UNIT CORPORATION

A Delaware Corporation

8200 South Unit Drive
Tulsa, OK 74132

Telephone: (918) 493-7700
Email: ir@unitcorp.com

Federal EIN: 73-1283193
NAICS: 211120, 211130, 213111

Issuer's Annual Report
For the annual period ended December 31, 2025
(the "Reporting Period")

The number of shares outstanding of our common stock is 9,896,257 as of March 12, 2026.

The number of shares outstanding of our common stock was 9,868,214 as of September 30, 2025 (end of previous reporting period).

Indicate by check mark whether the company is a shell company (as defined in Rule 405 of the Securities Act of 1933 and Rule 12b-2 of the Exchange Act of 1934):

Yes ☐ No ☒

Indicate by check mark whether the company's shell status has changed since the previous reporting period:

Yes ☐ No ☒

Indicate by check mark whether a change in control of the company has occurred over this reporting period:

Yes ☐ No ☒

UNIT CORPORATION

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The following are explanations of some of the industry and general terms we use in this report:

ARO – Asset retirement obligations.

ASC – FASB Accounting Standards Codification.

ASU – Accounting Standards Update.

Bbl – Barrel, or 42 U.S. gallons liquid volume.

Boe – Barrel of oil equivalent. Determined using the ratio of six Mcf of natural gas to one barrel of crude oil or NGLs.

Btu – British thermal unit, used in gas volumes. Btu is used to refer to the natural gas required to raise the temperature of one pound of water by one-degree Fahrenheit at one atmospheric pressure.

Development drilling – The drilling of a well within the proven area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

DD&A – Depreciation, depletion, and amortization.

FASB – Financial and Accounting Standards Board.

FERC – Federal Energy Regulatory Commission.

Finding and development costs – Costs associated with acquiring and developing proved natural gas and oil reserves capitalized under generally accepted accounting principles, including any capitalized general and administrative expenses.

G&A – General and administrative expenses.

Gross acres or gross wells – The total acres or wells in which a working interest is owned.

IF – Inside FERC (U.S. Federal Energy Regulatory Commission).

LOE – Lease operating expense.

MBbls – Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf – Thousand cubic feet of natural gas.

MBoe – Thousand barrels of oil equivalent.

MMBtu – Million Btu's.

MMcf – Million cubic feet of natural gas.

MMcfe – Million cubic feet of natural gas equivalent. It is determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.

Net acres or net wells – The total fractional working interests owned in gross acres or gross wells.

NGLs – Natural gas liquids.

NYMEX – The New York Mercantile Exchange.

OPEC – The Organization of Petroleum Exporting Countries.

Play – A term applied by geologists and geophysicists identifying an area with potential oil and gas reserves.

Producing property – A natural gas or oil property with existing production.
Proved developed reserves – Reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate. For additional information, see the SEC's definition in Rule 4-10(a)(6) of Regulation S-X.

Proved 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 the 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. For additional information, see the SEC's definition in Rule 4-10(a)(22)(i) through (v) of Regulation S-X.

Proved undeveloped reserves – Proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. For additional information, see the SEC's definition in Rule 4-10(a)(431) of Regulation S-X.

Reasonable certainty (regarding reserves) – If deterministic methods are used, reasonable certainty means high 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.

Reliable technology – 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.

Ryder Scott – Ryder Scott Company, L.P., independent petroleum consultants.

SEC – Securities and Exchange Commission.

SOFR – Secured Overnight Financing Rate.

Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to the point that would permit the production of economic quantities of natural gas or oil regardless of whether the acreage contains proved reserves.

The following are explanations of some of the terms we use that are specific to us:

BOKF – Bank of Oklahoma Financial Corporation.

Chapter 11 Cases – The cases filed by the Debtors on May 22, 2020 under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. The Chapter 11 proceedings were jointly administered under the caption In re Unit Corporation, et al. Case No. 20-32740 (DRJ). During the pendency of the Chapter 11 Cases, the Debtors operated their business as "debtors-in-possession" under the authority of the bankruptcy court and under the Bankruptcy Code. The Debtors emerged from bankruptcy on September 3, 2020.

Debtors – Unit and its wholly owned subsidiaries Unit Drilling Company, Unit Petroleum Company, 8200 Unit, Unit Drilling Colombia, and Unit Drilling USA, all of which were parties to the Chapter 11 Cases.

Emergence Date – September 3, 2020, the date the Debtors emerged from bankruptcy.

Exit Credit Agreement – The credit agreement the Company entered into on September 3, 2020 with the lenders.

New Common Stock – The Company common stock at a par value of $0.01 issued under the Plan and following the Emergence Date.

Plan – The Chapter 11 plan of reorganization (including all exhibits and schedules, as amended, supplemented, or modified) and the related disclosure statement we filed with the bankruptcy court on June 9, 2020.

Old Common Stock – The Company's common stock existing immediately before the Company filed for bankruptcy protection. As part of the Plan, the Old Common Stock was terminated as of the Emergence Date.

Second Amended and Restated Credit Agreement – The credit agreement the Company entered into on March 8, 2024 with the lenders.

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENTS

This report contains "forward-looking statements" related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended (Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). All statements, other than statements of historical facts, included or incorporated by reference in this document addressing activities, events, or developments we expect or anticipate will or may occur, are forward-looking statements. The words "believes," "may," "intends," "expects," "anticipates," "projects," "estimates," "predicts," and similar expressions are used to identify forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties, and assumptions. Future actions, conditions or events, and future results may differ materially from those expressed in our forward-looking statements. Many factors that will determine these results are beyond our ability to control or accurately predict. Specific factors that could cause actual results to differ from those in our forward-looking statements include:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- our business strategy;
- our production of oil, NGLs, and natural gas;
- our ability to utilize the benefits of net operating losses and other deferred tax assets against potential future taxable income;
- expansion and growth of our business and operations;
- our belief that the outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- the impact of federal and state legislative and regulatory actions affecting our costs and increasing operating restrictions or delays and other adverse impacts on our business;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against or otherwise affecting our facilities and systems;
- any projected production guidelines we may issue;
- our anticipated capital budgets;
- our financial condition and liquidity;
- the number of wells we plan to drill; and
- our estimates of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

These statements are based on our assumptions and analyses considering our experience and our perception of historical trends, current conditions, expected future developments, and other factors we believe are appropriate in the circumstances. Whether actual results and developments will meet our expectations and predictions is subject to risks and uncertainties, any one or combination of which could cause our actual results to differ materially from our expectations and predictions. Some of these risks and uncertainties are:

- the risk factors discussed in this document and the documents (if any) we incorporate by reference;
- general economic, market, or business conditions, including inflation, tariffs, and interest rates;
- the availability and nature of (or lack of) business opportunities we pursue;
- changes in laws and regulations;
- changes in the current geopolitical situation;
- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- the amount and terms of our debt;
- future compliance with covenants under our credit agreements;
- our ability to pay dividends and make share repurchases;
- pandemics, epidemics, outbreaks, or other public health events; and
- other factors, most of which are beyond our control.

You should not construe this list to be exhaustive and additional discussion of factors that may affect our forward-looking statements appear elsewhere in this report. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that the actions, events, or results expressed in forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements. Except as required by law, we disclaim any obligation to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after this document to reflect incorrect assumptions or unanticipated events.

UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2025

Part A. General Company Information

The name of the issuer is Unit Corporation. Unless otherwise indicated or required by the context, the terms “Company,” “Unit,” “us,” “our,” “we,” and “its” refer to Unit Corporation or, as appropriate, its wholly-owned subsidiary, Unit Petroleum Company (UPC). Unit was founded in 1963 as an oil and natural gas contract drilling company and has grown to include operations in exploration and production. Unit Corporation is the name of both the successor entity that emerged from bankruptcy on September 3, 2020 and the predecessor entity prior to emergence. Unit is actively conducting operations as a Delaware corporation and is not a "shell company" as defined in the OTCQX U.S. Disclosure Guidelines and the federal securities laws.

Our executive offices are located at 8200 South Unit Drive, Tulsa, Oklahoma 74132; our telephone number is (918) 493-7700. Our company website is at www.unitcorp.com and our investor relations contact is Rene Punch, Investor Relations via mail or telephone as listed above or via email at ir@unitcorp.com.

Part B. Share Structure

Common Stock

Stockholders of the Company are entitled to dividends if declared by the Board of Directors. Each share of our common stock entitles the holder thereof to one vote on all matters submitted to a vote of the stockholders. Our common stock has certain stockholder consent rights related to, among other things, the nature of the Company’s business, liquidation and dissolution, and tax treatment. Holders of common stock do not have preemptive rights, or rights to convert their common stock into other securities.

The provisions of Unit Corporation’s articles of incorporation and bylaws that are summarized below may have an antitakeover effect and may delay, defer or prevent a tender offer or takeover attempt that a stockholder might consider to be in such stockholder's best interests, including those attempts that might result in a premium over the market price for the shares held by stockholders:

- the requirement that only stockholders owning at least 25% of the outstanding shares of our common stock may call a special stockholders’ meeting; and
- our Board of Directors is classified in two groups, each serving staggered two-year terms.

Under our certificate of incorporation, we may issue shares of preferred stock on terms that are unfavorable to the holders of our common stock. The issuance of shares of preferred stock could also prevent or inhibit a third party from acquiring us. The existence of these provisions could depress the price of our common stock, could delay or prevent a takeover attempt or could prevent attempts to replace or remove incumbent management.

Our common stock was issued at a par value of $0.01 and trades on the OTCQX Best Market under the symbol "UNTC" (CUSIP Number: 909218406).

Warrants

Each holder of Unit common stock outstanding (Old Common Stock) before the Emergence Date that did not opt out of the release under the Plan was entitled to receive 0.03460447 warrants for every share of Old Common Stock owned. Each warrant is exercisable for one share of common stock, subject to adjustment as provided in the Warrant Agreement. The warrants expire on the earliest of (i) September 3, 2027, (ii) consummation of a Cash Sale (as defined in the Warrant Agreement), or (iii) the consummation of a liquidation, dissolution or winding up of the Company.

As of December 31, 2025, the Company had authorized 1,843,318 warrants of which 100,668 had been exercised or canceled.

Among other provisions, the Warrant Agreement outlines potential adjustments to the warrants if certain events occur, including (i) stock dividends payable in shares of common stock or stock splits, (ii) reverse stock splits or similar combination events, (iii) Liquidity Events (as defined in the Warrant Agreement), and (iv) other events not explicitly contemplated which may have an adverse impact to the intent and purpose of the warrants as set forth in the Plan, provided, however, the warrants will not be adjusted for (a) any issuances of securities in connection with a merger, share exchange, asset acquisition, stock purchase, recapitalization, reorganization or other similar business combination, (b) the issuance of any securities by Unit on or after Emergence Date pursuant to the Plan or upon the issuance of shares of common stock upon the exercise of such securities, (c) the issuance of any shares of common stock pursuant to the exercise of the warrants, (d) the issuance of shares of common stock pursuant to any management stock option incentive or similar plan, (e) a dividend or distribution to holders of common stock of cash, property, or securities (other than common stock), and/or (f) any change in the par value of the common stock. See Note 19 – Commitments and Contingencies for litigation related to the warrants.

Pursuant to the terms of the Warrant Agreement, the Company determined the initial exercise price of the warrants to be $63.74. On April 7, 2022, the Company delivered notice of the initial exercise price to the Warrant Agent and the warrants became exercisable for shares of the Company's common stock. On or about April 25, 2022, the warrants began trading over-the-counter under the symbol "UNTCW" (CUSIP Number: 909218125). On March 31, 2023, the warrants began trading on the OTCQX Best Market.

The table below presents information about the securities authorized for issuance as of the dates indicated:

	As of December 31,	
	2025	2024
Common Stock:		
Number of shares authorized	25,000,000	25,000,000
Number of shares outstanding	9,895,773	9,747,725
Number of shares freely tradable (public float) [(1)(2)]	9,614,667	9,580,049
Total number of holders of record [(3)]	15	16
Preferred Stock:		
Number of shares authorized	1,000,000	1,000,000
Number of shares outstanding	—	—
Number of shares freely tradable (public float)	—	—
Total number of holders of record	—	—
Warrants:		
Number of shares authorized	1,843,318	1,843,318
Number of shares outstanding	1,721,563	1,721,563
Number of shares freely tradeable (public float)	—	—
Total number of holders of record	—	—

1. The number of shares freely tradable includes shares held by Prescott Group Capital Management LLC and may include shares held by other stockholders owning 10% or more of our common stock. These stockholders may be considered "affiliates" within the meaning of Rule 144, and their shares may be "control shares" subject to the volume and manner of sale restrictions under Rule 144.
2. The number of shares freely tradable excludes shares of our common stock held by our officers and directors as well as shares issued on the exercise of options that had not yet reached the required holding period. These shares may be "control shares" and "restricted shares," respectively, subject to the volume and manner of sale restrictions under Rule 144.
3. The majority of common stock shares are held in street name.

Transfer Agent

Equiniti Trust Company, LLC
28 Liberty Street, Floor 53
New York, New York 10005
Phone: (718) 921-8200

Equiniti Trust Company, LLC (formerly American Stock Transfer and Trust Company, LLC) is registered under the Exchange Act. EQ's procedures and transactions are regulated and audited by the SEC.

Part C. Business Information

As a result of the sale of wholly-owned contract drilling subsidiary, Unit Drilling Company (UDC) on October 1, 2025 and the classification of UDC's results as discontinued operations as discussed below, we now operate, manage, and analyze the results of our operations solely through UPC. UPC develops, acquires, and produces oil and natural gas properties for our own account.

UPC has an interest in 4,713 total wells as of December 31, 2025.

2025 OPERATIONS HIGHLIGHTS

- Revenues increased by 10% from 2024 primarily due to higher price realizations for natural gas.
- Operating costs decreased 4% from 2024 primarily due to lower employee costs in our upstream operations.
- Capital expenditures increased 54% from 2024 as we participated in the completion of 44 gross wells (2.18 net wells) drilled by other operators during the year ended December 31, 2025.

FINANCIAL INFORMATION

General. Our producing oil and natural gas properties, unproved properties, and related assets are primarily located in Oklahoma and Texas. All of our oil and natural gas properties are located in the United States.

The following table presents information regarding our oil and natural gas assets as of December 31, 2025 and production activity during the year then ended:

					2025 Average Net Daily Production		
	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	Natural Gas(Mcf)	Oil(Bbls)	NGLs(Bbls)
Total	4,713	760	7	0.20	34,203	2,222	2,831

Acquisitions and Divestitures. During December 2024, the Company acquired approximately 1,000 acres of oil and gas leases for $3.0 million, of which $0.8 million consideration was paid at closing while $2.2 million was accrued for as of December 31, 2024. In separate transactions, during 2024 the Company also acquired approximately 1,600 acres of oil and gas leases for $4.1 million and made prepayments of $2.5 million on two gross wells. All properties are located in Oklahoma. These amounts are presented in unproved properties not being amortized on the consolidated balance sheets as of December 31, 2024.

In 2025, approximately 1,462 acres of oil and gas leases were developed through new drilling on the leases which were acquired in 2024. The company transferred the leasing costs associated with that acreage to the full cost pool.

Net proceeds for the sale of non-core oil and natural gas assets totaled $3.7 million and $2.9 million during the years ended December 31, 2025 and 2024, respectively. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sales did not result in a significant alteration of the full cost pool.

Well and Leasehold Data. The following table presents the number of oil and natural gas exploratory and development wells completed during the periods indicated:

	Year Ended December 31,			
	2025		2024	
	Gross	Net	Gross	Net
Development:				
Oil	8	0.49	3	0.01
Natural Gas	3	0.01	1	0.00
Dry	—	—	—	—
Total development	11	0.50	4	0.01
Exploratory:				
Oil	28	1.67	6	0.24
Natural gas	5	0.01	11	1.36
Dry	—	—	—	—
Total exploratory	33	1.68	17	1.60
Total wells completed	44	2.18	21	1.61

The following table presents the number of wells producing, capable of producing or shut-in as of the dates indicated:

	As of December 31,			
	2025		2024	
	Gross	Net	Gross	Net
Oil	2,171	166.0	2,136	166.0
Natural gas	2,542	594.0	2,524	610.0
Total	4,713	760.0	4,660	776.0

We did not develop any previously booked proved undeveloped oil and natural gas reserves during the years ended December 31, 2025 or 2024.

The following table presents our leasehold acreage as of December 31, 2025:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net [(1)]	Gross	Net
Total leasehold acreage	390,973	151,648	13,903	1,828	404,876	153,476

1. Approximately 100% of the net undeveloped acres are covered by leases that will expire in the years 2026-2028 unless drilling or production extends those leases.

Price and Production Data. The following tables present the average sales price and production volumes for our oil, NGLs, and natural gas activities during the periods indicated:

	Year Ended December 31,	
	2025	**2024**
Average sales price per barrel of oil produced:		
Price before derivatives	$ 63.40	$ 74.51
Effect of derivatives	0.85	—
Price including derivatives	$ 64.25	$ 74.51
Average sales price per barrel of NGLs produced:		
Price before derivatives	$ 18.64	$ 19.71
Effect of derivatives	—	—
Price including derivatives	$ 18.64	$ 19.71
Average sales price per Mcf of natural gas produced:		
Price before derivatives	$ 2.49	$ 1.58
Effect of derivatives	0.55	—
Price including derivatives	$ 3.04	$ 1.58

	Year Ended December 31,	
	2025	**2024**
Oil production (MBbls):		
Anadarko basin	784	681
All other basins	27	12
Total oil production	811	693
NGLs production (MBbls):		
Anadarko basin	1,018	1,004
All other basins	15	3
Total NGL production	1,033	1,007
Natural gas production (MMcf):		
Anadarko basin	12,393	13,516
All other basins	91	47
Total natural gas production	12,484	13,563
Total production (MBoe):		
Anadarko basin	3,868	3,938
All other basins	57	23
Total BOE production	3,925	3,961

The Anadarko basin contained 96% of our total proved reserves as of December 31, 2025 and 2024 expressed on an oil-equivalent barrel basis. There are no other basins that accounted for more than 10% of our proved reserves.

