8% compared to income tax expense of $10.1 million and an effective tax rates of 22.2% for the year ended June 30, 2023. During the years ended June 30, 2024 and 2023, the Company recognized an income tax benefit of less than $0.1 million and $0.1 million, respectively, related to the vesting of restricted stock awards.

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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, and Texas, due to percentage depletion in excess of basis, and other permanent differences. 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, 2024	% of Income Before Income Taxes	June 30, 2023	% of Income Before Income Taxes
Income tax (expense) benefit computed at the statutory federal rate:	$ (1,154)	21.0 %	$ (9,511)	21.0 %
Reconciling items:				
Return to provision adjustments	3	(0.1)%	—	— %
Depletion in excess of tax basis	114	(2.1)%	78	(0.2)%
State income taxes, net of federal tax benefit	(458)	8.4 %	(734)	1.6 %
Permanent differences related to stock-based compensation and other	80	(1.5)%	96	(0.2)%
Other	(2)	0.1 %	(1)	— %
Income tax (expense) benefit	$ (1,417)	25.8 %	$ (10,072)	22.2 %

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, 2024	June 30, 2023
Deferred tax assets:		
Non-qualified stock-based compensation	$ 381	$ 250
Net operating loss carry-forwards and other carry-forwards	313	—
Derivative losses	192	—
Asset retirement obligations	4,427	3,883
Other deferred tax assets	197	201
Total deferred tax assets	5,510	4,334
Deferred tax liabilities:		
Oil and natural gas properties	(12,072)	(11,137)
Total deferred tax liabilities	(12,072)	(11,137)
Valuation allowance	(140)	—
Net deferred tax liabilities	$ (6,702)	$ (6,803)

Evolution Petroleum OK, Inc., a wholly-owned subsidiary of the Company, has a prior year carryforward of NOLs of $8.9 million generated during tax years 2011 through 2017. With the current year acquisition of assets in Oklahoma by Evolution Petroleum OK, Inc., a deferred tax asset was recorded for a portion of this NOL carryforward.

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.

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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, 2024, 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 and/or fixed-price swaps to hedge a portion of its anticipated future production. A 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. 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. 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, 2024 and 2023 (in thousands):

Derivatives not designated as hedging contracts under ASC 815	Balance sheet location	Derivative Contract Assets June 30, 2024	Derivative Contract Assets June 30, 2023	Balance sheet location	Derivative Contract Liabilities June 30, 2024	Derivative Contract Liabilities June 30, 2023
Commodity contracts	Current assets - derivative contract assets	$ 596	$ —	Current liabilities - derivative contract liabilities	$ 1,192	$ —
Commodity contracts	Other assets - derivative contract assets	171	—	Long term liabilities - derivative contract liabilities	468	—
Total derivatives not designated as hedging contracts under ASC 815		$ 767	$ —		$ 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, 2024 and 2023 (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, 2024	Years Ended June 30, 2023
Commodity contracts:			
Realized gain (loss) on derivative contracts	Other income and expenses - net gain (loss) on derivative contracts	$ (399)	$ (1,481)
Unrealized gain (loss) on derivative contracts	Other income and expenses - net gain (loss) on derivative contracts	(893)	1,994
Total net gain (loss) on derivative contracts		$ (1,292)	$ 513

As of June 30, 2024, the Company had the following open crude oil and natural gas derivative contracts:

Period	Instrument	Commodity	Volumes in MMBTU/BBL	Weighted Average Swap Price per MMBTU/BBL	Weighted Average Floor Price per MMBTU/BBL	Weighted Average Ceiling Price per MMBTU/BBL
July 2024 - December 2024	Fixed-Price Swap	Crude Oil	73,558	$ 74.20		
July 2024 - December 2024	Collar	Crude Oil	73,558		$ 70.00	$ 77.40
January 2025 - March 2025	Collar	Crude Oil	42,566		68.00	73.77
January 2025 - February 2025	Fixed-Price Swap	Natural Gas	312,286	3.56		
April 2025 - June 2025	Collar	Crude Oil	41,601		65.00	84.00
March 2025 - December 2026	Fixed-Price Swap	Natural Gas	3,170,705	3.60		

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, 2024 and 2023 (in thousands):

	Derivative Contract Assets		Derivative Contract Liabilities	
Offsetting of Derivative Assets and Liabilities	June 30, 2024	June 30, 2023	June 30, 2024	June 30, 2023
Gross amounts presented in the Consolidated Balance Sheet	$ 767	$ —	$ 1,660	$ —
Amounts not offset in the Consolidated Balance Sheet	(497)	—	(497)	—
Net amount	$ 270	$ —	$ 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

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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 judgment, 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. 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, 2024 (in thousands). The Company did not have any open positions as of June 30, 2023.