Oil, NGLs, and Natural Gas Reserves. The table below presents our estimated proved developed and undeveloped oil, NGLs, and natural gas reserves as of December 31, 2025:

	Oil (MBbls)	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total Proved Reserves (MBoe)**
Proved developed	5,364	9,643	104,467	32,418
Proved undeveloped	—	—	—	—
Total proved	5,364	9,643	104,467	32,418

Oil, NGLs, and natural gas reserves cannot be measured exactly. Estimates of those reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in financial disclosures.

Company Reserve Estimation and Technical Qualifications

Our Reservoir Engineering department is responsible for reserve determination for the wells in which we have an interest. Their primary objective is to estimate the wells' future reserves and future net value to us. Data is incorporated from multiple sources including geological, production engineering, marketing, production, land, and accounting departments. The engineers review this information for accuracy as it is incorporated into the reservoir engineering database. Management reviews our internal controls to help provide assurance all the data has been provided. New well reserve estimates are provided to management and the respective operational divisions for additional scrutiny. Major reserve changes on existing wells are reviewed regularly with the operational divisions to confirm completeness and accuracy. As the external audit is being completed, the reservoir department reviews all properties for accuracy of forecasting.

Responsible for overseeing the preparation of our reserve report is our reservoir engineer Derek Smith.

Mr. Smith received a Bachelor of Science in Petroleum Engineering with a Minor in Business from the University of Tulsa in 2005. He then worked for Apache Corporation through 2008 and joined Unit in 2009 as a Corporate Reserves Engineer involved in reserve evaluation, acquisition appraisals, and prospect reviews with increasing levels of responsibility. In 2020, he was promoted to Reservoir Manager. He has been a member of the Society of Petroleum Engineers (SPE) since 2000 and joined the Society of Petroleum Evaluation Engineers (SPEE) in 2018.

As part of his continuing education Mr. Smith has attended various seminars and forums to enhance his understanding of current standards and issues for reserves presentation. These forums have included those sponsored by various professional societies and professional service firms including Ryder Scott.

Ryder Scott Audit and Technical Qualifications

We use Ryder Scott to audit the reserves prepared by our reservoir engineers. Ryder Scott has been providing petroleum consulting services internationally since 1937. Their summary report is attached as Exhibit 99.1 to this Annual Report. The wells or locations for which reserve estimates were audited were taken from our reserve and income projections as of December 31, 2025, and comprised approximately 87% of the total proved developed future net income discounted at 10% (based on the SEC's unescalated pricing policy).

Mr. Robert J. Paradiso was the primary technical person responsible for overseeing the estimate of the reserves prepared by Ryder Scott.

Mr. Paradiso, an employee of Ryder Scott since 2008, is a Vice President and serves as Project Coordinator, responsible for coordinating and supervising staff and consulting engineers in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Paradiso served in several engineering positions with Getty Oil Company, Texaco, Union Texas Petroleum, Amax Oil and Gas, Inc., Norcen Explorer, Inc., Amerac Energy Corporation, Halliburton Energy Services, Santa Fe Snyder Corp., and Devon Energy Corporation.

Mr. Paradiso earned a Bachelor of Science degree in Petroleum Engineering from Texas Tech University in 1979 and is a registered Professional Engineer in the State of Texas. He is also a member of the SPE.

Besides gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires at least fifteen hours of continuing education annually, including at least one hour in professional ethics, which Mr. Paradiso fulfills. Based on his educational background, professional training and over 41 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Paradiso has attained the professional qualifications as a Reserves Estimator and Reserves Auditor in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the SPE as of June 2019. For more information regarding Mr. Paradiso’s geographic and job-specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Company/Employees.

Definitions and Other Proved Reserve Information.

For proved reserves, the area of the reservoir considered as "proved" includes:

- The area identified by drilling and limited by any fluid contacts, and
- Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with the reservoir and to contain economically producible oil or gas based on available geosciences and engineering data.

Absent data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as incurred in a well penetration unless geosciences, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

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

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

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

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average of the prices over the 12 months before the ending date of the period covered by the report and is an unweighted arithmetic average of the first day of the month price for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

Proved Undeveloped Reserves. As of December 31, 2025, we had not recorded any proved undeveloped reserves.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2025 and 2024, the changes in quantities, and standardized measure of those reserves for the years then ended, are shown in the Supplemental Oil and Gas Disclosures in this report.

Contracts. Our oil production is sold at or near our wells under purchase contracts at prevailing prices under arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines and independent marketing firms under contracts with terms generally ranging from one month to a year. Few of these contracts contain provisions for readjustment of price as most are market sensitive.

Customers. Two third-party customers accounted for 31% of our revenues during the year ended December 31, 2025 and no other company accounted for over 10% of our revenues.

COMPETITION

Our business is highly competitive and price sensitive. Many competitors have greater financial, technical, and other resources than we do and have more experience than we do in the exploration for and production of oil and natural gas. Our success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals during times of increased competition as competition for these professionals can be intense.

HUMAN CAPITAL

We believe that our employees are critical to our future success, and seek to provide competitive compensation and benefits to attract and retain a skilled workforce. We care about the well-being and development of our employees and aim to provide a culture of respect and collaboration by supporting employee training and development. We are also very focused on maintaining a culture of continuous improvement in safety and environmental practices as safety and environmental stewardship are at the forefront of everything that we do.

As of December 31, 2025, we had 98 employees, none of whom are members of a union or labor organization. We also periodically utilize the services of independent contractors. We have not experienced any strikes or work-force stoppages.

GOVERNMENTAL REGULATIONS

General. Our business depends on the demand for oil, natural gas, and natural gas liquids. Therefore, our business can be affected by political developments and changes in laws and regulations that control or curtail drilling for oil and natural gas for economic, environmental, or other policy reasons.

Various state and federal regulations affect the production and sale of oil and natural gas. All states in which we conduct activities impose varying restrictions on the drilling, production, transportation, and sale of oil and natural gas. This discussion of certain laws and regulations affecting our operations should not be relied on as an exhaustive review of all regulatory considerations affecting us, due to the multitude of complex federal, state, and local regulations, and their susceptibility to change at any time by later agency actions and court rulings that may affect our operations.

Natural Gas Sales and Transportation. Under the Natural Gas Act of 1938, FERC regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. FERC's authority over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the Decontrol Act) deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. FERC's authority over interstate natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas are affected by intrastate and interstate gas transportation regulation. Beginning in 1985, FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines must divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. Because of the various omnibus rulemaking proceedings in the late 1980s and the later individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users, and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, FERC expanded the impact of open access regulations to certain aspects of intrastate commerce.

FERC has pursued other policy initiatives that affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to using electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information timely and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services on the pipeline's demonstration of lack of market control in the relevant service market.

Because of these changes, independent sellers and buyers of natural gas have gained direct access to the pipeline services they need and can better conduct business with a larger number of counterparties. These changes generally have improved the access to markets for natural gas while substantially increasing competition in the natural gas marketplace. However, we cannot predict what new or different regulations FERC and other regulatory agencies may adopt or what effect later regulations may have on production and marketing of natural gas from our properties.

We may be indirectly exposed to certain risks in the U.S. LNG export markets. The LNG export industry is a highly regulated and capital intensive industry that is subject to a number of risks. Many facilities remain under construction or are expanding, and if these facilities are unable to obtain and maintain approvals and permits from governmental and regulatory agencies, the U.S. LNG market may be materially and adversely impacted, which could reduce demand for U.S. natural gas and have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Oil and Natural Gas Liquids Sales and Transportation. Our sales of oil and natural gas liquids currently are not regulated and are at market prices. The prices received from the sale of these products are affected by the cost of transporting these products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments could cause decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, FERC examines the relationship between the annual change in the index and the actual cost changes experienced by the oil pipeline industry and makes any necessary adjustment in the index to be used during the ensuing five years. We cannot predict with certainty what effect the periodic review of the index by FERC will have on us.

Exploration and Production Activities. Federal, state, and local agencies also have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production, and related operations. The states we operate in require permits for drilling operations, drilling bonds, and filing reports about operations and impose other requirements relating to the exploration of oil and natural gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, and regulating spacing, plugging and, abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are amended or reinterpreted frequently, we cannot predict the future cost or impact of complying with these laws.

Environmental.

General. Our operations are subject to federal, state, and local laws and regulations governing protection of the environment. These laws and regulations may require acquisition of permits before certain of our operations may be commenced and may restrict the types, quantities, and concentrations of various substances that can be released into the environment. Planning and implementation of protective measures must prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids, and other substances may subject us to penalties and cleanup requirements. Handling, storage, and disposal of both hazardous and non-hazardous wastes are subject to regulatory requirements.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act (RCRA), and their state counterparts, are the primary vehicles for imposition of such requirements and for civil, criminal, and administrative penalties and other sanctions for violation of their requirements. In addition, the federal Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons considered responsible for the release of hazardous substances into the environment. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of remedial action and damages to natural resources. The Oil Pollution Act of 1990 amends the Clean Water Act and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, this law requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasure plans.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (EPA) or a state equivalent agency. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The scope of the Clean Water Act's jurisdiction has been the subject of significant uncertainty and litigation in recent years.

To the extent any rule expands the scope of the Clean Water Act's jurisdiction in areas where we operate, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which could delay the development of our natural gas and oil projects. Similarly, any increased costs or delays for such permits may impact the development of pipeline infrastructure, which may impact our ability to transport our products. Also, pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Hazardous Substances and Waste Management. RCRA and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the EPA, individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil, natural gas, and drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future.

CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials during our operations that may be regulated as hazardous substances. Despite the "petroleum exclusion" of CERCLA, which currently encompasses crude oil and natural gas, we may nonetheless generate or handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. Under such laws, we could be required to undertake investigatory, response, or corrective measures, which could include soil and groundwater sampling, the removal of previously disposed substances and wastes, the cleanup of contaminated property, or remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Endangered Species Act. The federal Endangered Species Act (ESA) and analogous state laws regulate many activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the

ESA or their habitats. Designating previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce drilling activities in affected areas. Our business operations could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Numerous species have been listed or are under consideration for protected status under the ESA in areas in which we provide or could undertake operations, such as the dunes sagebrush lizard and greater sage grouse. The presence of protected species in areas where we provide contract drilling or conduct exploration and production operations could impair our ability to timely complete or carry out those services and, consequently, hurt our results of operations and financial position.

Air Emissions. The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain preapproval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The EPA has also adopted rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. The EPA expanded on its emission standards for volatile organic compounds in June 2016 with the issuance of first-time standards to address emissions of methane from equipment and processes across oil and natural gas production, storage, processing and transmission sources, including hydraulically fractured oil natural gas and well completions.

On August 16, 2022, President Biden signed a budget reconciliation measure commonly referred to as the “Inflation Reduction Act of 2022” (IRA). The IRA contains incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and carbon capture and sequestration, among other provisions.

On December 2, 2023, the EPA issued a final rule of pollution reduction standards that address sources of methane and other pollutants at oil and gas facilities, including methane that leaks or is vented from equipment and processes. The final rule will phase in a requirement to eliminate routine flaring of natural gas that is produced by new oil wells, require comprehensive monitoring for leaks of methane from well sites and compressor stations, while giving oil and gas companies flexibility to use low-cost and innovative methane monitoring technologies, and establish standards that require reductions in emissions from high-emitting equipment like controllers, pumps, and storage tanks.

Climate Change. Climate change continues to attract considerable public and scientific attention. As a result, our operations as well as the operations of our operators are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs. At the federal level, no comprehensive climate change law or regulation has been implemented to date. The EPA has, however, adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, and together with the U.S. Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. The federal regulation of methane emissions from oil and gas facilities has been subject to controversy in recent years. For more information, see our regulatory disclosure titled “Air Emissions.”

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards upon GHG emissions from the oil and natural gas sector could result in increased costs of compliance. Concerns related to the impacts of climate change could also result in reduced demand for oil and natural gas and adversely impact the value of reserves. In addition, increased financial scrutiny of climate risks could result in restrictions on our access to capital. Moreover, there are increasing risks to operations resulting from the potential physical impacts of climate change, such as drought, wildfires, damage to infrastructure and resources from flooding, storms, and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

Hydraulic Fracturing. We routinely apply hydraulic fracturing techniques to many of our oil and natural gas properties. Hydraulic fracturing has been the subject of public scrutiny over the past several years. While states typically have primary authority with respect to regulating oil and natural gas production activities, including hydraulic fracturing, from time to time Congress has considered passing new laws to regulate this practice, and the U.S. Government has asserted regulatory authority over certain aspects of hydraulic fracturing. In addition, certain states in which we operate, including Texas and Oklahoma, have adopted, and other states and municipalities and other local governmental entities in some states, have and others are considering adopting regulations and ordinances that could impose more stringent permitting, require the public disclosure of chemicals in fracking fluids, flaring limitations, waste disposal, and well construction requirements on these operations, and even restrict or ban hydraulic fracturing in certain circumstances.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that certain activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. Both the EPA and the United States Geological Survey (USGS) have made statements indicating that the disposal of wastes associated with hydraulic fracturing via injection wells may result in induced seismic events. Several states, including Texas and Oklahoma, have adopted measures limiting disposal well operations in areas under certain circumstances.

At the state level, several states, including Texas, have adopted or are considering legal requirements that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. Local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Any new laws, regulation, or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could delay or limit the drilling services we provide to third parties whose drilling operations could be affected by these regulations or increase our costs of compliance and doing business and delay the development of unconventional gas resources from shale formations which are not commercial without using hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the oil and natural gas we can ultimately produce from our reserves.

Other; Compliance Costs. We cannot predict future legislation or regulations. It is possible that some future laws, regulations, and/or ordinances could increase our compliance costs and/or impose additional operating restrictions on us as well as those of our customers. Such future developments also might curtail the demand for fossil fuels which could hurt the demand for our services, which could hurt our future results of operations. Likewise, we cannot predict with any certainty whether any changes to temperature, storm intensity or precipitation patterns because of climate change (or otherwise) will have a material impact on our operations.

Compliance with applicable environmental requirements has not, to date, had a material effect on the cost of our operations, earnings, or competitive position. However, as noted above in our discussion of the regulation of GHG and hydraulic fracturing, compliance with amended, new, or more stringent requirements of existing environmental regulations or requirements may cause us to incur additional costs or subject us to liabilities that may have a material adverse effect on our results of operations and financial condition.

RISK FACTORS

RISKS CONCERNING COMMODITY PRICES

Our business is heavily affected by commodity prices. Oil, NGLs, and natural gas prices are volatile, and low prices have hurt our financial results and could do so in the future.

Our revenues, operating results, cash flow, and growth depend on prevailing prices for oil, NGLs, and natural gas. Oil, NGLs, and natural gas prices and markets have been volatile, and they are likely to remain volatile.

The prices we receive for our oil, NGLs, and natural gas production affect our revenues, profitability, cash flow, and ability to meet our projected financial and operational goals. Those prices are decided by many factors beyond our control, including:

- the demand for and supply of oil, NGLs, and natural gas;
- weather conditions in the continental United States (which can influence the demand and prices for natural gas);
- the amount and timing of oil, natural gas, and liquefied petroleum gas imports and exports;
- the ability of distribution systems in the United States to effectively meet the demand for oil, NGLs, and natural gas, particularly in times of peak demand which may result because of adverse weather conditions;
- the ability or willingness of OPEC+ to set and support production levels for oil;
- oil and gas production levels by non-OPEC+ countries;
- political and economic uncertainty and geopolitical activity, including military conflicts and perceived hostilities in oil producing regions;
- governmental policies and subsidies;
- the costs of exploring for, producing, and delivering oil and natural gas;
- technological advances affecting energy consumption;
- United States storage levels of oil, NGLs, and natural gas;
- price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream;
- pandemics, epidemics, outbreaks, or other public health events;
- worldwide economic conditions;
- advancement in oil and gas technologies that impact the demand for energy;
- the development and use of alternative energy sources; and
- increased focus by the investment community on alternative energy resources.

Oil prices are sensitive to domestic and foreign influences based on political, social, or economic underpinnings, any of which could have an immediate and significant effect on the price and supply of oil. Prices of oil, NGLs, and natural gas can also be influenced by trading on the commodities markets which has increased the volatility associated with these prices, causing large differences in prices on even a weekly and monthly basis.

Based on our production for the year ended December 31, 2025, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $0.1 million per month ($1.3 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of derivatives, would result in a $0.1 million per month ($0.7 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs price, without the effect of derivatives, would result in a $0.1 million per month ($1.0 million annualized) change in our pre-tax operating cash flow.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas.

Our derivative arrangements might limit the benefit of increases in oil, NGLs, and/or natural gas prices.

To reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we may use derivative contracts like swaps and collars. Derivative contracts may expose us to risk of financial loss and limit the benefit to us due to changes in market prices. Volumes not covered by derivative contracts are subject to market prices.

See Note 16 - Derivatives for additional information.