	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, 2024 and 2023 (in thousands):

	June 30, 2024	June 30, 2023
Asset retirement obligations — beginning of period	$ 17,067	$ 13,921
Liabilities incurred	28	57
Liabilities settled	(39)	(136)
Liabilities acquired(1)	90	—
Accretion of discount	1,457	1,131
Revisions of previous estimates(2)	808	2,094
Asset retirement obligations — end of period	19,411	17,067
Less: current asset retirement obligations	(202)	(55)
Long-term portion of asset retirement obligations	$ 19,209	$ 17,012

(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, 2024 and 2023.

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, 2024, the Company had 33,339,535 shares of common stock outstanding.

The Company began paying quarterly cash dividends on common stock in December 2013. As of June 30, 2024, the Company has cumulatively paid over $118.4 million in cash dividends. The Company paid dividends of $16.0 million and $16.1 million to its common stockholders during the years ended June 30, 2024 and 2023, respectively. The following table reflects the dividends paid per share within the respective quarterly periods:

	Fiscal Year	
	2024	2023
Fourth quarter ended June 30,	$ 0.12	$ 0.12
Third quarter ended March 31,	0.12	0.12
Second quarter ended December 31,	0.12	0.12
First quarter ended September 30,	0.12	0.12

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On September 9, 2024, Evolution's Board of Directors approved and declared a quarterly dividend of $0.12 per common share payable September 30, 2024. Refer to Note 14, *"Subsequent Events,"* for a further discussion.

On September 8, 2022, the Board of Directors approved a share repurchase program, under which the Company is authorized to repurchase up to $25.0 million of its common stock in the open market through December 31, 2024. The Company intends to fund repurchases from working capital and cash provided by operating activities. The Board of Directors along with the management team believe that a share repurchase program is complimentary to the existing dividend policy and is a tax efficient means to further improve shareholder return. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will depend on a variety of factors, including management's assessment of the intrinsic value of the Company's shares, the market price of the Company's common stock, the Company's capital needs and resources, general market and economic conditions, and applicable legal requirements. The value of shares authorized for repurchase by the Company's Board of Directors does not require the Company to repurchase such shares or guarantee that such shares will be repurchased, and the program may be suspended, modified, or discontinued at any time without prior notice. As of June 30, 2024, a total of 0.8 million shares of the Company's common stock have been repurchased under the plan at a total cost of approximately $4.6 million, including incremental direct transaction costs.

In December 2022, 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 included a 30-day cooling off period that did not allow repurchases to commence until January 2023. The plan was effective until June 30, 2023 and had a maximum authorized amount of $5.0 million over that period. During the year ended June 30, 2023, 0.6 million shares of the Company's common stock were repurchased under the plan at a total cost of approximately $3.9 million, including incremental direct transaction costs. These treasury shares were subsequently cancelled.

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, 2024 and 2023, 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, 2024 and 2023 (in thousands, except per share amounts):

	Years Ended June 30,	
	2024	**2023**
Number of treasury shares acquired[(1)]	202	673
Average cost per share[(1)]	$ 5.66	$ 6.20
Total cost of treasury shares acquired	$ 1,144	$ 4,170

[(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. For the year ended June 30, 2023, includes 633,789 shares repurchased under the Company's share repurchase program for a weighted average price of $6.07 per share.

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Expected Tax Treatment of Dividends

For the fiscal year ended June 30, 2023, 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, 2024, 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. Incentives under the 2016 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 and non-statutory stock options, stock appreciation rights, restricted stock awards and restricted stock unit awards, performance share awards, performance cash awards, and other forms of incentives valued in whole or in part by reference to, or otherwise based on, the Company’s common stock, including its appreciation in value. As of June 30, 2024 and 2023, approximately 0.9 million shares and 1.3 million shares, respectively, remained available for grant under the 2016 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, 2024, and 2023, the Company recognized $2.1 million and $1.6 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, the intrinsic value indexed solely to its common stock or the intrinsic value indexed to its 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 four 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 four years from the date of grant if unvested. Shares underlying performance-based contingent share units are reserved from the 2016 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 and/or the Company’s absolute total stock return. For certain awards, this Monte Carlo simulation also provides an expected vesting term. 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

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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 or, in some cases, vest when the average of the Company's closing common stock price over a defined measurement period meets or exceeds a required common stock price.

For performance-based awards granted during the years ended June 30, 2024 and 2023, the assumptions used in the Monte Carlo simulation valuations were as follows:

	Years Ended June 30,	
	2024	2023
Weighted average fair value of performance-based awards granted	$ 3.58	$ 6.52
Risk-free interest rate	4.87%	3.91% to 4.51%
Expected term in years	2.77	2.36 to 2.78
Expected volatility	55.0%	56.5% to 70.9%
Dividend yield	7.4%	6.1% to 7.8%

Unvested restricted stock awards as of June 30, 2024 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Time-vested awards	395,104	$ 6.57
Performance-based awards	233,407	5.87
Unvested at June 30, 2024	628,511	$ 6.31

The following table sets forth the restricted stock award transactions for the years ended June 30, 2024 and 2023:

	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, 2022	341,211	$ 4.54			
Time-vested shares granted	376,015	7.18			
Performance-based shares granted	100,239	7.39			
Vested	(196,431)	4.91			
Forfeited	(25,620)	6.51			
Unvested at June 30, 2023	595,414	$ 6.48	$ 2,827	2.4	$ 4,805
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

(1) *The intrinsic value of restricted stock was calculated as the closing market price on June 30, 2024 and 2023 of the underlying stock multiplied by the number of restricted shares that would be issuable. The total fair value of shares vested was $1.6 million and $1.4 million for the years ended June 30, 2024 and 2023, respectively.*

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The following table sets forth contingent restricted stock unit transactions for the years ended June 30, 2024 and 2023:

	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, 2022	50,062	$ 2.21			
Performance-based awards granted	50,123	4.79			
Forfeited	(3,787)	3.69			
Unvested at June 30, 2023	96,398	$ 3.49	$ 195	1.9	$ 778
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

(1) *The intrinsic value of contingent restricted stock units was calculated as the closing market price on June 30, 2024 and 2023 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, 2024	Years Ended June 30, 2023
Numerator		
Net income (loss)	$ 4,080	$ 35,217
Undistributed earnings allocated to unvested restricted stock	(83)	(560)
Net income (loss) for earnings per share calculation	$ 3,997	$ 34,657
Denominator		
Weighted average number of common shares outstanding — Basic	32,691	32,985
Effect of dilutive securities:		
Unvested restricted stock awards	183	193
Unvested contingent restricted stock units	27	12
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share	32,901	33,190
Net income (loss) per common share — Basic	$ 0.12	$ 1.05
Net income (loss) per common share — Diluted	$ 0.12	$ 1.04

Unvested restricted stock awards (both time-vested and performance-based), totaling approximately 0.1 million for each of the years ended June 30, 2024 and 2023, 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.

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Note 13. Additional Financial Statement Information

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

	June 30, 2024	June 30, 2023
Prepaid expenses and other current assets:		
Other receivables	$ 19	$ 18
Prepaid insurance	734	727
Prepaid federal and state income taxes	1,798	805
Carryback of EOR tax credit	347	347
Advances to operators	608	—
Prepaid other	349	380
Total prepaid expenses and other current assets	$ 3,855	$ 2,277
Other assets:		
Deposit(1)	$ 1,158	$ 1,158
Right of use asset under operating lease	140	183
Total other assets	$ 1,298	$ 1,341
Accrued liabilities and other:		
Accrued payables	$ 2,570	$ 3,005
Accrued capital expenditures	860	167
Accrued incentive and other compensation	945	941
Accrued royalties payable(2)	307	977
Accrued taxes other than federal and state income tax	1,062	739
Accrued severance	—	81
Accrued settlements on derivative contracts	67	—
Operating lease liability	98	59
Asset retirement obligations due within one year	202	55
Accrued interest and other	128	3
Total accrued liabilities and other	$ 6,239	$ 6,027

(1) The deposit of $1.2 million is related to a long-term gas gathering deposit with Enterprise entered into at closing of the Company's Jonah Field properties.

(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

On September 9, 2024, the Company declared a quarterly cash dividend of $0.12 per share of common stock to shareholders of record on September 20, 2024 and payable on September 30, 2024.

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, 2024	June 30, 2023	June 30, 2022
Oil and natural gas properties			
Property costs subject to amortization	$ 249,559	$ 197,049	$ 188,634
Less: Accumulated depletion, depreciation, and impairment	(109,874)	(91,268)	(78,126)
Oil and natural gas properties, net	$ 139,685	$ 105,781	$ 110,508

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 $0.9 million, $2.0 million, and $7.8 million during the years ended June 30, 2024, 2023, and 2022, respectively.

	For the Years Ended June 30,		
	2024	2023	2022
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$ 39,153	$ 31	$ 49,920
Unproved property	—	—	—
Exploration costs	—	—	—
Development costs	13,357	8,384	9,591
Total costs incurred for oil and natural gas activities	$ 52,510	$ 8,415	$ 59,511

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, Netherland, Sewell & Associates, Inc. ("NSAI"), DeGolyer & MacNaughton ("D&M"), and Cawley, Gillespie and Associates, Inc. ("CG&A"). Reserve volumes and values were determined under the method prescribed by the SEC for the fiscal years ended June 30, 2024, 2023 and 2022. 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 NSAI is Matthew D. Pankey, P.E., Petroleum Engineer. Mr. Pankey, a licensed Professional Engineer in the State of Texas (No. 142931), has been practicing consulting petroleum engineering at NSAI since 2019 and has over six years of prior industry experience. Mr. Pankey received a Bachelor of Science degree in Chemical Engineering in 2012 from Auburn University. 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 14 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). 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.

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, 2021	8,420	48,571	6,871	23,386
Revisions of previous estimates	(1,111)	25,268	(944)	2,157
Improved recovery, extensions and discoveries	2,608	2,197	623	3,597
Purchase of reserves in place	2,172	38,096	755	9,276
Production (sales volumes)	(619)	(7,141)	(364)	(2,173)
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

	MBOE		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Proved developed and undeveloped reserves:			
June 30, 2021	21,573	1,813	23,386
Revisions of previous estimates	3,970	(1,813)	2,157
Improved recovery, extensions and discoveries	—	3,597	3,597
Purchase of reserves in place	9,276	—	9,276
Production (sales volumes)	(2,173)	—	(2,173)
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

For the fiscal year ended June 30, 2024, notable change 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.

For the fiscal year ended June 30, 2022, notable changes in total proved reserves included the following:

- *Purchase of reserves in place*. During the fiscal year ended 2022, the Company completed the acquisitions of its Williston Basin and the Jonah Field properties totaling $26.4 million and $25.2 million, respectively.
- *Improved recovery, extensions and discoveries*. During the fiscal year 2022, the Company added 3.6 MBOE of PUD reserves associated with drilling locations at its Willison Basin properties.
- *Revisions of previous estimates.* Net Revisions in fiscal year 2022 totaled 2.2 MMBOE, which included a net positive revision in the Company's proved developed reserves of 4.0 MMBOE offset by the removal of 1.8 MMBOE of PUD reserves at the Delhi Field, related to Test Site V. At this time, the operator at Delhi does not currently have Test Site V on its expenditure schedule for the next five years and, as a result, has been excluded from the Company's PUD reserves. The net positive revision in the Company's proved developed reserves of 4.0 MMBOE includes positive revisions totaling 4.7 MMBOE primarily related to the improvement in the SEC

trailing 12-month pricing offset by a 0.7 MMBOE downward adjustment at Delhi due to lower than anticipated production during fiscal year 2022.

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, 2024, 2023 and 2022 are as follows (in thousands):

	For the Years Ended June 30,		
	2024	**2023**	**2022**
Future cash inflows	$ 1,250,176	$ 1,521,363	$ 1,846,708
Future production costs and severance taxes	(748,927)	(860,054)	(997,362)
Future development costs	(139,628)	(120,648)	(105,966)
Future income tax expenses	(61,742)	(109,189)	(159,912)
Future net cash flows	299,879	431,472	583,468
10% annual discount for estimated timing of cash flows	(133,278)	(193,295)	(268,685)
Standardized measure of discounted future net cash flows	$ 166,601	$ 238,177	$ 314,783

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:	**2024**	**2023**	**2022**
Oil (Bbl)	$ 79.45	$ 83.23	$ 85.82
Gas (MMBtu)	2.32	4.78	5.19

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,		
	2024	**2023**	**2022**
Balance, beginning of year	$ 238,177	$ 314,783	$ 87,583
Net changes in sales prices and production costs related to future production	(125,539)	(31,923)	171,602
Changes in estimated future development costs	1,081	(8,286)	(6,320)
Sales of oil, natural gas and NGLs produced, net of production costs	(37,604)	(68,969)	(60,269)
Net change due to extensions, discoveries, and improved recovery	52,014	4,695	43,495
Net change due to revisions in quantity estimates	(47,244)	(34,056)	48,177
Net change due to purchase of minerals in place	37,139	—	100,675
Development costs incurred during the period	933	—	—
Accretion of discount	30,121	40,382	14,425
Net change in discounted income taxes	26,743	26,006	(65,559)
Other	(9,220)	(4,455)	(19,026)
Balance, end of year	$ 166,601	$ 238,177	$ 314,783

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, 2024.

The effectiveness of the Company's internal controls over financial reporting as of June 30, 2024, has been audited by Moss Adams LLP., an independent registered public accounting firm, as stated in their report.

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, 2024 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 2024 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 2024 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 2024 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 2024 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 2024 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 on Consolidated Financial Statements
   Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
   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)
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	Credit Agreement dated April 11, 2016 between Evolution Petroleum Corporation and MidFirst Bank (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed April 15, 2016)
10.2.1	First Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective October 18, 2016 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed November 9, 2016)
10.2.2	Second Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective February 1, 2018 (incorporated by reference to exhibit 10.1 of our Quarterly Report on Form 10-Q filed February 8, 2018)
10.2.3	Third Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective May 25, 2018 (incorporated by reference to Exhibit 10.10 of our Annual Report on Form 10-K filed September 10, 2018)
10.2.4	Fourth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective December 31, 2018 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed February 8, 2019)
10.2.5	Fifth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective November 2, 2020 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed November 9, 2020)