If oil, NGLs, and natural gas prices decrease or are unusually volatile, we may have to take write-downs of our oil and natural gas properties.

Each quarter we review the carrying value of our oil and natural gas properties under the SEC's full cost accounting rules. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10% per year. Application of the ceiling test generally requires pricing future revenue at the unweighted arithmetic average of the price on the first day of the month for each month within the 12 months before the end of the reporting period (unless contractual arrangements define the prices) and requires a write-down for accounting purposes if the ceiling is exceeded. We may have to write-down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. A write-down, if required, would cause a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down is not reversible. Because our ceiling tests use a rolling 12-month look back average price, it is possible that a write-down during a reporting period will not remove the need for us to take future write-downs. This could occur when months with higher commodity prices roll off the 12 months and are replaced with more recent months having lower commodity prices.

Our other property and equipment are carried at cost. We must periodically test to see if these values have been impaired whenever events or changes in circumstances suggest the carrying amount may not be recoverable. If these assets are determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of the property, equipment, and related intangible assets. Once these values are reduced, they are not reversible.

RISKS RELATED TO OIL, NGL, AND NATURAL GAS RESERVES

Many uncertainties are inherent in estimating quantities of oil, NGLs, and natural gas reserves and their values, including factors beyond our control. Actual production, revenues, and expenditures regarding our oil, NGLs, and natural gas reserves will likely vary from estimates, and those variances may be material.

Many uncertainties are inherent in estimating quantities of oil, NGLs, and natural gas reserves and their values, including factors beyond our control. The oil, NGLs, and natural gas reserve information in this report is only an estimate of these reserves. Oil, NGLs, and natural gas reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured precisely. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on several variable factors, including historical production from the area compared with production from other producing areas, and assumptions about: reservoir size; the effects of regulations by governmental agencies; future oil, NGLs, and natural gas prices; future operating costs; severance and excise taxes; operational risks; development costs; and workover and remedial costs.

Some or all these assumptions may vary considerably from actual results. For these and other reasons, estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any group of properties, classifications of those oil, NGLs, and natural gas reserves based on the risk of recovery, and estimates of the future net cash flows from oil, NGLs, and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Oil, NGLs, and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues, and expenditures regarding our oil, NGLs, and natural gas reserves will likely vary from estimates, and those variances may be material.

The information about discounted future net cash flows in this report is not necessarily the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. Using full cost accounting requires us to use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues unless prices were otherwise determined under contractual arrangements. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected by these factors:

- the amount and timing of oil, NGLs, and natural gas production;
- supply and demand for oil, NGLs, and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

Although we are not a reporting company under the Exchange Act, we use the 10% discount factor required by the SEC for calculating discounted future net cash flows for reporting purposes, which is not necessarily the most accurate discount factor based on interest rates in effect from time to time and the risks associated with our operations or the oil and natural gas industry.

Estimated quantities of oil, NGLs, and natural gas reserves and their values used to prepare our consolidated financial statements and supplemental oil and gas disclosures may differ from estimates used in other strategic or economic purposes.

As described above, the information about discounted future net cash flows in this report is not necessarily the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties so estimates used by management for strategic or economic purposes may differ.

RISKS RELATED TO FINANCING OUR BUSINESS

Our inability to satisfy our future debt obligations and covenants could result in our failure to meet our capital needs and adversely affect our operations.

We may incur substantial capital expenditures in our operations. Historically, we have funded our capital needs through internally generated cash flows. As of December 31, 2025, we had no outstanding borrowings under our credit agreement.

If we borrow under our credit agreement, the cash flow needed to satisfy that debt and the covenants in our bank credit agreements could:

- limit funds otherwise available for financing our capital expenditures, our drilling program, or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;
- place us at a competitive disadvantage to those of our competitors less indebted than we are;
- make us more vulnerable during periods of low oil, NGLs, and natural gas prices or if a downturn in our business occurs; and
- prevent us from obtaining more financing on acceptable terms or limit amounts available under our existing or future credit facilities.

Our ability to meet any future debt obligations depends on our future performance. If such obligations are not satisfied, a default could be deemed to occur, and our lenders could accelerate the payment of the outstanding indebtedness. See "Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict" below.

Restrictive covenants in our credit facilities may limit our financial and operating flexibility and our ability to pursue our business strategies.

As of December 31, 2025, we had no outstanding borrowings under our credit agreement. Our financing agreement permits us to incur more indebtedness and other obligations. We may also seek amendments or waivers from our existing lender if we need to incur indebtedness above amounts permitted by our financing agreement.

Our credit facility contains certain restrictions, which may have adverse effects on our business, financial condition, cash flows or results of operations, limiting our ability, among other things, to:

- incur additional indebtedness;
- incur additional liens;
- make investments, loans, or advances;
- sell or discount receivables;
- enter into mergers;
- sell properties;
- enter into or terminate swap agreements;
- enter into transactions with affiliates;
- maintain gas imbalances;
- enter into take-or-pay contracts or make other prepayments;
- enter into sale and leaseback agreements;
- amend our organizational documents; and
- make capital expenditures.

The credit facility also requires us to comply with certain financial maintenance covenants as discussed elsewhere in this report.

A breach of any of these restrictive covenants could cause a default. If a default occurs, the lender(s) under our credit facility may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due. The lender(s) would also have the right in that case to terminate any commitments they have to provide more borrowings. If we cannot repay our indebtedness when due or declared due, the lender(s) may also proceed against the collateral pledged to secure the indebtedness. If the indebtedness was accelerated, our assets might not fully repay our secured indebtedness.

Disruptions in the financial markets could affect our ability to obtain financing or refinance existing indebtedness on reasonable terms and may have other adverse effects.

Commercial-credit and equity market disruptions may cause tight capital markets in the United States. Liquidity in the global capital markets can be severely contracted by market disruptions making financing less attractive. In some cases, it leads to the unavailability of certain types of financing. Because of credit and equity market turmoil, we may not obtain debt or equity financing or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Dividends and share repurchases are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including the Company’s financial results, cash requirements, and future prospects, as well as other factors deemed relevant by our Board of Directors. We can provide no assurance that we will continue to pay dividends at the current rate or at all or authorize share repurchases. Any elimination of, or reduction to, our dividend payout or share repurchase program could have an adverse effect on the market price of our common stock.

RISKS RELATED TO OPERATING OUR BUSINESS

Increasing attention to environmental, social and governance (ESG) matters may adversely impact our business.

Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to evaluate their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and to the diversion of their investment away from the fossil fuel industry to other industries which could have a negative impact on our stock price and our access to and costs of capital.

Public health events outside our control, including pandemics, epidemics, and infectious disease outbreaks may materially hurt our business.

We face risks related to epidemics, pandemics, outbreaks, or other public health events outside our control that could disrupt our operations and hurt our financial condition. It is difficult to predict the timing, frequency or severity of such events or how such frequency or severity may change. Any such events could have a material adverse effect on our results of operations or financial condition.

The industry in which we operate is highly competitive, and many of our competitors have resources more significant than we do.

The oil and natural gas industry is highly competitive. We compete in property acquisitions and oil and natural gas exploration, development, production, and marketing with major oil companies, other independent oil and natural gas concerns, and individual producers and operators. Many of our competitors in the oil and natural gas industry have resources substantially greater than we do.

Competition for experienced technical personnel may hurt our operations or financial results.

Our success will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other employees. Competition for these employees can be intense, particularly when the industry is experiencing favorable conditions.

Our operations are subject to inherent risks that, if material, could harm our results of operations.

Our exploration and development operations involve many risks that may cause dry holes, the failure to produce oil, NGLs, and natural gas in commercial quantities, and the inability to fully produce discovered reserves. The cost of drilling, completing, and operating wells is substantial and uncertain. Many of these factors are beyond our control and may cause the curtailment, delay, or cancellation of drilling operations.

Exploratory drilling is a speculative activity. Success rates may decline. Also, we may not lease or drill the drilling prospects we have identified or budgeted for. Lack of drilling success will hurt our future results of operations and financial condition. We do not operate many of the wells in which we own an interest. Our operational risks for those wells and our ability to influence those wells' operations are less subject to our control and the operators of those wells may act in ways not in our best interests.

Our prospective drilling locations are in various evaluation stages, ranging from a prospect ready to drill to a prospect that will require additional geological and engineering analysis. Based on many factors, including future oil, NGLs, natural gas prices, the generation of additional seismic or geological information, and other factors, we may decide not to drill one or more of these prospects. We may not increase or maintain our reserves or production, which could hurt our business, financial position, and operating results. Although we are not a reporting company under the Exchange Act, we still comply with the SEC's reserve reporting rules requiring that, subject to limited exceptions, proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of booking. At December 31, 2025, we had no proved undeveloped drilling locations.

New technologies may cause our exploration and drilling methods to become obsolete, causing an adverse effect on our production.

Our industry is subject to rapid and significant technological advancements, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may allow them to implement new technologies before we can. We cannot be sure that we can implement technologies timely or at an acceptable cost. One or more technologies we use or that we may implement may become obsolete or may not work as we expected, and we may be hurt financially and operationally as a result.

Our operating results depend on our ability to transport oil, NGLs, and gas production to key markets.

The marketability of our oil, NGLs, and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems, refineries, and other transportation sources. The unavailability of or lack of capacity on these systems and facilities could cause the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal and state regulation of oil, NGLs, and natural gas production and transportation, tax, and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could hurt our ability to produce, gather, and, transport oil, NGLs, and natural gas.

Losing one or several of our larger customers could have a material adverse effect on our financial condition and results of operations.

During the year ended December 31, 2025, two customers accounted for 31% of our revenues. No other third-party customer accounted for 10% or more of any of our revenues. Any customer may choose not to purchase oil, natural gas, or NGLs from us, and losing one or several of our larger customers could have a material adverse effect on our financial condition and results of operations if we cannot find replacements.

We rely on management and other key employees.

We depend significantly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We are subject to various claims and litigation that could ultimately be resolved against us, requiring material future cash payments or future material charges against our operating income, and materially impairing our financial position.

The nature of our business makes us highly susceptible to claims and litigation. We are subject to various existing legal claims and lawsuits, which could have a material adverse effect on our consolidated financial position, results of operations, or cash flows. Even if indemnified or insured, any claims or litigation could hurt our reputation among our customers and the public and make it harder for us to compete effectively or obtain adequate insurance in the future.

Climate change legislation or other regulatory initiatives restricting emissions of greenhouse gases (GHGs) could result in increased operating costs and reduced demand for the oil, natural gas and NGLs we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and may continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, mandates for the production of renewable fuels, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, and together with the U.S. Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. For more information, see our regulatory disclosure titled “Air Emissions.”

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards upon GHG emissions from the oil and natural gas sector could result in increased costs of compliance. Concerns related to the impacts of climate change could also result in reduced demand for oil and natural gas and adversely impact the value of reserves. In addition, increased financial scrutiny of climate risks could result in restrictions on our access to capital. Moreover, there are increasing risks to operations resulting from the potential physical impacts of climate change, such as drought, wildfires, damage to infrastructure and resources from flooding, storms, and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Geopolitical tensions may create market volatility or other disruptions which could negatively impact our ability to carry out our business plan.

Although we have no direct transactional or supply chain exposure to current areas of conflict, related geopolitical and economic responses could significantly impact the global financial markets and supply chains, or cause other disruptions which could negatively impact our business plan and operations.

Ineffective internal controls could affect the accuracy and timely reporting of our business and financial results.

Our internal controls over financial reporting (ICFR) may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Even effective internal controls can provide only reasonable assurance about the preparation and fair presentation of financial statements. If we do not maintain our internal controls' adequacy, including any failure to implement needed new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed, and we could fail to meet our financial reporting obligations.

RISKS TO OUR POTENTIAL GROWTH PLANS

Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict.

Any growth plans may require significant cash. Our principal sources of liquidity include the cash flows generated from operations and available borrowing capacity. If our cash flows from operations decrease, we may be unable to expend the capital to maintain our operations, hurting our future revenues. Our liquidity, including our ability to meet our ongoing operational obligations, depends on, among other things: (i) our ability to comply with the terms of our credit facility, (ii) our ability to maintain adequate cash on hand, and (iii) our ability to generate cash flow from operations.

Growth through acquisitions is not assured.

The exploration and development industry have experienced significant consolidation over the past several years. There is no assurance that acquisition opportunities will be available or viable. Even if available, there is no assurance we would have the financial ability to pursue the opportunity. We expect the competition for acquisition opportunities to persist or intensify.

We may incur substantial indebtedness to finance future acquisitions and may issue debt instruments, equity securities, or convertible securities in connection with any acquisitions. Debt service requirements could represent a significant burden on our operations and financial condition and issuing more equity would be dilutive to existing shareholders. Growth from mergers or acquisitions could strain our management, operations, employees, and other resources.

Successful acquisitions, particularly those of oil and natural gas companies or oil and natural gas properties, require assessing several factors, many of which are beyond our control. These factors include recoverable reserves, exploration potential, future oil, NGLs, and natural gas prices, operating costs, and potential environmental and other liabilities. Such assessments are inexact, and their accuracy is inherently uncertain.

Our future performance may depend on our ability to find or acquire more oil, NGLs, and natural gas reserves that are economically recoverable.

Production from oil and natural gas properties declines as reserves are depleted, with a well's decline rate depending on reservoir characteristics. Unless we replace the reserves we produce, our reserves will decline, resulting in a decrease in oil, NGLs, and natural gas production and lower revenues and cash flow. Historically, we have increased reserves after considering our production through exploration and development. We have conducted these activities on our existing oil and natural gas properties and newly acquired properties. We may not be able to continue to replace reserves from these activities at acceptable costs. Lower prices for oil, NGLs, and natural gas may further limit the reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

RISKS RELATED TO REGULATIONS

New laws, policies, regulations, rulemaking, and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows, and operations.

Our business is subject to federal, state, and local laws and regulations on taxation, the exploration for and development, production, and marketing of oil and natural gas, and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, production rates, prevention of waste, unitization and pooling of properties, and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating, and abandoning our oil and natural gas wells and other facilities. These laws and regulations, and any others passed by the jurisdictions where we have production, could limit the number of wells drilled or the allowable production from successful wells, limiting our revenues.

We are (or could become) subject to complex environmental laws and regulations adopted by the jurisdictions where we own properties or operate. We could incur liability to governments or third parties for discharges of oil, natural gas, or other pollutants into the air, soil, or water, including responsibility for remedial costs. We could discharge these materials into the environment in many ways, including:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities, and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations;
- sabotage; and
- blowouts, cratering, and explosions.

Because the requirements imposed by laws and regulations often change, we cannot assure you that future laws and regulations, including changes to existing laws and regulations, will not have a material adverse effect on our business or results of operations. The United States Congress and White House administration may impose more stringent environmental requirements on our operations or change existing laws and regulations in a manner that could adversely impact our business. Stricter standards, greater regulation, and more extensive permit requirements could increase our future risks and costs related to environmental matters. Because we acquire interests in properties operated in the past by others, we may be liable for environmental damage caused by the former operators, which liability could be material.

Public and private initiatives could accelerate the transition away from fossil fuels and increase the costs of our operations.

In an effort to promote a lower-carbon economy, there are various public and private initiatives subsidizing or otherwise encouraging the development and adoption of alternative energy sources and technologies, including by mandating the use of specific fuels or technologies. These initiatives may reduce the competitiveness of carbon-based fuels, such as oil and natural gas, which could decrease demand for oil and natural gas having an adverse impact on our business.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could cause increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate the production of oil, natural gas, and associated liquids from dense subsurface rock formations. Our oil and natural gas operations routinely apply hydraulic-fracturing techniques to many of our oil and natural gas properties, including our plays in Texas and Oklahoma. Hydraulic-fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow hydrocarbons' flow into the wellbore. State oil and natural gas commissions process typically regulate this process, but the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and published permitting guidance addressing the performance of such activities. The EPA has also finalized rules under the Clean Water Act in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Separately, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that certain activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

Some states where we operate, including Texas and Oklahoma, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure of fracking fluids, waste disposal, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Local governments may also seek to restrict or prohibit well-drilling, hydraulic fracturing, or both. If state, local, or municipal legal restrictions are adopted in areas where we are conducting or plan to conduct operations, we may incur added costs to comply with such requirements that may be significant, experience delays or curtailment pursuing exploration, development, or production activities, and perhaps even be precluded from the drilling and completion of wells.

In addition, our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we cannot get adequate supplies of water for our drilling and completion operations or cannot dispose of or recycle the water we use at a reasonable cost and under applicable environmental rules. Any new laws, regulation, or permitting requirements regarding hydraulic fracturing could lead to operational delays, or increased operating costs or third party or governmental claims, and could result in additional burdens that could delay or limit the drilling services we provide to third parties whose drilling operations could be affected by these regulations or increase our costs of compliance and doing business and delay the development of unconventional gas resources from shale formations which are not commercial without using hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the oil and natural gas we can ultimately produce from our reserves.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect intended to supply coverage for losses solely related to hydraulic fracturing operations, but our general liability and excess liability insurance policies might cover third-party claims related to hydraulic fracturing operations and associated legal expenses depending on the specific nature of the claims, the timing of the claims, and the specific terms of such policies.

The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil, natural gas, and associated NGLs from many reservoirs requires the use and disposal of significant water quantities.

Our inability to secure enough water or dispose of or recycle the water used in our oil and natural gas operations could hurt our operations. Imposing new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil and natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and, use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could hurt our operations and financial condition.

The potential listing of species as "endangered" under the federal Endangered Species Act could cause increased costs and new operating restrictions or delays on our operations and of our customers, which could hurt our operations and financial results.

The ESA and similar state laws regulate various activities, including oil and gas development, which could harm species listed as threatened or endangered under the ESA or their habitats. Designating previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur added costs or become subject to operating delays, restrictions, or bans in affected areas, which impacts could reduce drilling activities in affected areas. Our operations could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Many species have been listed or are under consideration for protected status in areas we operate or could undertake operations, such as the dunes sagebrush lizard and greater sage grouse.

RISKS RELATED TO TERRORIST ATTACKS OR CYBER-ATTACKS

Terrorist attacks or cyber-attacks could have a material adverse effect on our business, financial condition, or results of operations.

Terrorist attacks or cyber-attacks may affect the energy industry and economic conditions, including our operations and our customers, general economic conditions, consumer confidence and spending, and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other United States targets. A cyber incident could cause information theft, data corruption, operational disruption, and financial loss. Our insurance may not protect us against such occurrences. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

We are increasingly dependent on digital technologies, including information systems, infrastructure, and cloud applications and services, to operate our businesses, process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of natural gas reserves, and perform other activities related to our businesses. Our business partners, including vendors, service providers, and financial institutions, also depend on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems to misappropriate assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could cause the unauthorized release, gathering, monitoring, misuse, loss, or destruction of proprietary and other information, or other disruption of our business operations. Some cyber incidents, like surveillance, may remain undetected for a long time.

Deliberate attacks on our assets, or security breaches in our systems or infrastructure, the systems or infrastructure of third-parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions, and third-party liability, including:

- a cyber-attack on a vendor or service provider could cause supply chain disruptions, which could delay or halt the development of more infrastructure, effectively delaying the start of cash flows from the project;
- a cyber-attack on our facilities may cause equipment damage or failure;
- a cyber-attack on mid-stream or downstream pipelines could prevent our products from being delivered, leading to losing revenues;
- a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

- deliberate corruption of our financial or operational data could cause events of non-compliance leading to regulatory fines or penalties; and
- business interruptions could cause expensive remediation efforts, the distraction of management, or damage to our reputation.

Implementation of various controls and processes to monitor and mitigate security threats and increase security for our information, facilities and infrastructure are costly and labor-intensive. There can be no assurance that such measures will prevent security breaches from occurring. As cyber threats continue to evolve, we may have to spend significant additional resources to modify or enhance our protective measures or investigate and remediate any information security vulnerabilities.

Rapid developments in artificial intelligence ("AI"), digital technologies, and cybersecurity risks may affect our operations and competitive position. The oil and gas industry is increasingly adopting AI, automation, and advanced data analytics to improve exploration, drilling efficiency, production optimization, and operational decision-making. At the same time, increased reliance on digital systems across the industry may expose companies to greater cybersecurity risks, including unauthorized access, data breaches, operational disruptions, or ransomware attacks. If we are unable to effectively respond to technological changes or adequately protect our information systems, our business, financial condition, and results of operations could be adversely affected.

RISKS RELATED TO OWNERSHIP OF OUR CAPITAL STOCK

Holders of the New Common Stock and Warrants could be subject to U.S. federal withholding tax and/or U.S. federal income tax and corresponding tax reporting obligations on the sale, exchange, or other disposition of the New Common Stock and Warrants, which could adversely affect the trading and liquidity of the New Common Stock and Warrants.

The Company believes that it is, and will remain for the foreseeable future, a "U.S. real property holding corporation" for U.S. federal income tax purposes. Under the Foreign Investment in Real Property Tax Act (FIRPTA), non-U.S. holders may be subject to U.S. federal income tax on the gain from the sale, exchange, or other disposition of shares of New Common Stock and Warrants, in which case they would also have to file U.S. federal income tax returns about that gain and may be subject to a U.S. federal withholding tax on a disposition of shares of New Common Stock and Warrants. Whether these FIRPTA provisions apply depends on the amount of New Common Stock or Warrants that the non-U.S. holders hold and whether, when they dispose of their New Common Stock or Warrants, the New Common Stock is treated as regularly traded on an established securities market under the Treasury Regulations (regularly traded).

If the New Common Stock is regularly traded during a calendar quarter, (A) no withholding requirements would be imposed under FIRPTA on transfers of New Common Stock or Warrants and (B) only a non-U.S. holder who has held, actually or constructively, (i) over 5% of New Common Stock or (ii) Warrants with a fair market value greater than 5% of the New Common Stock into which it is convertible, in each case at any time during the shorter of (x) the five years ending on the date of disposition, and (y) the non-U.S. holder's holding period for its shares of New Common Stock or Warrants, would be subject to U.S. federal income tax on the sale, exchange, or disposition of such shares of New Common Stock or Warrants during such calendar quarter under FIRPTA.

If during any calendar quarter the New Common Stock is not regularly traded, any purchaser of New Common Stock or Warrants generally will have to withhold (and remit to the Internal Revenue Service (IRS)) 15% of the gross proceeds from the sale of the New Common Stock or Warrants unless provided with a certificate of non-foreign status or an IRS withholding certificate from the seller. Because the New Common Stock and Warrants were issued in book-entry form through the Depository Trust Company (DTC), sellers may not provide the necessary documentation to the purchasers to establish an exemption from withholding. Additionally, the purchasers may not withhold from the purchase price and remit the withheld amount to the IRS if they cannot obtain the sellers' identifying information. It may be difficult or impossible to complete a transfer in compliance with tax laws in any calendar quarter when the New Common Stock is not regularly traded.

Our New Common Stock is currently quoted on the OTCQX® Best Market and may be treated as regularly traded during any calendar quarter in which it is regularly quoted on one of the OTC markets by brokers or dealers making a market in the New

Common Stock. But no assurances can be given that brokers or dealers will regularly quote the New Common Stock on such OTC market. If the New Common Stock is not regularly traded, the trading and liquidity of the New Common Stock and Warrants could be hurt because of the withholding and other tax obligations under FIRPTA.

Our New Common Stock may have a limited market and lack liquidity.

Our New Common Stock is quoted on the OTCQX® Best Market, which is a more limited market than the NYSE or The Nasdaq Stock Market. The quotation of our shares on such a marketplace may cause a less liquid market available for existing and potential shareholders to trade shares of our New Common Stock, depress the trading price of our New Common Stock, and have a long-term adverse impact on our ability to raise capital. There can be no assurance there will be an active market for our shares of New Common Stock, either now or in the future, or that shareholders can liquidate their investment or liquidate it at a price that reflects the business' value.

Our charter and by-laws contain provisions that could delay or discourage a change in control transaction or prevent shareholders from receiving a premium on their investment.

Our charter and bylaws contain provisions that may delay or discourage change in control transactions or changes in our management or transactions that our shareholders might otherwise deem to be in their best interests or that might result in a premium over the market price for our shares, including, among other things:

1. For so long as we do not have a class of securities registered under Section 12 of the Exchange Act, until the earlier to occur of (x) the Consenting Noteholders (as defined in the Plan) ceasing to hold at least 50% of the outstanding voting stock and (y) a public offering of common stock having occurred and shares of the Company's common stock with a value of at least $250.0 million having been listed for trading on a national securities exchange, the Company cannot take certain actions without the consent of holders of at least 50% of the voting stock. Such actions include, among other things and subject to certain exceptions, (i) increasing or decreasing the size of the Board of Directors, (ii) undertaking any fundamental change to the nature of the business, or (iii) consummating a public offering of common stock.
2. The Board of Directors is divided into two classes, Group I and Group II. The current Group I directors will serve until the Company's 2027 annual meeting of stockholders, and the current Group II directors will serve until the Company's 2026 annual meeting of shareholders. Each nominee for director will stand for election to a two-year term expiring at the second annual meeting of stockholders after that director's election and until such director's successor is duly elected and qualified, subject to that director's earlier resignation, retirement, removal from office, death, or incapacity.
3. Courts in Delaware are the exclusive forum for derivative actions and certain other actions and claims.
4. Special meetings of the shareholders may only be called by the Board of Directors or by the secretary of the Company at the written request of shareholders owning at least 25% of the voting stock.
5. The Board of Directors has the ability to authorize undesignated preferred stock. This ability makes it possible for our Board of Directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us.
6. Vacancies on our Board of Directors and newly created directorships will be filled solely by the affirmative vote of a majority of the remaining directors then in office, even if less than a quorum, or by a sole remaining director.
7. Advance notice requirements for nominations for election to the Board of Directors and business to be brought by shareholders before any annual meeting of shareholders.

Part D. Management Structure and Financial Information

The Name of the Chief Executive Officer, Members of the Board of Directors, as well as Control Persons

A. Officers and Directors

Information About Our Executive Officers

The table below and accompanying text sets forth certain information as of March 12, 2026, concerning each of our executive officers. There were no arrangements or understandings between any of the officers and any other person(s) under which the officers were elected.

Name	Age	Positions Held
Phil Frohlich	71	Director since September 3, 2020, Chief Executive Officer since April 1, 2023
Andrew E. Harding	48	Vice President, Secretary, and General Counsel since October 27, 2020, Associate General Counsel from March 2005 to October 27, 2020, Staff Attorney from August 2004 to March 2005
Thomas D. Sell	61	Chief Financial Officer since June 23, 2021; Chief Accounting Officer from December 31, 2020 to September 30, 2023; Interim Chief Financial Officer from October 22, 2020 to June 23, 2021
Karl Bode	67	Sr. Vice President, Business Development - Unit Petroleum Company since January 1, 2019

Mr. Frohlich was elected as a director in September 2020. He has served as Chief Executive Officer of the Company since April 1, 2023. He founded Prescott Capital Management in 1992 and has been serving as Managing Partner since. The Oklahoma-based hedge fund focuses on small and mid-cap stocks. Mr. Frohlich was formerly president of Tulsa-based Siegfried Companies Inc. and a tax principal with what is now the international accounting firm Ernst & Young. He received a B.B.A. in Economics from the University of Oklahoma in 1976, an M.B.A. at the University of Texas at Austin in 1980, and a J.D. from the University of Tulsa in 1993.

Mr. Harding joined Unit in August 2004 as a Staff Attorney. In March 2005, he was promoted to the position of Associate General Counsel. In October 2020, he was promoted to Vice President, General Counsel, and Secretary. Mr. Harding received his Bachelor of Business Administration from Baylor University in 2001, and his Juris Doctorate from the University of Tulsa College of Law in 2004. He is a member of the Oklahoma Bar Association. He is also a member of the Petroleum Alliance of Oklahoma board of directors and is chairman of the legal committee.

Mr. Sell joined Unit in October 2020 as Interim Chief Financial Officer and in June 2021, he became Chief Financial Officer. From March 2020 to October 2020, he was the Chief Financial Officer for Montereau, Inc., a retirement community. From 2016 to March 2020, Mr. Sell served as Chief Accounting Officer and Controller for SemGroup Corporation, a gathering, transportation, storage, distribution, marketing and other midstream services company. From 1996 to 2016, Mr. Sell was with Williams Companies, Inc., where he held several different management positions in finance and accounting. Mr. Sell was with Deloitte & Touche from 1987 to 1996. Mr. Sell received his Bachelor of Science in Accounting from Oral Roberts University, where he graduated magna cum laude. He is a certified public accountant.

Mr. Bode joined Unit in November 2012 as Manager of Non-Operated Properties. In 2014 he was promoted to Chief Engineer. In 2017 he was promoted to the position of Vice-President and subsequently was promoted to position of Sr. Vice-President in 2019. Mr. Bode received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa in 1981 and earned a Certified Public Accounting license in 1999. Prior to Unit, Mr. Bode held various engineering, accounting and management positions at QEP Resources, Kaiser-Francis Oil Company, Samson Resources Company and Chevron, USA.

Information About Our Directors

The table below and accompanying text sets forth certain information as of March 12, 2026, concerning each member of our Board of Directors (the "Board"). There is currently a vacancy in both Group 1 and Group 2.

Name	Age	Director Since	Group	Committees of the Board	Term Expires	Primary Occupation
Robert R. Anderson	68	2020	II		2026	Executive, GBK Corporation, Tulsa, Oklahoma
Alan J. Carr	55	2020	I	Compensation (Chair), Strategic Transactions, Audit	2027	Chief Executive Officer, Drivetrain, LLC, New York City, New York
Phil Frohlich	71	2020	II	Audit	2026	Chief Executive Officer, Unit Corporation; Managing Partner, Prescott Capital Management, Tulsa, Oklahoma
Philip B. Smith	74	2020	II		2026	Chairman of the Board, Unit Corporation, Tulsa, Oklahoma
Andrei Verona	47	2020	I	Strategic Transactions (Chair), Audit (Chair), Compensation	2027	Spectrum Fund Portfolio Manager at Saye Capital Management, headquartered in Rancho Palos Verdes, California

Mr. Anderson was elected as a director in September 2020. Since 2010 he has worked as an executive with GBK Corporation, a holding company with numerous energy industry subsidiaries and affiliates, including Kaiser Francis Oil Company, which has extensive domestic upstream oil & gas interests, and Cactus Drilling Company, which is a major domestic contract drilling company, serving on numerous private boards including Summit ESP which was acquired by Halliburton in 2017. Between 2002 and 2010 Mr. Anderson engaged primarily in personal investing with a focus on oil & gas supply/demand fundamentals while simultaneously serving on the University of Kansas Chemical & Petroleum Engineering Board of Advisors. In 1998, he was co-founder and CEO of privately held Sapient Energy Corp which was subsequently sold to Chesapeake Energy in 2002. During his time with Sapient, Mr. Anderson was also actively involved on the IPAA's Capital Markets Committee. Prior to establishing Sapient Energy, Mr. Anderson worked for Kaiser-Francis Oil Company in various roles of increasing responsibilities from 1984 through 1997. After graduating from the University of Kansas in 1980 with a BS degree in Chemical Engineering, he worked for Amoco Production Company until 1984. Attributes, experience, and qualifications for board and committee service: energy industry experience; executive expertise; entrepreneurial expertise; capital markets expertise.

Mr. Carr was elected as a director in September 2020. Since September 2013 he has worked as the Managing Member and Chief Executive Officer of Drivetrain, LLC, an independent fiduciary services firm. He has been a distressed investing and turnaround professional, with 25 years of experience in principal investing, advisory mandates, and board of directors' service, including complex financial restructurings and reorganizations in the U.S. and Europe. From 2003 to 2013, Mr. Carr was Managing Director at Strategic Value Partners, a global investment firm focused on distressed debt and private equity opportunities. Mr. Carr started his career at Skadden, Arps, Slate, Meagher & Flom LLC and Ravin, Sarasohn, Baumgarten, Fisch & Rosen in corporate restructuring advisory. He received a B.A. in Economics and Sociology from Brandeis University in 1992 and earned a J.D. from Tulane Law School in 1995. Mr. Carr currently serves as a director for the following public company: NewLake Capital Partners (since 2019). Public companies for which Mr. Carr no longer serves as director but on which he served as a director in the last five years include: Sears Holdings Corporation; Enjoy Technology, Inc.; Atlas Iron Limited; TEAC Corporation; Tidewater Inc.; Midstates Petroleum Company, Inc.; Verso Corporation; McDermott International, Inc.; Basic Energy Services; and J.C. Penney Corporation, Inc., a subsidiary of J.C. Penney Co. Attributes, experience, and qualifications for board and committee service: executive leadership experience; complex financial restructuring and reorganization expertise; financial analysis expertise; board of director service experience; and legal expertise.

Mr. Frohlich biographical information is listed in the section above setting forth information about our officers. Attributes, experience, and qualifications for board and committee service: executive and entrepreneurial experience; accounting, investment, business and legal expertise.

Mr. Smith was named to the Board of Directors on September 3, 2020, and became Chairman on September 8, 2020. He served as President and Chief Executive Officer of the Company from October 2020 to March 2023. Before his appointment to Unit's Board, he was self-employed since 2002. Mr. Smith served on the Board of Directors of Eagle Rock Energy LP from 2007 to 2015. Mr. Smith was Chief Executive Officer and Chairman of Prize Energy Corp., which he co-founded with Natural Gas Partners in 1999, until the company's merger with Magnum Hunter Resources in 2002. Mr. Smith also served as Chief Executive Officer of Tide West Oil Company until it was sold to HS Resources in 1996. He received a B.S. in Mechanical Engineering from Oklahoma State University and a Master of Business Administration from the University of Tulsa. Attributes, experience, and qualifications for board and committee service: executive leadership experience and industry familiarity; entrepreneurial and business experience; and engineering background.

Mr. Verona was elected as a director in September 2020. He is an advisor to Saye Capital Management, an opportunistic credit hedge fund headquartered in Rancho Palos Verdes, California, where he previously was a portfolio manager from 2013 to 2024. He helps manage the corporate portion of the portfolio, which invests primarily in high yield and distressed bonds with a focus on restructurings and other event-driven opportunities. From 2009 to 2013, Mr. Verona was with Gleacher & Company's Investment Banking Group, serving most recently as Vice President. At Gleacher he focused on middle market corporates, advising clients on in-court and out-of-court restructurings, financings, and M&A transactions. Prior to Gleacher, he was a Senior Associate in GSC Partners' Corporate Credit Group. Mr. Verona started his career in the convertible bond and structured credit groups at Pacific Investment Management Company (PIMCO). He graduated cum laude from the University of California Los Angeles with a degree in Economics. Mr. Verona is a director for Iracore International, a private company, where he serves as the Audit Chair and Special Committee Chair. From November 2020 to October 2021, he served as a director for the public company Lonestar Resources US Inc., where he was the Audit Chair and a member of the Compensation Committee. Attributes, experience, and qualifications for board and committee service: complex investment and securitization experience; financial analysis expertise; M&A expertise; restructuring experience; and director experience.