EXHIBIT NUMBER	DESCRIPTION
10.2.6	Sixth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective December 28, 2020 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on January 11, 2021)
10.2.7	Seventh Amendment to Credit Agreement dated August 5, 2021, between Evolution Petroleum Corporation and MidFirst Bank effective June 30, 2021 (incorporated by reference to Exhibit 10.8 of our Quarterly Report on Form 10-Q filed May 12, 2022)
10.2.8	Eighth Amendment to Credit Agreement dated November 9, 2021, between Evolution Petroleum Corporation and MidFirst Bank effective November 9, 2021 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed November 10, 2021)
10.2.9	Ninth Amendment to the Credit Agreement dated February 7, 2022, between Evolution Petroleum Corporation and MidFirst Bank effective February 4, 2022 (incorporated by reference to Exhibit 10.9 of our Quarterly Report on Form 10-Q filed May 12, 2022)
10.2.10	Tenth Amendment to the Credit Agreement dated May 5, 2023, between Evolution Petroleum Corporation and MidFirst Bank (incorporated by reference to Exhibit 10.2.10 of our Quarterly Report on Form 10-Q filed May 10, 2023)
10.2.11	Amendment to the Credit Agreement dated February 12, 2024 between Evolution Petroleum Corporation and MidFirst Bank (incorporated by reference to Exhibit 10.2.11 of our Quarterly Report on Form 10-Q filed May 8, 2024)
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)
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)

EXHIBIT NUMBER	DESCRIPTION
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)
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)
21.1*	List of Subsidiaries of Evolution Petroleum Corporation
23.1*	Consent of Moss Adams LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of DeGolyer & MacNaughton
23.4*	Consent of Cawley, Gillespie and Associates, Inc.
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 Netherland, Sewell & Associates, Inc.'s Report as of June 30, 2024, on oil and gas reserves (SEC Case) dated August 13, 2024
99.2*	The summary of DeGolyer and MacNaughton's Report as of June 30, 2024, on oil and gas reserves (SEC Case) dated August 14, 2024
99.3*	The summary of Cawley, Gillespie and Associates, Inc.'s Report as of June 30 ,2024, on oil and gas reserves (SEC Case) dated July 31, 2024
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
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 11, 2024

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 11, 2024	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 11, 2024	/s/ KELLY W. LOYD Kelly W. Loyd	President and Chief Executive Officer (Principal Executive Officer) and Director
September 11, 2024	/s/ RYAN STASH Ryan Stash	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
September 11, 2024	/s/ KELLY M. BEATTY Kelly M. Beatty	Chief Accounting Officer (Principal Accounting Officer)
September 11, 2024	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 11, 2024	/s/ MYRA C. BIERRIA Myra C. Bierria	Director
September 11, 2024	/s/ WILLIAM DOZIER William Dozier	Director
September 11, 2024	/s/ MARJORIE A. HARGRAVE Marjorie A. Hargrave	Director

Exhibit 21.1

List of Subsidiaries of Evolution Petroleum Corporation

Name of Subsidiary	Jurisdiction of Incorporation or Organization
Evolution Royalties, Inc.	Delaware
Evolution Petroleum West, Inc.	Delaware
NGS Sub Corp.	Delaware
NGS Technologies, Inc.	Delaware
Evolution Operating Co., Inc.	Texas
Evolution Petroleum OK, Inc.	Texas
Tertiaire Resources Company	Texas
ARKLA Petroleum, LLC (Subsidiary of NGS Sub. Corp.)	Louisiana
NGS Resources, LLC (Subsidiary of NGS Technologies, Inc.)	Texas
EPM Chaveroo, LLC.	New Mexico

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-193899), Forms S-3/A (No. 333-265430 and 333-231412), and Forms S-8 (No. 333-251233, 333-152136, 333-140182, 333-183746 and 333-216098) of Evolution Petroleum Corporation (the “Company”), of our report dated September 11, 2024, relating to the consolidated financial statements of the Company which report expresses an unqualified opinion, appearing in this Annual Report on Form 10-K of the Company for the year ended June 30, 2024.

/s/ Moss Adams LLP

Houston, Texas
September 11, 2024

NETHERLAND, SEWELL & ASSOCIATES, INC.

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves report dated August 13, 2024, included in the Annual Report on Form 10-K of Evolution Petroleum Corporation (the "Company") for the fiscal year ended June 30, 2024, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves reports into the Registration Statements on Form S-3/A Nos. 333-265430 and 333-231412, Form S-3 No. 333-193899, Form S-8 Nos. 333-251233, 333-152136, 333-140182, 333-183746, and 333-216098.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

Houston, Texas
September 11, 2024

EXHIBIT 23.3

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

September 11, 2024

Evolution Petroleum Corporation
1155 Dairy Ashford Road, Suite 425
Houston, Texas 77079

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our report of third party dated August 14, 2024, and to the inclusion of information taken from our report entitled "Report as of June 30, 2024 on Reserves and Revenue of Certain Properties with interests attributable to Evolution Petroleum Corporation" in the Annual Report on Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2024. We further consent to the incorporation by reference of information in the Form 10-K in the Evolution Petroleum Corporation Registration Statements on Form S-8 (File Nos. 333-251233, 333-152136, 333-140182, 333-183746, and 333-216098), Form S-3/A (File Nos. 333-265430 and 333-231412), and Form S-3 (File No. 333-193899).

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

6500 RIVER PLACE BLVD, SUITE 3-200
AUSTIN, TEXAS 78730-1111
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our reserves report dated July 31, 2024, included in the Annual Report on Form 10-K of Evolution Petroleum Corporation (the "Company") for the fiscal year ended June 30, 2024, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves reports into the Registration Statements on Form S-3/A Nos. 333-265430 and 333-231412, Form S-3 No. 333-193899, Form S-8 Nos. 333-251233, 333-152136, 333-140182, 333-183746, and 333-216098.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

By: /s/ W. Todd Brooker
W. Todd Brooker, P.E.
President

Austin, Texas
September 11, 2024

EXHIBIT 31.1

CERTIFICATION

I, Kelly W. Loyd, President and Chief Executive Officer (Principal Executive Officer) and Director, of Evolution Petroleum Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;

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

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

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

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

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

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

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

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

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

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

Dated: September 11, 2024

/s/ KELLY W. LOYD

Kelly W. Loyd
President and Chief Executive Officer (Principal Executive Officer) and Director

EXHIBIT 31.2

CERTIFICATION

I, Ryan Stash, Senior Vice President, Chief Financial Officer (Principal Financial Officer) and Treasurer of Evolution Petroleum Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;

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

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

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

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

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

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

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

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

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

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

Dated: September 11, 2024

/s/ RYAN STASH
Ryan Stash
Senior Vice President, Chief Financial Officer (Principal Financial Officer) and Treasurer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, Kelly W. Loyd, President and Chief Executive Officer (Principal Executive Officer) and Director of Evolution Petroleum Corporation (the “Company”), certifies in connection with the filing with the Securities and Exchange Commission of the Company’s Annual Report on Form 10-K for the year ended June 30, 2024 (the “Report”) pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

IN WITNESS WHEREOF, the undersigned has executed this certification as of September 11, 2024.

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

A signed original of this written statement require d by Section 906 has been provided to Evolution Petroleum Corporation and will be retained by Evolution Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certificate is being furnished to the Securities and Exchange Commission as an exhibit to this Form 10-K and shall not be considered filed as part of the Form 10-K.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, Ryan Stash, Senior Vice President, Chief Financial Officer (Principal Financial Officer) and Treasurer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2024 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

IN WITNESS WHEREOF, the undersigned has executed this certification as of September 11, 2024.

/s/ RYAN STASH
Ryan Stash
Senior Vice President, Chief Financial Officer (Principal Financial Officer) and Treasurer

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A signed original of this written statement required by Section 906 has been provided to Evolution Petroleum Corporation and will be retained by Evolution Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certificate is being furnished to the Securities and Exchange Commission as an exhibit to this Form 10-K and shall not be considered filed as part of the Form 10-K.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

August 13, 2024

Mr. Kelly W. Loyd
Evolution Petroleum Corporation
1155 Dairy Ashford Street, Suite 425
Houston, Texas 77079

Dear Mr. Loyd:

In accordance with your request, we have estimated the proved reserves and future revenue, as of June 30, 2024, to the Evolution Petroleum Corporation (Evolution) interest in certain oil and gas properties located in North Dakota, Oklahoma, and Wyoming, referred to herein as the Anadarko Basin, Jonah Field, and Williston Basin Assets. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 46 percent of all proved reserves owned by Evolution. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Evolution's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Evolution interest in the Anadarko Basin, Jonah Field, and Williston Basin Assets, as of June 30, 2024, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	2,358.6	998.1	33,830.2	119,525.1	79,502.6
Proved Developed Non-Producing	108.1	8.5	33.2	1,737.8	709.0
Proved Undeveloped	1,847.3	1,751.7	10,698.8	48,454.2	17,682.1
Total Proved	4,314.0	2,758.3	44,562.2	169,717.1	97,893.8

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Evolution's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Evolution's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

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1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period July 2023 through June 2024. For oil and NGL volumes, the average West Texas Intermediate spot price of $79.45 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.32 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $75.96 per barrel of oil, $22.10 per barrel of NGL, and $2.74 per MCF of gas.

Operating costs used in this report are based on operating expense records of Evolution. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Evolution and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Evolution's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Evolution interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Evolution receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Evolution, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Evolution, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Matthew D. Pankey, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2019 and has over 6 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr

Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ Matthew D. Pankey

Matthew D. Pankey, P.E. 142931
Petroleum Engineer

Date Signed: August 13, 2024

MDP:ALA

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

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

EXHIBIT 99.2

August 14, 2024

Evolution Petroleum Corporation
1155 Dairy Ashford Rd., Suite 425
Houston, Texas 77079