Compensation of Officers and Directors

Beneficial share ownership of Officers and Directors as of March 12, 2026:

Name and Business Address*	Position	Common Stock	Restricted Stock Units Vesting within 60 days	Options Exercisable within 60 days	Total Beneficially Owned Shares (1)
Phil Frohlich (2)	Chief Executive Officer and Director	21,594	—	—	21,594
Thomas D. Sell	Chief Financial Officer	20,000	—	—	20,000
Andrew E. Harding	Vice President, Secretary and General Counsel	14,445	—	—	14,445
Karl Bode	Senior Vice President, Business Development – Unit Petroleum Company	18,181	—	—	18,181
Robert R. Anderson	Director	42,860	—	—	42,860
Alan J. Carr	Director	21,594	—	—	21,594
Philip B. Smith	Director and Chairman of the Board	67,667	—	—	67,667
Andrei Verona	Director	21,594	—	—	21,594

*All officers and directors may be contacted at Unit Corporation's address.

1. Beneficial share ownership includes vested restricted stock units, vested options, and restricted stock units and options scheduled to vest within 60 days of March 12, 2026.
2. Mr. Frohlich manages Prescott Group Capital Management, which owns 3,517,707 shares of Unit Corporation's common stock.

The following tables set forth the aggregate compensation paid by Unit Corporation for services rendered by its Executive Officers and Directors during the periods indicated:

Executive Officers

Name and Principal Position	Year Ended	Salary ($)	Cash Bonus ($)	Restricted Stock Units Awards ($)	Performance Restricted Stock Units Awards ($)	Option Awards ($)	Total ($)
Phil Frohlich, Chief Executive Officer (1)	2025	$ —	$ —	$ —	$ —	$ —	$ —
	2024	$ —	$ —	$ —	$ —	$ —	$ —
Thomas D. Sell, Chief Financial Officer	2025	$ 360,000	$ 226,800	$ 98,266	$ 95,890	$ —	$ 780,956
	2024	$ 351,900	$ 244,340	$ 73,892	$ 119,284	$ —	$ 789,416
Andrew E. Harding, Vice President, Secretary and General Counsel	2025	$ 310,000	$ 139,500	$ 60,437	$ 58,979	$ —	$ 568,916
	2024	$ 299,115	$ 148,349	$ 44,883	$ 72,414	$ —	$ 564,761
Chris Menefee, President - Unit Drilling Company (2)	2025	$ 247,500	$ 173,250	$ —	$ —	$ —	$ 420,750
	2024	$ 330,000	$ 229,134	$ 69,295	$ 111,864	$ —	$ 740,293
Karl Bode, Senior Vice President, Business Development - Unit Petroleum Company	2025	$ 307,000	$ 138,150	$ 59,856	$ 58,413	$ —	$ 563,419
	2024	$ 300,000	$ 148,788	$ 44,992	$ 72,641	$ —	$ 566,421

1. See Director Compensation Table for information regarding Mr. Frohlich’s director’s fees and equity awards.
2. Mr. Menefee’s employment was terminated on October 1, 2025 in conjunction with the sale of Unit Drilling Company.

Directors

Our directors fees are structured as set forth in the table below:

Annual retainer	$65,000
Annual retainer for each committee a board member serves on	$10,000
Additional compensation for service as board chair	$15,000
Reimbursement for expenses incurred attending stockholder, board, and committee meetings	Yes

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Name	Year Ended		Director's Fees ($)	Restricted Stock Units Awards ($)	Option Awards ($)	Total ($)
Robert R. Anderson	2025	$	65,000 $	121,849 $	— $	186,849
	2024	$	65,000 $	195,471 $	— $	260,471
Alan J. Carr	2025	$	85,000 $	121,849 $	— $	206,849
	2024	$	85,000 $	125,015 $	— $	210,015
Phil Frohlich	2025	$	75,000 $	121,849 $	— $	196,849
	2024	$	75,000 $	125,015 $	— $	200,015
Steven B. Hildebrand (1)	2025	$	85,000 $	121,849 $	— $	206,849
	2024	$	85,000 $	125,015 $	— $	210,015
Philip B. Smith	2025	$	80,000 $	121,849 $	— $	201,849
	2024	$	80,000 $	125,015 $	— $	205,015
Andrei Verona	2025	$	95,000 $	121,849 $	— $	216,849
	2024	$	95,000 $	125,015 $	— $	220,015

1. Mr. Hildebrand retired from the Board effective at the conclusion of the Company's 2025 Annual Meeting.

B. Other Control Persons

As of December 31, 2025, the following shareholders beneficially own 5% or more of Unit Corporation's common stock:

Name	Address	Number of Shares Beneficially Owned
Prescott Group Capital Management, LLC	1924 South Utica Avenue, Suite 1120, Tulsa, Oklahoma 74104	3,517,707
NYL Investors LLC	51 Madison Avenue, 2nd Floor, New York, New York 10010	623,361

Unit Corporation is not aware of any additional shareholders beneficially owning 5% or more of our common stock. It is possible that there are one or more additional holders of a significant percentage of our common stock, however the federal securities laws do not require a shareholder of 5% or more of our common stock to disclose that information publicly or to the Company. The table above is based on the best information available to the Company.

C. Legal/Disciplinary History

None of the officers, directors, promoters, or control persons of Unit has, in the past five years, been the subject of any of the following:

- A conviction in a criminal proceeding or named as a defendant in a pending criminal proceeding (excluding traffic violations and other minor offenses);
- The entry of an order, judgment or decree, not subsequently reversed, suspended or vacated, by a court of competent jurisdiction that permanently or temporarily enjoined, barred, suspended, or otherwise limited such person's involvement in any type of business, securities, commodities, or banking activities;
- A finding or judgment by a court of competent jurisdiction (in a civil action), the SEC or the Commodity Futures Trading Commission, or a state securities regulator of a violation of federal or state securities or commodities law, which finding or judgment has not been reversed, suspended, or vacated; or
- The entry of an order by a self-regulatory organization that permanently or temporarily barred, suspended, or otherwise limited such person's involvement in any type of business or securities activities.

D. Disclosure of Family Relationships

None.

E. Disclosure of Related Party Transactions

Certain Transactions Between the Company and Its Officers, Directors, and Their Associates

One current director, Robert Anderson, also serves as an executive with GBK Corporation, a holding company with numerous energy and industry subsidiaries and affiliates, including Kaiser Francis Oil Company and Cactus Drilling Company, L.L.C. The Company in the ordinary course of business, made payments for working interests, joint interest billings, drilling services, and product purchases to, and received payments for working interests, joint interest billings, and contract drilling services from, Kaiser Francis Oil Company. Payments made to Kaiser Francis Oil Company totaled $4.3 million and $0.9 million during 2025 and 2024, respectively, while payments received totaled $2.7 million and $4.3 million during 2025 and 2024, respectively.

The sale of UDC to Cactus Drilling Company, L.L.C. is considered a transaction with a related party due to Mr. Anderson's position with GBK.

F. Disclosure of Conflicts of Interest

None.

The name, address, telephone number, and email address of each of the following outside providers that advise the issuer on matters relating to operations, business development and disclosure:

1. Investment Banker:	None
2. Promoters:	None
3. Disclosure Counsel:	Conner & Winters, LLP 15 E. 5th St., Suite 4100 Tulsa, OK 74103 (918) 586-5711 https://www.cwlaw.com/
4. Auditor:	Grant Thornton LLP 6120 S. Yale Ave., Suite 1400 Tulsa, OK 74136 (918) 877-0800 https://www.grantthornton.com/
5. Public Relations Consultant:	None
6. Investor Relations Consultant:	None
7. Corporate Secretary:	Drew Harding, Vice President, General Counsel, and Secretary 8200 S. Unit Dr. Tulsa, OK 74132 (918) 493-7700 drew.harding@unitcorp.com
8. Any Other Advisor:	None

Auditor Fees and Services

Preparation of the consolidated financial statements is the responsibility of Unit's management. Grant Thornton LLP is responsible for expressing an opinion on the consolidated financial statements based on their audit procedures. Grant Thornton LLP has confirmed to us that the firm is licensed to practice public accounting in the states in which we conduct our business and is registered with the PCAOB.

The table below presents the fees for professional services paid to Grant Thornton LLP during the years indicated:

Type of Service		2025		2024
Audit Fees	$	522,500	$	550,000
Audit-Related Fees [1]	$	27,563	$	26,500
Tax Fees [2]	$	9,315	$	32,554
All Other Fees		—		—
Total	$	559,378	$	609,054

1. Audit-related fees include professional services for the audit of the Unit Corporation 401(k) Employee Thrift Plan's financial statements.
2. Tax fees include professional services related to the review and assistance with selected income tax filings and various consulting projects.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Auditor

The audit committee has responsibility for appointing, setting compensation, and overseeing the work of the independent certified public accounting firm. In recognition of this responsibility, the audit committee has established a policy to pre-approve all audit and permissible non-audit services provided by the independent certified public accounting firm.

Before incurring the following, management will submit to the audit committee for approval a list of services and related fees expected to be rendered by our independent certified public accounting firm during that year within these four categories of services:

(1) Audit services include audit work performed on the financial statements, internal control over financial reporting, and work that generally only the independent certified public accounting firm can reasonably be expected to provide, including comfort letters, statutory audits, and discussions surrounding the proper application of financial accounting and reporting standards.

(2) Audit-related services are for assurance and related services traditionally performed by the independent certified public accounting firm, including due diligence related to mergers and acquisitions, employee benefit plan audits, and special procedures required to meet certain regulatory requirements.

(3) Tax services include all services, except those services specifically related to the audit of the financial statements performed by the independent certified public accounting firm's tax personnel, including tax analysis; assisting with coordination of execution of tax related activities, primarily in corporate development; supporting other tax related regulatory requirements; and tax compliance and reporting.

(4) Other Fees are those associated with services not captured in the other categories.

The audit committee pre-approves the independent certified public accounting firm's services within each category. The fees are budgeted and the audit committee requires the independent certified public accounting firm and management to report actual fees versus the budget periodically throughout the year. Circumstances may arise when it may become necessary to engage the independent certified public accounting firm for additional services not contemplated in the original pre-approval categories. In those instances (subject to certain de minimus exceptions), the audit committee requires specific pre-approval before engaging the independent certified public accounting firm.

The audit committee may (and has at various times in the past) delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated must report, for informational purposes only, any pre-approval decisions to the audit committee at its next scheduled meeting.

Index to the Consolidated Financial Statements
Unit Corporation and Subsidiaries

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

Board of Directors
Unit Corporation

Opinion

We have audited the consolidated financial statements of Unit Corporation (a Delaware corporation) and subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2025 and 2024, and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for opinion

We conducted our audits of the consolidated financial statements in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of management for the financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the consolidated financial statements are issued.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
March 12, 2026

UNIT CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2025	As of December 31, 2024
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 181,713	$ 48,884
Accounts receivable, net of allowance for credit losses of $2.8 and $2.9 million at December 31, 2025 and December 31, 2024, respectively	14,273	37,554
Current derivative assets (Note 16)	2,135	534
Prepaid expenses and other	2,349	3,278
Total current assets	200,470	90,250
Property and equipment:		
Oil and natural gas properties, on the full cost method:		
Proved properties	191,183	167,347
Unproved properties not being amortized	6,703	10,655
Drilling equipment	—	95,292
Other	5,821	9,391
Property and equipment, gross	203,707	282,685
Less: accumulated depreciation, depletion, amortization, and impairment	104,044	130,890
Property and equipment, net	99,663	151,795
Deferred tax assets, net (Note 12)	19,177	32,979
Right of use asset (Note 18)	1,732	3,915
Other assets	9,700	10,304
Total assets	$ 330,742	$ 289,243
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 9,052	$ 11,718
Accrued liabilities (Note 8)	15,067	16,372
Current operating lease liabilities (Note 18)	1,743	2,436
Current portion of other long-term liabilities (Note 9)	2,554	1,942
Total current liabilities	28,416	32,468
Operating lease liabilities (Note 18)	40	1,589
Other long-term liabilities (Note 9)	21,212	22,665
Commitments and contingencies (Note 19)		
Shareholders' equity:		
Preferred stock, $0.01 par value, 1,000,000 shares authorized, none issued	—	—
Common stock, $0.01 par value, 25,000,000 shares authorized; 12,486,477 shares issued and 9,895,773 outstanding at December 31, 2025, and 12,265,268 shares issued and 9,747,725 outstanding at December 31, 2024	124	123
Treasury stock (Note 6)	(82,839)	(82,703)
Capital in excess of par value	268,038	267,670
Retained earnings	95,751	47,431
Total shareholders' equity	281,074	232,521
Total liabilities and shareholders' equity	$ 330,742	$ 289,243

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

UNIT CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2025	Year Ended December 31, 2024
	(In thousands except per share amounts)	
Revenues:		
Total revenues	$ 102,283	$ 93,248
Expenses:		
Operating costs	42,851	44,420
Depreciation, depletion, and amortization	9,525	8,221
General and administrative	22,406	22,497
(Gain) loss on disposition of assets (Note 5)	(14)	114
Total operating expenses	74,768	75,252
Income from operations	27,515	17,996
Other income (expense):		
Interest income	3,619	4,104
Interest expense	(34)	(55)
Gain on derivatives, net (Note 16)	9,100	534
Reorganization items, net	—	(84)
Other, net	(463)	(291)
Total other income	12,222	4,208
Income from continuing operations before income taxes	39,737	22,204
Income tax expense (benefit), net (Note 12):		
Current	4	—
Deferred	(1,821)	4,736
Total income tax expense (benefit), net	(1,817)	4,736
Income from continuing operations	41,554	17,468
Income from discontinued operations, net of tax (including gain on disposal of $56,459)	56,738	29,777
Net income	$ 98,292	$ 47,245
Basic net income per common share (Note 7):		
Continuing operations	$ 4.18	$ 1.78
Discontinued operations	5.71	3.03
Total basic earnings per common share	$ 9.89	$ 4.82
Diluted net income per common share (Note 7):		
Continuing operations	$ 4.17	$ 1.75
Discontinued operations	5.70	2.99
Total diluted earnings per common share	$ 9.87	$ 4.75

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

UNIT CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Shareholders' Equity Attributable to Unit Corporation				
	Common Stock	Treasury Stock	Capital In Excess of Par Value	Retained Earnings (Deficit)	Total
			(In thousands)		
Balances, December 31, 2023	$ 122	$ (79,399)	$ 263,555	$ 69,848	$ 254,126
Net income	—	—	—	47,245	47,245
Dividends declared (Note 6)	—	—	—	(69,662)	(69,662)
Stock-based compensation	—	—	4,597	—	4,597
Exercise of stock options, net of shares withheld for taxes and exercise price	1	—	(486)	—	(485)
Exercise of warrants, net of shares withheld for exercise price	—	—	4	—	4
Repurchases of common stock	—	(3,304)	—	—	(3,304)
Balances, December 31, 2024	$ 123	$ (82,703)	$ 267,670	$ 47,431	$ 232,521
Net income	—	—	—	98,292	98,292
Dividends declared (Note 6)	—	—	—	(49,972)	(49,972)
Stock-based compensation	—	—	1,697	—	1,697
Exercise of stock options, net of shares withheld for taxes and exercise price	1	—	(1,329)	—	(1,328)
Repurchases of common stock	—	(136)	—	—	(136)
Balances, December 31, 2025	$ 124	$ (82,839)	$ 268,038	$ 95,751	$ 281,074

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

UNIT CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,	
	2025	2024
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 98,292	$ 47,245
Adjustments to reconcile net income to net cash provided by operating activities:		
Income from discontinued operations, net of tax	(56,738)	(29,777)
Depreciation, depletion and amortization	9,525	8,221
Gain on derivatives, net (Note 16)	(9,100)	(534)
Cash receipts on derivatives settled (Note 16)	7,498	—
Deferred tax expense (benefit) (Note 12)	(1,821)	4,735
(Gain) loss on disposition of assets (Note 5)	(14)	114
Stock-based compensation plans (Note 15)	1,697	4,597
Change in credit loss reserve	52	186
ARO liability accretion (Note 10)	894	800
Contract assets and liabilities, net	—	(176)
Other, net	203	(2,165)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(1,406)	2,681
Prepaid expenses and other	502	2
Accounts payable	(119)	(5,197)
Accrued liabilities	1,026	(1,562)
Net change in operating assets and liabilities	3	(4,076)
Net cash provided by operating activities-continuing operations	50,491	29,170
Net cash provided by operating activities-discontinued operations	40,563	46,046
Net cash provided by operating activities	91,054	75,216
INVESTING ACTIVITIES:		
Capital expenditures	(23,598)	(14,083)
Proceeds from sale of Superior investment	—	8,000
Proceeds from disposition of property and equipment (Note 5)	3,740	3,670
Net cash used in investing activities-continuing operations	(19,858)	(2,413)
Net cash provided by (used in) investing activities-discontinued operations	113,350	(9,164)
Net cash provided by (used in) investing activities	93,492	(11,577)
FINANCING ACTIVITIES:		
Dividend and dividend equivalent payments (Note 6)	(50,253)	(71,749)
Payments for employee taxes on net settlement of equity awards (Note 15)	(1,328)	(486)
Proceeds from exercise of warrants (Note 6)	—	5
Repurchases of common stock (Note 6)	(136)	(3,304)
Net cash used in financing activities-continuing operations	(51,717)	(75,534)
Net cash used in financing activities-discontinued operations	—	—
Net cash used in financing activities	(51,717)	(75,534)
Net increase (decrease) in cash and cash equivalents	132,829	(11,895)
Cash and cash equivalents, beginning of period	48,884	60,779
Cash and cash equivalents, end of period	$ 181,713	$ 48,884

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

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Supplemental disclosure of cash flow information:		
Cash paid (received) for:		
Interest	$ 33	$ 89
Income taxes	526	1,701
Reorganization Items	—	(84)
Changes in accounts payable and accrued liabilities related to purchases of property and equipment	861	1,096
Changes in accrued liabilities related to dividends declared, but not yet paid	(281)	(2,087)
Non-cash changes to oil and natural gas properties related to asset retirement obligations	2,738	487
Non-cash (additions) reductions to oil and natural gas properties related to net changes in asset retirement obligations, accounts receivable, accounts payable, and accrued liabilities resulting from divestitures	—	(587)
Non-cash trade of property and equipment	—	(135)

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

UNIT CORPORATION AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – ORGANIZATION AND BUSINESS

Unless the context clearly indicates otherwise, references in this report to “Unit”, “Company”, “we”, “our”, “us”, or like terms refer to Unit Corporation or, as appropriate, its subsidiary, Unit Petroleum Company.

We are engaged in the development, acquisition, and production of oil and natural gas properties through our wholly-owned subsidiary Unit Petroleum Company (UPC). Our producing oil and natural gas properties, and related assets, are primarily located in Oklahoma and Texas.

Sale of Unit Drilling Company

On October 1, 2025, we signed and simultaneously closed a definitive agreement to sell our wholly-owned contract drilling subsidiary Unit Drilling Company (UDC) to Cactus Drilling Company, L.L.C., a related party, for cash consideration of $119.7 million.

The sale of UDC will change our operations and financial results going forward. Accordingly, the results of operations and cash flows for UDC have been classified as discontinued operations for all periods presented and prior periods have been retrospectively adjusted in the consolidated statements of operations and consolidated statements of cash flows.

See Note 22 –Discontinued Operations for further discussion.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation. The consolidated financial statements include the accounts of Unit Corporation and its wholly-owned subsidiary, UPC.

We evaluated our disclosure of subsequent events through March 12, 2026, the date the consolidated financial statements were issued.

Accounting Estimates. Preparing financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. Actual results could differ from those estimates. Significant estimates and assumptions include:

- oil and gas reserves quantities and values;
- full cost ceiling test and impairment assessments for property and equipment;
- asset retirement obligations (ARO);
- fair value of commodity derivative assets and liabilities;
- fair value of stock-based compensation grants or modifications;
- workers' compensation liabilities;
- contingency, litigation, and environmental liabilities; and
- realizability of deferred tax assets.

Cash and Cash Equivalents. We include as cash and cash equivalents all cash on hand and on deposit, as well as highly liquid investments with maturities of three months or less which are readily convertible into known amounts of cash. The financing section of our consolidated statements of cash flows reflects bank overdraft activity. Bank overdrafts are checks issued before the end of the period, but not presented to our bank for payment before the end of the period. There were no bank overdrafts as of December 31, 2025 or December 31, 2024.

We had a concentration of cash with one bank of $1.4 million and $1.8 million as of December 31, 2025 and 2024, respectively. We also had a concentration of cash equivalents of $90.9 million and $90.9 million in two separate money market funds comprised of U.S. Government and U.S. Treasury securities as of December 31, 2025 compared to cash equivalents of $25.1 million and $23.5 million in those funds as of December 31, 2024.

Accounts Receivable, Net of Allowance for Credit Losses. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for expected credit losses. We estimate the allowance for credit losses based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for credit losses only after all collection attempts have been unsuccessful.

Property and Equipment.

Oil and Natural Gas Properties. We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Under the full cost method, we capitalize all productive and non-productive costs incurred in connection with the acquisition, exploration, and development of our oil, NGLs, and natural gas reserves, including directly related overhead costs and related asset retirement costs. We did not capitalize any directly related overhead costs for the years ended December 31, 2025 or 2024.

Capitalized costs are amortized on a units-of-production method based on proved oil and natural gas reserves. The calculation of DD&A includes all capitalized costs, estimated future expenditures to be incurred in developing proved reserves, and estimated dismantlement and abandonment costs, net of estimated salvage values less accumulated amortization, unproved properties, and equipment not placed in service. The average rates used for DD&A were $2.21 and $1.97 per Boe for the years ended December 31, 2025 and 2024, respectively.

No gains or losses are recognized on the sale, conveyance, or other disposition of oil and natural gas properties unless it results in a significant alteration to our full cost pool.

Other property and equipment. Other property and equipment are carried at cost less accumulated depreciation. Refurbishments and enhancements are capitalized while repairs and maintenance are expensed. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets, typically ranging from 3 to 15 years.

Impairment and disposal. We review the carrying amounts of long-lived assets for potential impairment when events or changes in circumstances suggest the carrying amounts may not be recoverable. Changes that could prompt an assessment include equipment obsolescence, declines in the market demand for an asset, declines in commodity prices, or overall unfavorable changes in general market conditions. Assets are determined to be impaired if the 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. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect our assumptions and judgments regarding future industry conditions and their effect on future costs. Using different estimates and assumptions could result in materially different carrying values of our assets.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in income from operations. Any proceeds are credited to accumulated depreciation unless proceeds would exceed remaining cost, in which case excess proceeds are recorded as a gain on disposition of assets.

Capitalized Interest. Interest costs associated with major asset additions are capitalized during the construction period using a weighted average interest rate based on our outstanding borrowings. We did not capitalize any interest costs during the years ended December 31, 2025 or 2024.

Leases. We enter into various agreements to lease equipment and buildings, and we review each agreement to determine if they contain operating or finance leases with a term greater than 12 months. We recognize a lease liability on identified leases for the obligation to make lease payments and a right-of-use asset for the right to use the underlying asset for the lease term based on the present value of lease payments over the lease term which includes all noncancelable periods as well as periods covered by options to extend the lease that we are reasonably certain to exercise. Leases with an initial term of 12 months or less are not recorded as a lease right-of-use asset and liability. Most leases are valued using an incremental borrowing rate, which is determined based on information available at the commencement date of a lease, as an implicit borrowing rate cannot be determined under most of our leases. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. These options are evaluated at inception and throughout the contract term to determine if a modification of the lease term is required.

Expenses related to leases determined to be operating leases will be recognized on a straight-line basis over the lease term including any reasonably certain renewal periods, while those determined to be finance leases will be recognized following a front-loaded expense profile in which interest and amortization are presented separately in the consolidated statements of operations. The determination of whether a lease is accounted for as a finance lease or an operating lease requires management's estimates of the fair value of the underlying asset and its estimated economic useful life, among other considerations.

ARO. We record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The estimated liabilities related to these future costs are recorded at the time the wells are drilled or acquired. We use historical experience to determine the estimated plugging costs considering the well's type, depth, physical location, and ultimate productive life. A risk-adjusted discount rate and an inflation factor are applied to estimate the present value of these obligations. We depreciate the capitalized asset retirement cost and accrete the obligation over time. Revisions to the obligations and assets are recognized at the appropriate risk-adjusted discount rate with a corresponding adjustment made to the full cost pool.

Insurance. We are self-insured for certain losses relating to workers' compensation, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from zero to $1.0 million. We have purchased stop-loss coverage to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. There is no assurance that the insurance coverages we have will adequately protect us against liability from all potential consequences. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles, or any combination of these rather than pay higher premiums.

Subsequent to December 31, 2025, we elected to cease self-insurance for workers' compensation, control of well, and employee medical benefits and switched to premium based plans.

Commodity Derivatives. All commodity derivatives are recognized on the consolidated balance sheets as either an asset or liability measured at fair value and our commodity derivative counterparty is subject to a master netting agreement. We net the value of the derivative transactions with the same counterparty if a legal right to set-off exists. Changes in the fair value of our commodity derivatives and gains or losses on commodity derivative settlements are reported in gain on derivatives in our consolidated statements of operations. Cash settlements received or paid for matured, early-terminated, and/or modified derivatives are reported in cash payments on derivatives settled in our consolidated statements of cash flows.

Income Taxes. Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax basis of assets and liabilities and their reported amounts in the Company's consolidated financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. U.S. GAAP requires the recognition of a deferred tax asset for net operating loss carryforwards and tax credit carryforwards. We periodically assess the realizability of the deferred tax assets by considering all available evidence (both positive and negative) to determine whether it is more likely than not that all or a portion of the deferred tax assets will not be realized and a valuation allowance is required.

Natural Gas Balancing. When there are insufficient remaining reserves to offset a gas imbalance, we recognize an asset or a liability for the under-produced or over-produced position. We have recorded a receivable of $3.7 million and a liability of $3.0 million as of December 31, 2025 on certain properties where we estimate that insufficient reserves are available for us to recover our under-production from future production volumes or insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes, respectively. Our policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which we have imbalances are not material.

Stock-Based Compensation. We recognize the cost of stock-based compensation over the requisite service periods, which is generally the vesting period, based on the grant date fair value of those awards and account for forfeitures as they occur.

NOTE 3 - IMPAIRMENTS

There were no impairments recorded during the years ended December 31, 2025 or 2024.

NOTE 4 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Our revenue is reported under one segment in Note 21 – Industry Segment Information. Our revenue is from sales of our oil and natural gas production.

Oil and Natural Gas Revenue

Typical types of revenue contracts entered into by our oil and gas segment are oil sales contracts, North American Energy Standards Board (NAESB) Contracts, Gas Gathering and Processing Agreements, and revenues earned as the non-operated party with the operator serving as an agent on our behalf under joint operating agreements. Consideration received is variable and settled monthly while contract terms can range from a single month or evergreen to terms of a decade or more. Revenue from oil and natural gas sales is recognized when the customer obtains control of the product, which typically occurs at the point of delivery to the customer.

Certain costs, which can either reduce revenue or be recorded as an expense, are determined based on when control of the product is transferred to our customer. These costs affect our total revenue recognized, but do not impact gross profit. For example, gathering, processing and transportation costs included in the contract price with the customer on transfer of control of the product are part of the transaction price. In contrast, costs incurred while we control the product are recorded as operating costs.

Contract Assets and Liabilities

We have recognized no contract assets or liabilities during the years ended December 31, 2025 or 2024.

NOTE 5 – ACQUISITIONS AND DIVESTITURES

Contract Drilling

As discussed in Note 1 – Organization and Business, the Company sold its wholly-owned subsidiary UDC on October 1, 2025 for cash consideration of $119.7 million to Cactus Drilling Company, L.L.C., a related party. See additional details in Note 22 – Discontinued Operations.

Oil and Natural Gas

Net proceeds for the sale of non-core oil and natural gas assets totaled $3.7 million and $2.9 million during the years ended December 31, 2025 and 2024, respectively. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sales did not result in a significant alteration of the full cost pool.

During December 2024, the Company acquired approximately 1,000 acres of oil and gas leases for $3.0 million, of which $0.8 million consideration was paid at closing while $2.2 million was accrued for as of December 31, 2024. In separate transactions, during 2024 the Company also acquired approximately 1,600 acres of oil and gas leases for approximately $4.1 million and made prepayments of $2.5 million on two gross wells. All properties are located in Oklahoma.

In 2025, approximately 1,462 acres of oil and gas leases were developed through new drilling on the leases which were acquired in 2024. The company transferred the leasing costs associated with that acreage to the full cost pool.

NOTE 6 – SHAREHOLDERS' EQUITY AND DIVIDENDS

Common Stock

On September 3, 2020 (Emergence Date), the Company emerged from Chapter 11 bankruptcy and authorized the issuance of a total of 12.0 million shares of common stock at a par value of $0.01 per share (New Common Stock) to be subsequently distributed in accordance with the Chapter 11 plan of reorganization filed with the bankruptcy court on June 9, 2020 (as amended, supplemented and modified from time to time, the Plan). On February 21, 2023, a final decree was approved to close the remaining Chapter 11 case and grant related relief. As a result, any shares of common stock not yet claimed were deemed unclaimed property and have been treated as reductions to the number of shares of common stock issued and outstanding as of February 21, 2023.

Under the terms of our certificate of incorporation, the prohibition of any stockholder that owns 4.75% or more of the outstanding shares of our common stock acquiring additional shares without approval by the Board of Directors expired on September 3, 2025.

Common Stock Repurchases

During the year ended December 31, 2025, the Company repurchased 4,500 shares under the repurchase program at an average share price of $30.13 (unadjusted for dividends paid) for an aggregate purchase price of $0.1 million.

As of December 31, 2025, we had repurchased a total of 2,574,246 shares of common stock since emergence from bankruptcy at an average share price of $32.16 (unadjusted for dividends paid) for an aggregate purchase cost of $82.8 million. These repurchases were made through private and open market transactions made under the repurchase program authorized by the Board of Directors in June 2021 (as amended), as well as other privately negotiated transactions. The purchase cost and any direct acquisition costs are reflected as treasury stock on the consolidated balance sheets.

As of December 31, 2025, the remaining value of shares that may be purchased under the repurchase program authorization was $27.7 million.

Dividends

The table below presents information about the dividends paid during the periods indicated:

	Type	Dividend per share	Total Amount [1]	Record Date	Payment Date
2024			**(In thousands)**		
First quarter	Quarterly	$ 1.25	$ 12,269	March 18, 2024	March 28, 2024
Second quarter	Quarterly	$ 1.25	$ 12,961	June 17, 2024	June 27, 2024
Third quarter	Quarterly	$ 1.25	$ 12,248	September 16, 2024	September 27, 2024
Fourth quarter	Quarterly	$ 1.25	$ 12,185	December 17, 2024	December 27, 2024
Fourth quarter	Special	$ 2.00	$ 19,495	December 17, 2024	December 27, 2024
2025					
First quarter	Quarterly	$ 1.25	$ 12,317	March 18, 2025	March 28, 2025
Second quarter	Quarterly	$ 1.25	$ 12,317	June 17, 2025	June 27, 2025
Third quarter	Quarterly	$ 1.25	$ 12,335	September 16, 2025	September 26, 2025
Fourth quarter	Quarterly	$ 1.25	$ 12,375	December 16, 2025	December 26, 2025

1. Total dividends paid does not reflect changes in dividend equivalent rights as reflected in the statement of changes in shareholders' equity.

The Company announced on March 6, 2026 that a quarterly cash dividend of $1.25 per share had been declared for the first quarter of 2026, to be paid on March 27, 2026 to shareholders of record as of the close of business on March 17, 2026.

The declaration and payment of any future dividend, whether fixed, special, or variable, will remain at the full discretion of the Company's Board of Directors and will depend upon the Company's financial position, results of operations, cash flows, capital requirements, business conditions, future expectations, the requirements of applicable law, and other factors that the Company's Board of Directors finds relevant at the time of considering any potential dividend declaration.

We have accrued liabilities for dividend equivalent payments to be made upon the vesting of restricted stock units outstanding as of the dividend record date, but not yet vested. These amounts total $1.3 million and $1.6 million as of December 31, 2025 and 2024, respectively, and are reported in current and other long-term liabilities on the consolidated balance sheets.

Warrants

Each holder of Unit common stock outstanding (Old Common Stock) before the Emergence Date that did not opt out of the release under the Plan was entitled to receive 0.03460447 warrants for every share of Old Common Stock owned. Each warrant is exercisable for one share of common stock, subject to adjustment as provided in the Warrant Agreement. The warrants expire on the earliest of (i) September 3, 2027, (ii) consummation of a Cash Sale (as defined in the Warrant Agreement), or (iii) the consummation of a liquidation, dissolution or winding up of the Company.

As of December 31, 2025, the Company had authorized 1,843,318 warrants of which 100,668 had been exercised or canceled.

Among other provisions, the Warrant Agreement outlines potential adjustments to the warrants if certain events occur, including (i) stock dividends payable in shares of common stock or stock splits, (ii) reverse stock splits or similar combination events, (iii) Liquidity Events (as defined in the Warrant Agreement), and (iv) other events not explicitly contemplated which may have an adverse impact to the intent and purpose of the warrants as set forth in the Plan, provided, however, the warrants will not be adjusted for (a) any issuances of securities in connection with a merger, share exchange, asset acquisition, stock purchase, recapitalization, reorganization or other similar business combination, (b) the issuance of any securities by Unit on or after the Emergence Date pursuant to the Plan or upon the issuance of shares of common stock upon the exercise of such securities, (c) the issuance of any shares of common stock pursuant to the exercise of the warrants, (d) the issuance of shares of common stock pursuant to any management stock option incentive or similar plan, (e) a dividend or distribution to holders of common stock of cash, property, or securities (other than common stock), and/or (f) any change in the par value of the common stock.

Pursuant to the terms of the Warrant Agreement, the Company determined the initial exercise price of the warrants to be $63.74. On April 7, 2022, the Company delivered notice of the initial exercise price to the Warrant Agent and the warrants became exercisable for shares of the Company's common stock. On or about April 25, 2022, the warrants began trading over-the-counter under the symbol "UNTCW". On March 31, 2023, the warrants began trading on the OTCQX Best Market.

See Note 19 - Commitments and Contingencies for disclosure on litigation related to the warrants.