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of June 30, 2024, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of the Delhi field in Louisiana, the net proved developed producing condensate, NGL, and gas reserves of the Barnett Shale in Texas, and the net proved developed producing oil reserves of the Hamilton Dome field in Wyoming in which Evolution Petroleum Corporation and its subsidiaries (collectively referred to herein as Evolution) have represented they hold an interest. The properties evaluated herein consist of working and royalty interests. This evaluation was completed on August 14, 2024. Evolution has represented that these properties account for 46.6 percent on a net equivalent barrel basis of Evolution's net proved reserves as of June 30, 2024. The net proved reserves estimates have been prepared in accordance with the reserves definitions of
Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with the guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Evolution.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after June 30, 2024. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Evolution after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, carbon dioxide purchase expenses, transportation and processing expenses, compression charges, and overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Evolution to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with abandonment. At the request of Evolution, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a discount rate of 10 percent per year compounded at mid-year on an annual basis over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

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

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

Definition of Reserves

Petroleum reserves included in this report are classified by degree of proof as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *Proved oil and gas reserves* – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> (i) The area of the reservoir considered as proved includes:
> (A) The area identified by drilling and limited by fluid contacts, if any, and
> (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
>
> (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
>
> (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
> (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definition of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Evolution, and analysis of areas offsetting existing wells with test or production data, reserves were classified as proved.

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Evolution.

Evolution has represented that its senior management is committed to the development plan provided by Evolution and that Evolution has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. Certain properties evaluated herein are produced using enhanced oil recovery methods involving continuous carbon dioxide flooding operations. Therefore, carbon dioxide versus oil ratios and carbon dioxide injection volumes were analyzed and projected and were used in the estimation of reserves when applicable.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

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

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

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Data provided by Evolution from wells drilled through June 30, 2024, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through February 29, 2024. Estimated cumulative production, as of

June 30, 2024, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 4 months.

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

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

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

Primary Economic Assumptions

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

Oil, Condensate, and NGL Prices

> Evolution has represented that the oil, condensate, and NGL prices were based on a reference 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,

unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Evolution to the West Texas Intermediate (WTI) reference price of $79.45 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $73.31 per barrel of oil and condensate and $25.19 per barrel of NGL.

Gas Prices

Evolution has represented that the gas prices were based on a reference 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, unless prices are defined by contractual agreements. Evolution supplied differentials to the Henry Hub gas reference price of $2.32 per million Btu. The prices were held constant thereafter. Btu factors were provided by Evolution and used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.441 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using rates provided by Evolution, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Evolution based on recent payments.

Evolution has represented that the Delhi carbon dioxide flood has been qualified as a tertiary recovery project and that no oil production taxes will be charged until certain investment and interest expenses have been paid out from the project revenue. Oil production taxes then revert to a 12.5-percent rate, which rate is held constant until average oil production per well drops below 25 barrels per day, and then reduced to 6.25 percent thereafter. Payout is not expected to occur prior to depletion, so no oil production taxes are included herein for the Delhi field.

Operating Expenses, Capital Costs, and Abandonment Costs

> Estimates of operating expenses, provided by Evolution and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using values from the 12 months prior to the as-of date of this report, provided by Evolution, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Evolution and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

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

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

Summary of Conclusions

DeGolyer and MacNaughton has performed an independent evaluation of the extent and value of the estimated net proved oil, condensate, NGL, and gas reserves of certain properties in which Evolution has represented it holds an interest.

The estimated net proved reserves, as of June 30, 2024, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Estimated by DeGolyer and MacNaughton Net Reserves as of June 30, 2024		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved Developed	5,128	4,048	32,712
Proved Undeveloped	151	45	0
Total Proved	**5,279**	**4,093**	**32,712**

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of June 30, 2024, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$) (M$)	**Undeveloped (M$) (M$)**	**Total Proved (M$)**
Future Gross Revenue	556,890	13,049	569,939
Production Taxes	10,910	17	10,927
Ad Valorem Taxes	16,921	131	17,052
Operating Expenses	402,864	2,816	405,680
Capital Costs	3,712	1,290	5,002
Abandonment Costs	24,906	143	25,049
Future Net Revenue	97,577	8,652	106,229
Present Worth at 10 Percent	61,734	4,022	65,756

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

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the June 30, 2024, estimated reserves.

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

Submitted,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Dilhan Ilk
Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton

[Seal]

CERTIFICATE of QUALIFICATION

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

1. That I am an Executive Vice President with DeGolyer and MacNaughton, which firm did prepare this report of third party addressed to Evolution dated August 14, 2024, and that I, as Executive Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 14 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dilhan Ilk

Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton

[Seal]

EXHIBIT 99.3

July 31, 2024

Mr. J. Mark Bunch, PE
Chief Operating Officer
Evolution Petroleum Corporation
1155 Dairy Ashford Road, Suite 425
Houston, TX 77077

Re: Evaluation Summary
Evolution Petroleum Corporation
Certain Properties in Chaves County, New Mexico
Total Proved Reserves
As of June 30, 2024

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Mr. Bunch:

As requested, this report was completed on July 31, 2024 for Evolution Petroleum Corporation ("Evolution"), for the purpose of public disclosure by Evolution in filings made with the *Securities and Exchange Commission* ("SEC") in accordance with the disclosure requirements set forth in the SEC regulations. We evaluated 100% of the Chaves County, New Mexico proved reserves, as per information from Evolution. This evaluation utilized an effective date of June 30, 2024, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the SEC. The results of this evaluation are presented below:

		Proved Developed Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves					
Oil	- Mbbl	259.3	259.3	1,958.2	2,217.5
Gas	- MMcf	85.4	85.4	550.6	636.0
NGL	- Mbbl	19.6	19.6	117.4	137.0
Net Revenue					
Oil	- M$	19,402.7	19,402.7	146,511.3	165,914.0
Gas	- M$	95.5	95.5	616.1	711.7
NGL	- M$	277.3	277.3	2,390.3	2,667.6
Severance Taxes	- M$	1,618.0	1,618.0	12,232.3	13,850.3
Ad Valorem Taxes	- M$	3.6	3.6	27.5	31.1
Future Production Costs	- M$	3,772.0	3,772.0	30,311.3	34,083.3
Future Development Costs	- M$	465.0	465.0	35,190.0	35,655.0
Net Operating Income (BFIT)	- M$	13,916.9	13,916.9	71,756.7	85,673.6
Discounted @ 10%	**- M$**	**8,935.4**	**8,935.4**	**30,305.8**	**39,241.2**

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow (net operating income) is after deducting these taxes, future development costs, and future production costs, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten (10) percent to determine its "present worth". The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties by Cawley, Gillespie & Associates, Inc. (CG&A).

The oil reserves include oil and condensate. Oil and natural gas liquid (NGL) volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base. Our estimates are for proved reserves only and do not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated.

Proved Developed reserves are equivalent to the Proved Developed Producing reserve estimates. Proved Developed reserves were estimated at 259.3 Mbbl oil, 85.4 MMcf gas and 19.6 Mbbl NGLs (or 293.2 MBOE). BOE (barrels of oil equivalent) is expressed as oil and NGL volumes in barrels plus gas volumes in Mcf divided by six (6) to convert to barrels.

Hydrocarbon Pricing

The base SEC oil and gas prices calculated for June 30, 2024 were $79.45 per barrel and $2.319 per MMBTU, respectively. As specified by the SEC, a company must use a 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. The SEC base oil price is based upon WTI-Cushing spot prices (EIA) and the SEC base gas price is based upon Henry Hub spot prices (EIA) from July 2023 through June 2024. Furthermore, NGL prices were adjusted on a field level basis and averaged 26.0% of the proved net oil price on a composite basis.

The base prices were adjusted for differentials on a field level basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices over the life of the proved properties were estimated to be $74.820 per barrel for oil, $1.119 per MCF for gas, and $19.466 per barrel for NGLs. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, future production costs (lease operating expenses) and future development costs (capital investments) were calculated and prepared by Evolution and were audited by us using historical expense data. Our audit determined that the commercial parameters being applied were reasonable and appropriate, and therefore no changes were made to cost parameters. All economic parameters, including future production costs and investments, were held constant (not escalated) throughout the life of these properties in accordance with SEC guidelines.

Future production costs shown in the summary table on page one (1) of this letter includes standard operating expenses (fixed) as well as "other deductions" which are variable operating expenses tied to production volumes.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC, as outlined in the definitions immediately following this letter. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes, and royalties currently in effect except as noted herein. Evolution's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

This evaluation includes 18 PUD locations, each being a commercial horizontal well opportunity targeting the San Andres reservoir in Chaves County, New Mexico. Each of the PUD drilling locations proposed as part of Evolution's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, Evolution has indicated they have every intent to complete this development plan as scheduled. Furthermore, Evolution has demonstrated that they have the proper company staffing, financial backing and prior development success to ensure this development plan will be fully executed.

Reserves Estimation Methods

Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for undeveloped properties, were forecast using either production performance, volumetric or analogy methods, or a combination of each. These methods provide a relatively high degree of accuracy for predicting proved undeveloped reserves for the Evolution properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

General Discussion

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third-party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have been included in this evaluation.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. This evaluation was supervised by W. Todd Brooker, President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or Evolution Petroleum Corporation and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Yours very truly,

CAWLEY, GILLESPIE & ASSOCIATES, INC.
TEXAS REGISTERED ENGINEERING FIRM F-693

By: /s/ W. Todd Brooker
W. Todd Brooker, P. E.
President

By: /s/ Thomas M. Barr
Thomas M. Barr
Sr. Reservoir Engineer

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **Proved oil and gas reserves**. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations— prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"(i) The area of a reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

"(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

"(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"(6) **Developed oil and gas reserves.** Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

"(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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

"(31) **Undeveloped oil and gas reserves.** Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

"(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

"(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **Probable reserves.** Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

"(17) **<u>Possible reserves</u>.** Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

"(26) **<u>Reserves</u>.** Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Note to paragraph (26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."