NOTE 7 – EARNINGS PER SHARE

The table below shows the calculation of earnings per share attributable to Unit Corporation using the treasury stock method for the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands except per share amounts)	
Net Income (Numerator)		
Continuing operations	$ 41,554	$ 17,468
Discontinued operations	56,738	29,777
Total net income	$ 98,292	$ 47,245
Weighted Shares (Denominator)		
Basic shares	9,940	9,812
Effect of dilutive restricted stock units and stock options [1]	20	143
Diluted shares	9,960	9,955
Basic Earnings Per Share		
Continuing operations	$ 4.18	$ 1.78
Discontinued operations	5.71	3.03
Total basic earnings per share	$ 9.89	$ 4.82
Diluted Earnings Per Share		
Continuing operations	$ 4.17	$ 1.75
Discontinued operations	5.70	2.99
Total diluted earnings per share	$ 9.87	$ 4.75

1. The diluted earnings per share calculation excludes the effects related to 1.7 million average warrants with a $63.74 exercise price and for both periods presented because their inclusion would be antidilutive.

NOTE 8 – ACCRUED LIABILITIES

The table below presents the components of accrued liabilities:

	As of December 31,	
	2025	2024
	(In thousands)	
Employee costs	$ 5,317	$ 9,004
Lease operating expenses	2,075	2,515
Capital expenditures	4,616	3,263
Taxes	2,839	501
Interest payable	8	8
Other	212	1,081
Total accrued liabilities	$ 15,067	$ 16,372

Accrued capital expenditures as of December 31, 2024 include the accrual of $2.2 million for acreage in Oklahoma acquired in December 2024. See Note 5 - Acquisitions And Divestitures for additional information.

NOTE 9 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

The table below presents the individual components of long-term debt:

	As of December 31,	
	2025	2024
	(In thousands)	
Long-term debt:		
Second credit agreement	—	—

Second Amended and Restated Credit Agreement. On March 8, 2024, the Company entered into the Second Amended and Restated Credit Agreement (the Second Amended and Restated Credit Agreement), dated as of March 8, 2024 and effective as of March 1, 2024. This agreement replaces the Exit credit agreement, which was set to mature on March 1, 2024. The Second Amended and Restated Credit Agreement provides a $10.0 million initial borrowing base, subject to semi-annual redetermination, with BOKF, NA dba Bank of Oklahoma (BOKF). The Second Amended and Restated Credit Agreement matures on March 8, 2027 and is collateralized by the Company's upstream properties.

On September 30, 2025, the Company finalized the first amendment to the Second Amended and Restated Credit Agreement. Under the first amendment, the Company requested, and was granted, the release of UDC as a borrower under the Second Amended and Restated Credit Agreement. In addition, the first amendment to the Second Amended and Restated Credit Agreement reaffirmed the borrowing base of $10.0 million.

The Second Amended and Restated Credit Agreement requires the Company to comply with certain financial ratios, including: the Net Leverage Ratio (as defined in the Second Amended and Restated Credit Agreement) as of the last day of any fiscal quarter can not be greater than 3.00 to 1.00 and the Current Ratio to be less than 1.00 to 1.00. The Second Amended and Restated Credit Agreement also contains provisions, among others, that require the Company to provide quarterly financial statements within 45 days after the end of each of the first three quarters of each fiscal year and annual audited financial statements within 90 days after the end of each fiscal year. As of December 31, 2025, the Company was in compliance with these covenants.

As of December 31, 2025, we had no long-term borrowings and $1.1 million of letters of credit outstanding under the Second Amended and Restated Credit Agreement.

Exit Credit Agreement. On the Emergence Date, the Company entered into an amended and restated credit agreement (the Exit credit agreement), providing for a $140.0 million senior secured revolving credit facility (RBL Facility) and a $40.0 million senior secured term loan facility, among (i) the Company, UDC, and UPC (together, the Borrowers), (ii) the guarantors party thereto, including the Company and all of its subsidiaries existing as of the Emergence Date (other than Superior Pipeline Company, L.L.C. and its subsidiaries (Superior)), (iii) the lenders party thereto from time to time (Emergence Lenders), and (iv) BOKF, NA dba Bank of Oklahoma as administrative agent and collateral agent. The maturity date of borrowings under the Exit credit agreement was March 1, 2024. The Exit credit agreement was secured by first-priority liens on substantially all of the personal and real property assets of the Borrowers and the guarantors, including the Company's ownership interests in Superior.

Other Long-Term Liabilities

The table below presents the components of other long-term liabilities:

	As of December 31,	
	2025	2024
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 9,369	$ 11,214
Workers' compensation	8,838	7,685
Separation benefit plans	1,254	1,063
Gas balancing liability	3,022	3,081
Dividend equivalents liability	1,283	1,564
	23,766	24,607
Less: current portion	2,554	1,942
Total other long-term liabilities	$ 21,212	$ 22,665

NOTE 10 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities associated with the future retirement of our long-lived assets. Our asset retirement obligations (AROs) primarily relate to the plugging and abandonment of our oil and natural gas wells once the reserves are depleted or the wells can no longer produce.

The fair value of the plugging and abandonment liability is recognized when a well is drilled or acquired and the obligation is incurred. This estimation is based on current costs, applicable regulations, and our historical experience, and it incorporates assumptions about future inflation and discount rates.

None of our assets are restricted for the purpose of settling these AROs. All of our AROs relate to the plugging costs associated with our oil and gas wells. We continually review and adjust these estimates as necessary to reflect changes in regulations, technology, and market conditions.

The following table presents activity for our estimated AROs during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
ARO liability, beginning of period	$ 11,214	$ 10,901
Accretion of discount	893	800
Liability incurred	6	1
Liability settled	(584)	(201)
Liability sold	—	(127)
Revision of estimates [1]	(2,160)	(160)
ARO liability, end of period	9,369	11,214
Less: current portion	613	683
Long-term ARO liability	$ 8,756	$ 10,531

1. Plugging liability estimates were revised for updates in the cost of services used to plug wells over the preceding year and estimated dates to be plugged.

NOTE 11 – WORKERS' COMPENSATION

We are liable for workers' compensation benefits for traumatic injuries through our self-insured program to provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates.

The following table presents activity for our workers' compensation liability during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Workers' compensation liability, beginning of period	$ 7,685	$ 8,296
Claims and valuation adjustments	1,431	(296)
Payments	(278)	(315)
Workers' compensation liability, end of period	8,838	7,685
Less: current portion	1,207	766
Long-term workers' compensation liability	$ 7,631	$ 6,919

Our workers' compensation liability above is presented on a gross basis and does not include our expected receivables on our insurance policy. Our receivables for traumatic injury claims under these policies as of December 31, 2025 and 2024 are $5.8 million and $5.0 million, respectively, and are included in other assets on our consolidated balance sheets.

NOTE 12 – INCOME TAXES

During the calendar year ended December 31, 2025, the Company adopted ASU 2023-09, *Improvements to Income Tax Disclosures*, to enhance the income taxes disclosures regarding the rate reconciliation disclosure and income taxes paid by jurisdiction. The enhanced rate reconciliation is as follows:

	Year Ended December 31,			
	2025		2024	
	(In thousands)			
U.S. federal statutory tax rate	$ 8,345	21.0%	$ 4,663	21.0%
State and local income taxes, net of federal income tax effect (1)	612	1.5%	347	1.6%
Foreign tax effects	—	—	—	—
Effect of changes in tax laws or rates enacted in the current period	—	—	—	—
Effect of cross-border tax laws	—	—	—	—
Tax credits				
Federal marginal well tax credits	(7,236)	(18.2)%	—	—
Changes in valuation allowance	(2,270)	(5.7)%	(340)	(1.5)%
Nontaxable or nondeductible items				
Stock-based compensation	365	0.9%	69	0.3%
Percentage depletion	(1,728)	(4.3)%	—	—
Other	95	0.2%	(3)	(0.0)%
Changes in unrecognized tax benefits	—	—	—	—
Other adjustments	—	—	—	—
Effective tax rate	$ (1,817)	(4.6)%	$ 4,736	21.3%

1. State taxes in New Mexico, Texas, and Pennsylvania contributed to the majority of the tax effect in this category.

The income taxes paid by jurisdiction by the Company are as follows (inclusive of discontinued operations):

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Federal	$ —	$ —
State	526	1,700
Foreign	—	—
Total income taxes paid	$ 526	$ 1,700

Income taxes paid (net of refunds) exceeds 5% of total income taxes paid (net of refunds) in the following jurisdictions:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
New Mexico	$ 305	$ 771
Texas (margin tax)	230	534
Pennsylvania	—	396
Other	(9)	(1)
Total income taxes paid	$ 526	$ 1,700

The Company reviews available positive and negative evidence to assess the need for a valuation allowance against the Company's deferred tax assets. Due to a decrease in the Company's allowance for losses and nondeductible accruals recognized during the year ended December 31, 2025, the Company recognized a $2.3 million decrease in the valuation allowance associated with that deferred tax asset. The Company will continue to maintain a partial valuation allowance on its deferred tax assets related to certain non-producing oil and gas properties and allowance for losses and nondeductible accruals. The Company also recognized $0.3 million decrease in the valuation allowance during the year ended December 31, 2024.

During the second quarter of 2025, the Company finalized its calculation of the federal tax credit for oil and gas production from marginal wells for the calendar years 2020, 2021, and 2024. The calculation resulted in $5.9 million of federal tax credits recognized during the period. Due to the Company's net tax loss position for calendar years 2020 and 2021, the Company has amended its general business tax credit carryforwards for those years. The Company has estimated its 2025 calculation of the federal tax credit for oil and gas production from marginal wells to be $1.3 million. This credit was recognized in the fourth quarter of 2025.

Realizability of NOL carryforwards is dependent upon the Company's ability to produce future taxable income. Predicting future earnings is uncertain as commodity prices are volatile. As the Company continues to assess the realizability of NOL carryforwards going forward, changes in estimates of future taxable income could result in the need for a valuation allowance to be applied in future periods. As of December 31, 2025, and subject to the finalization of the Company's 2024 income tax filings, the Company has an expected federal net operating loss carryforward of $105.6 million, which is not subject to expiration. See Note 22 – Discontinued Operations for discussion of the tax impact on the sale of UDC.

On July 4, 2025, the One Big Beautiful Bill Act (OBBBA) was enacted into law. While the OBBBA included many tax changes, the bill did not have a significant impact to our financial statements.

The following table presents the Company's total provision for income taxes during the periods indicated:

	Year Ended December 31,	
	2025	**2024**
	(In thousands)	
Current taxes:		
Federal	$ —	$ —
State	4	—
	4	—
Deferred taxes:		
Federal	—	—
State	(1,821)	4,736
	(1,821)	4,736
Total provision for income taxes	$ (1,817)	$ 4,736

The following table presents the components of net deferred tax assets and liabilities (inclusive of discontinued operations):

	December 31, 2025	December 31, 2024
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 4,631	$ 7,171
Net operating loss carryforward	24,808	49,281
Non-producing oil and natural gas properties	18,699	18,699
General business credit carryforward	5,211	1,738
Gross deferred tax assets	53,349	76,889
Valuation allowance	(23,329)	(25,870)
Total deferred tax assets	30,020	51,019
Deferred tax liabilities:		
Contract drilling equipment [1]	—	(12,495)
Other equipment	(298)	(435)
Producing oil and natural gas properties	(10,545)	(5,110)
Total deferred tax liabilities	(10,843)	(18,040)
Deferred tax assets, net	$ 19,177	$ 32,979

1. See Note 22 – Discontinued Operations as it relates to the divestiture of UDC and the related net deferred tax liability.

We file income tax returns in the U.S. federal jurisdiction and various states. We are no longer subject to U.S. federal tax examinations for years before 2022 or state income tax examinations by state taxing authorities for years before 2021. As of December 31, 2025, our tax basis in UPC's properties was approximately $133.0 million.

NOTE 13 – EMPLOYEE BENEFIT PLANS

Separation Benefit Plan. The Company provides benefits to employees who are involuntarily separated through the Second Amended and Restated Separation Plan (Separation Plan). Benefits from the Separation Plan received by employees are based on salary, years of service, and level within the organization. Payments may be paid in a lump sum or installments ranging from two to 13 weeks. Under the Separation Plan, an employee vests in a 13 week severance benefit after 20 years of service provided to the Company. This amount is payable upon voluntary separation. As of December 31, 2025 and 2024, the Company had $1.3 million and $1.1 million payable for separation benefits, respectively. These amounts are included on the consolidated balance sheets in current and other long-term liabilities.

We recognized expense for benefits associated with anticipated payments from these separation plans of $2.2 million and $0.7 million during the years ended December 31, 2025 and 2024, respectively. The increase is due to the sale of UDC and benefits received by eligible employees.

401(k) Employee Thrift Plan. Employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the 401(k) Employee Thrift Plan. We may match each employee's contribution, up to a specified maximum, in full or on a partial basis with cash. The 2024 and 2025 plan year matching contributions were made in cash. Total 401(k) employer matching expense was $1.1 million and $1.2 million during the years ended December 31, 2025 and 2024, respectively.

NOTE 14 – TRANSACTIONS WITH RELATED PARTIES

Robert Anderson, a current director of the Company, also holds an executive position at GBK Corporation. GBK Corporation is a holding company with multiple subsidiaries and affiliates in the energy and industry sectors, including Kaiser Francis Oil Company and Cactus Drilling Company, L.L.C. In the ordinary course of business, the Company has made payments to Kaiser Francis Oil Company for working interests, joint interest billings, and product purchases, and has received payments for working interests and joint interest billings. See Note 5 – Acquisitions and Divestitures and Note 22 – Discontinued Operations for further discussion of the sale of our wholly-owned subsidiary, UDC, to our related party Cactus Drilling Company, L.L.C.

In conjunction with the sale, the Company provided transition services through December 31, 2025. Total fees received by the Company from Cactus Drilling Company, L.L.C. were $0.2 million.

The table below presents the payment activity with these related parties during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Payments made to:		
Kaiser Francis Oil Company	$ 4,317	$ 942
Payments received from:		
Kaiser Francis Oil Company	$ 2,697	$ 4,297
Cactus Drilling Company, L.L.C.	$ 119,725	$ —

NOTE 15 – STOCK-BASED COMPENSATION

Unit Corporation Long Term Incentive Plan. On the Emergence Date, the Board adopted the Unit Corporation Long Term Incentive Plan (LTIP) to incentivize employees, officers, directors and other service providers of the Company and its affiliates. The LTIP is administered by the Compensation Committee and provides for the grant, from time to time, at the discretion of the Board or a committee thereof, of stock options, stock appreciation rights, restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards, performance awards, substitute awards or any combination of the foregoing. Subject to adjustment in the event of certain transactions or changes of capitalization in accordance with the LTIP, 903,226 shares of New Common Stock were reserved for issuance pursuant to awards under the LTIP. New Common Stock subject to an award that expires or is canceled, forfeited, exchanged, settled in cash, or otherwise terminated without delivery of shares and shares withheld to pay the exercise price of, or to satisfy the withholding obligations with respect to, an award will again be available for delivery pursuant to other awards under the LTIP.

On July 1, 2025, 52,136 restricted stock units (RSUs) and 36,629 performance restricted stock units (PRSUs) were issued to members of the Board and certain members of management pursuant to the LTIP. Vesting for the awards ranges between one and three years and the underlying compensation will be recorded ratably over the vesting period.

The following table presents the stock-based compensation expense activity recognized during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Recognized stock compensation expense [(1)]	$ 1,763	$ 4,597
Tax benefit on stock-based compensation	$ 414	$ 1,080

1. Includes $0.2 million and $0.7 million recorded under discontinued operations for the years ended December 31, 2025 and 2024, respectively.

The tables below presents the activity pertaining to nonvested RSUs during the periods indicated:

	Year Ended December 31,					
	2025			2024		
	Number of Shares		Weighted Average Grant Date Fair Value	Number of Shares		Weighted Average Grant Date Fair Value
Nonvested RSUs, beginning of period	47,044	$	44.79	91,635	$	31.24
Granted	52,136		26.38	33,296		36.49
Vested	(39,597)		(43.43)	(71,672)		27.31
Forfeited	(7,326)		(28.63)	(6,215)		39.85
Nonvested RSUs, end of period [(1)]	52,257	$	29.73	47,044	$	44.79

1. The aggregate compensation cost related to nonvested RSUs not yet recognized as of December 31, 2025 was $1.8 million with a weighted average remaining service period of 0.9 years.

The tables below summarizes activity pertaining to outstanding stock options during the periods indicated:

	Year Ended December 31,					
	2025			2024		
	Number of Shares		Weighted Average Exercise Price	Number of Shares		Weighted Average Exercise Price
Outstanding stock options, beginning of period	153,399	$	0.50	215,298	$	7.50
Granted	—		—	—		—
Exercised	(153,399)		0.50	(55,608)		7.22
Forfeited or expired	—		—	(6,291)		7.50
Outstanding stock options, end of period	—	$	—	153,399	$	0.50
Exercisable stock options, end of period	—	$	—	153,399	$	0.50

The table below summarizes activity pertaining to PRSUs during the periods indicated:

	Year Ended December 31,					
	2025			2024		
	Number of Shares		Weighted Average Grant Date Fair Value	Number of Shares		Weighted Average Grant Date Fair Value
Nonvested PRSUs, beginning of period	29,730	$	25.24	—	$	—
Granted	36,629		17.16	29,730		25.24
Vested	—		—	—		—
Forfeited	(15,445)		(20.14)	—		—
Nonvested PRSUs, end of period [(1)]	50,914	$	20.97	29,730	$	25.24

1. The aggregate compensation cost related to nonvested PRSUs not yet recognized as of December 31, 2025 was $0.6 million with a weighted average remaining service period of 1.6 years.

Vesting of the PRSUs occurs on December 31, 2026, for the 2024 grants, and December 31, 2027, for the 2025 grants, only if the Company's total shareholder return (TSR) achieves certain performance criteria set forth in the agreement.

NOTE 16 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs, and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production subject to a derivative contract are based, in part, on our view of current and future market conditions as well as certain requirements stipulated in the Second Amended and Restated Credit Agreement. For the years ended December 31, 2025 and 2024, our commodity derivative transactions consisted of the following types of hedges:

- Basis/Differential Swaps. We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the commodity and pay or receive the published index price at the specified delivery point. We use basis/differential swaps to hedge the price risk between NYMEX and its physical delivery points.
- Swaps. We receive or pay a fixed price for the commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

We do not engage in derivative transactions for speculative purposes. We are not required to post any cash collateral with our counterparties and no collateral has been posted as of December 31, 2025.

The following non-designated hedges were outstanding as of December 31, 2025:

Remaining Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'26 - Dec'26	Natural gas - swap Floating to fixed	5,000 MMBtu/day	$4.22	IF - NYMEX (HH)
Jan'26 - Dec'26	Crude Oil - swap Floating to fixed	12,000 Bbl/month	$65.85	WTI - NYMEX

The following non-designated hedges were entered into subsequent to December 31, 2025:

Remaining Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Feb'26 - Oct'26	Natural gas - swap Floating to fixed	5,000 MMBtu/day	$4.22	IF - NYMEX (HH)
Feb'26 - Dec'26	Natural gas - swap Floating to fixed	5,000 MMBtu/day	$4.02	IF - NYMEX (HH)
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$64.40	WTI - NYMEX
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	7,000 Bbl/month	$69.10	WTI - NYMEX
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	8,000 Bbl/month	$70.50	WTI - NYMEX
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$73.75	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$65.00	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$63.90	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$62.10	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	7,000 Bbl/month	$64.70	WTI - NYMEX

The following table presents the recognized derivative assets on our consolidated balance sheets as of the date identified:

		Balances as of December 31, 2025		
	Balance Sheet Classification	Presented Gross	Effects of Netting	Presented Net
			(In thousands)	
Assets:				
Current commodity derivatives	Current derivative assets	$ 2,135	$ —	$ 2,135
Long-term commodity derivatives	Non-current derivative assets	—	—	—
Total derivative assets		$ 2,135	$ —	$ 2,135
Liabilities:				
Current commodity derivatives	Current derivative liabilities	$ —	$ —	$ —
Long-term commodity derivatives	Non-current derivative liabilities	—	—	—
Total derivative liabilities		$ —	$ —	$ —

	Balance Sheet Classification	Balances as of December 31, 2024 Presented Gross	Effects of Netting	Presented Net
			(In thousands)	
Assets:				
Current commodity derivatives	Current derivative assets	$ 1,691	$ (1,157)	$ 534
Long-term commodity derivatives	Non-current derivative assets	—	—	—
Total derivative assets		$ 1,691	$ (1,157)	$ 534
Liabilities:				
Current commodity derivatives	Current derivative liabilities	$ 1,157	$ (1,157)	$ —
Long-term commodity derivatives	Non-current derivative liabilities	—	—	—
Total derivative liabilities		$ 1,157	$ (1,157)	$ —

The following table presents the activity related to derivative instruments in the consolidated statements of operations during the periods indicated:

	Year Ended December 31, 2025	2024
	(In thousands)	
Unrealized gain on derivatives	$ 1,602	$ 534
Cash receipts on derivatives settled	7,498	—
Gain on derivatives, net	$ 9,100	$ 534

NOTE 17 – FAIR VALUE MEASUREMENTS

We have determined the estimated fair values by using market information and certain valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. Using different market assumptions or valuation methodologies may have a material effect on our estimated fair value amounts.

The inputs available determine the valuation technique that we use to measure the fair value of assets and liabilities presented in our consolidated financial statements. Fair value measurements are categorized into one of three different levels depending on the observability of the inputs used in the measurement. The levels are summarized as follows:

- Level 1—observable inputs such as quoted prices in active markets for identical assets and liabilities.
- Level 2—other observable pricing inputs, such as quoted prices in inactive markets, or other inputs that are either directly or indirectly observable as of the reporting date, including inputs that are derived from or corroborated by observable market data.
- Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data or estimates about how market participants would value such assets and liabilities.

Recurring Fair Value Measurements

The following table presents our recurring fair value measurements as of the identified date:

	Balances as of December 31, 2025			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets:				
Commodity derivative assets	$ —	$ 2,135	$ —	$ 2,135

	Balances as of December 31, 2024			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets:				
Commodity derivative assets	$ —	$ 534	$ —	$ 534

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above. There were no transfers between Level 2 and Level 3 financial liabilities.

Commodity Derivatives. We measure the fair values of our crude oil and natural gas swaps using estimated discounted cash flow calculations based on the NYMEX futures index. We consider these Level 2 measurements within the fair value hierarchy as the inputs in the model are substantially observable over the term of the commodity derivative contract and there is a wide availability of quoted market prices for similar commodity derivative contracts.

We determined that the non-performance risk regarding our commodity derivative counterparties was immaterial based on our valuation at December 31, 2025.

There were no Level 3 fair value measurements during the years ended December 31, 2025 or 2024.

Fair Value of Other Financial Instruments

We have determined the estimated fair values of other financial instruments by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair values because of their short-term nature.

Fair Value of Non-Financial Instruments

Asset Retirement Obligations (AROs). The initial measurement of AROs at fair value is calculated using discounted cash flow techniques based on internal estimates of future retirement costs associated with our property and equipment. Significant Level 3 inputs used in the calculation of AROs include plugging costs and remaining reserve lives. This process incorporates assumptions about future inflation and discount rates to estimate the fair value accurately. A summary of the Company's ARO activity is presented in Note 10 – Asset Retirement Obligations.

Stock-Based Compensation. We use the Black-Scholes option pricing model to estimate the fair value of stock option grants and modifications while the value of our restricted stock unit grants is based on the grant date closing stock price. Key assumptions for the Black-Scholes models include the stock price, exercise price, expected term, risk-free rate, volatility, and dividend yield. We consider this a Level 3 measurement within the fair value hierarchy as estimated volatility is generally unobservable and requires management's estimation.

We used a Monte Carlo simulation to estimate the fair value of the PRSU grants during the year ended December 31, 2025. Key assumptions within the model include volatility, risk-free rate, and a simulation of stock prices during the performance period. We consider these inputs to be a Level 3 measurement within the fair value hierarchy as estimated volatility and simulated stock prices are unobservable and require management's estimation.

Impairments. Non-recurring fair value measurements are also applied, when applicable, to determine the fair value of our long-lived assets and goodwill. We recorded no impairment charges during the years ended December 31, 2025 or 2024. The fair value measurement of these assets is categorized as a Level 3 measurement as the discounted cash flow models require the use of significant unobservable inputs.

NOTE 18 – LEASES

Operating Leases. We are a lessee through noncancellable lease agreements for property and equipment consisting primarily of office space, land, vehicles, and equipment used in both our operations and administrative functions.

The following table presents the maturities, weighted average remaining lease term, and the weighted average discount rate of our operating lease liabilities as of December 31, 2025:

		Amount (In thousands)
Ending December 31,		
2026	$	1,793
2027		40
2028		—
2029		—
2030		—
2031 and beyond		—
Total future payments		1,833
Less: Interest		50
Present value of future minimum operating lease payments		1,783
Less: Current portion		1,743
Total long-term operating lease payments	$	40
Weighted average remaining lease term (years)		0.8
Weighted average discount rate [1]		6.73%

1. Our weighted average discount rates represent the rate implicit in the lease or our incremental borrowing rate for a term equal to the remaining term of the lease.

The following table presents the operating and finance lease assets and liabilities on our consolidated balance sheets:

	Balance Sheet Classification	December 31, 2025	December 31, 2024
		(In thousands)	
Assets			
Operating lease right of use assets	Right of use assets	$ 1,732	$ 3,915
Total lease right of use assets		$ 1,732	$ 3,915
Liabilities			
Current liabilities:			
Operating lease liabilities	Current operating lease liabilities	$ 1,743	$ 2,436
Non-current liabilities:			
Operating lease liabilities	Operating lease liabilities	40	1,589
Total lease liabilities		$ 1,783	$ 4,025

The following table presents the components of total lease cost for our operating and finance leases during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Components of total lease cost:		
Short-term lease cost [(1)]	$ 6,642	$ 4,979
Operating lease cost	2,652	2,722
Total lease cost	$ 9,294	$ 7,701

1. Short-term lease cost includes amounts capitalized related to our oil and natural gas segment of $1.8 million and $0.4 million for the years ended December 31, 2025 and 2024, respectively.

The following table presents supplemental cash flow information related to our operating and finance leases during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Cash payments made on operating leases	$ 2,711	$ 2,727
Lease liabilities recognized in exchange for new operating lease right of use assets	$ 302	$ 1,398
Termination of lease liabilities and operating lease right of use assets	$ (46)	$ (399)

NOTE 19 – COMMITMENTS AND CONTINGENCIES

Environmental

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. We also conduct periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. Any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees expected to devote significant time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, we may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property.

Litigation

The Company is subject to litigation and claims arising in the ordinary course of business which may include environmental, health and safety matters, commercial disputes with customers, or more routine employment related claims. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. As new information becomes available or because of legal or administrative rulings in similar matters or a change in applicable law, the Company's conclusions regarding the probability of outcomes and the amount of estimated loss, if any, may change. Although we are insured against various risks, there is no assurance that the nature and amount of that insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings.

On September 11, 2023, a group of plaintiffs filed an attempted class action lawsuit alleging that during the Company's Chapter 11 bankruptcy, it changed the anti-dilution language of the approved form of warrant agreement without seeking the court's approval under section 1127(b) of the Bankruptcy Code. The case was filed in the United States Federal District Court for the Western District of Oklahoma (WDOK). On December 20, 2023, the Company filed a motion in the U.S. Bankruptcy Court for the Southern District of Texas (the Court) asking it to enter an order that requires the plaintiffs to dismiss the lawsuit in the WDOK because the claims asserted therein are barred by releases granted by the plaintiffs pursuant to the confirmation order entered by the Court in connection with the Company's Chapter 11 Cases, and an injunction enjoining the plaintiffs from bringing any action subject to those releases. On October 4, 2024, the Court entered an order denying the Company's motion for an order enforcing the confirmation order. The Company has appealed the Court's decision to the United States District Court for the Southern District of Texas. The Company also filed a motion with the WDOK asking it to stay proceedings pending the appeal. The WDOK granted the Company's motion on June 13, 2025.

In the second quarter of 2025, Anthony Reyes, a UDC employee, was fatally injured while working on one of its drilling rigs. On November 7, 2025, Kimberly Galarza individually and on behalf of the estate of Anthony Reyes, and his minor children along with Marcelo Reyes (Decedent's Father) and Natali Alonso (Decedent's Mother) filed a suit seeking damages for wrongful death in Harris County, Texas District Court. An estimate of possible loss cannot be made at this time.

Under the terms of the definitive agreement between the Company and Cactus Drilling Company, L.L.C. for the sale of UDC, the Company has retained all claims and open litigation arising prior to the close of the transaction.

NOTE 20 - CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

Our financial instruments that potentially subject us to concentrations of credit risk primarily consist of trade receivables with a variety of oil and natural gas companies. Our credit risk is considered limited due to the many customers comprising our customer base and we do not generally require collateral related to our receivables.

Using derivative instruments involves the risk that the counterparties cannot meet the financial terms of the transactions. We considered this non-performance risk regarding our counterparties and our own non-performance risk in our derivative valuation at December 31, 2025 and determined there was no material risk at that time. The fair value of the net derivative assets with Bank of Oklahoma, our only commodity derivative counterparty, was $2.1 million and $0.5 million as of December 31, 2025 and 2024, respectively.

The following table presents third-party customers that accounted for over 10% of our revenues:

	Year Ended December 31,	
	2025	2024
Southwest Energy, L.P.	17%	16%
CVR Energy, Inc.	14%	19%
Superior Midstream, L.L.C.	*	11%

* Accounted for less than 10% of revenues.

NOTE 21 – INDUSTRY SEGMENT INFORMATION

Effective September 30, 2025, the Company now reports one segment, oil and natural gas. This change is due to the divestiture of our contract drilling segment on October 1, 2025 and the strategic shift in our operations and financial results going forward.

The Company's chief operating decision maker (CODM) is the chief executive officer. The CODM uses the Company’s consolidated financial results to make key operating decisions, evaluate performance and to allocate resources. The measure of segment profit or loss utilized by the CODM is net income reported on the consolidated statements of operations. The significant expense categories and amounts are those that are reported in the Company’s consolidated statement of operations.

NOTE 22 –DISCONTINUED OPERATIONS

Certain assets and liabilities related to our contract drilling segment, mainly net working capital and certain other long-term and contingent liabilities, were not part of the sale of UDC per the terms of the definitive agreement signed on October 1, 2025. These assets and liabilities were retained by Unit Corporation on the sale date and are presented in the consolidated balance sheet as of December 31, 2025, but they are considered to be part of discontinued operations.

The following table summarizes the assets and liabilities classified as discontinued operations related to our contract drilling segment at the dates indicated:

	December 31, 2025	December 31, 2024
	(In thousands)	
Assets of discontinued operations		
Current assets:		
Accounts receivable, net	$ 844	$ 25,479
Prepaid expenses and other	97	524
Total current assets of discontinued operations	941	26,003
Property and equipment, net	—	62,967
Other assets	5,852	5,117
Total assets of discontinued operations	$ 6,793	$ 94,087
Liabilities of discontinued operations		
Current liabilities:		
Accounts payable	$ 311	$ 2,839
Accrued liabilities	508	4,921
Current portion of other long-term liabilities	1,497	766
Total current liabilities of discontinued operations	2,316	8,526
Other long-term liabilities	7,833	7,534
Deferred tax liability	—	10,879
Total liabilities of discontinued operations	$ 10,149	$ 26,939

The following table summarizes the results of operations from discontinued operations related to our contract drilling segment for the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Revenues:		
Total revenues	$ 94,302	$ 144,364
Expenses:		
Operating costs	70,658	99,655
Depreciation, depletion, and amortization	6,007	7,425
Gain on disposition of assets	(1,211)	(1,781)
Total operating expenses from discontinued operations	75,454	105,299
Other income (expense)	4	350
Gain on disposal of discontinued operations	(56,459)	—
Income from discontinued operations before taxes	75,311	39,415
Income tax expense (benefit), net		
Current	2,950	267
Deferred	15,623	9,371
Total income tax expense (benefit), net	18,573	9,638
Income from discontinued operations, net of tax	$ 56,738	$ 29,777

The sale of UDC resulted in a taxable gain of $106.5 million. The Company utilized NOLs of $104.5 million and Federal Tax Credits of $3.8 million to offset our total tax liability.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

The supplemental data presented herein reflects information for all our oil and natural gas producing activities. Our oil and gas operations are substantially all located in the United States.

Capitalized Costs

The following table presents capitalized costs related to our oil and natural gas activities:

	As of December 31,	
	2025	2024
	(In thousands)	
Proved properties	$ 191,183	$ 167,495
Unproved properties (wells in progress)	6,703	10,655
	197,886	178,150
Accumulated depreciation, depletion, amortization, and impairment	(100,689)	(92,023)
Net capitalized costs	$ 97,197	$ 86,127

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration, and Development Activities

The following table presents costs incurred related to our oil and natural gas activities during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Unproved properties acquired	$ 3,208	$ 9,717
Proved properties acquired	—	—
Exploration	—	—
Development	21,603	6,307
Total costs incurred	$ 24,811	$ 16,024

Unproved properties not subject to amortization relates to properties which are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the amortization calculation.

The following table presents results of operations for producing activities before inter-segment eliminations during the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Revenues from producing activities	$ 101,800	$ 92,902
Production costs	(29,869)	(31,890)
Depreciation, depletion, amortization, and impairment	(8,748)	(7,358)
	63,183	53,654
Income tax expense (benefit)	3	9
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 63,180	$ 53,645

The table below presents estimated quantities of proved developed oil, NGLs, and natural gas reserves and changes in net quantities of proved developed and undeveloped oil, NGLs, and natural gas reserves:

	Oil (MBbls)	NGL (MBbls)	Gas (Mcf)	Total (MBoe)
2024				
Proved developed and undeveloped reserves:				
Beginning of year	5,046	9,866	99,886	31,560
Revision of previous estimates (1)	251	(110)	(4,670)	(637)
Extensions and discoveries	62	9	3,851	713
Infill reserves in existing proved fields	8	—	61	18
Purchases of minerals in place	—	—	—	—
Production	(693)	(1,007)	(13,563)	(3,961)
Sales	(5)	—	—	(5)
Net proved reserves at December 31, 2024	4,669	8,758	85,565	27,688
Proved developed reserves, December 31, 2024	4,669	8,758	85,565	27,688
Proved undeveloped reserves, December 31, 2024	—	—	—	—
2025				
Proved developed and undeveloped reserves:				
Beginning of year	4,669	8,758	85,565	27,688
Revision of previous estimates (2)	635	1,386	26,838	6,494
Extensions and discoveries	607	429	3,662	1,646
Infill reserves in existing proved fields	264	103	886	515
Purchases of minerals in place	—	—	—	—
Production	(811)	(1,033)	(12,484)	(3,925)
Sales	—	—	—	—
Net proved reserves at December 31, 2025	5,364	9,643	104,467	32,418
Proved developed reserves, December 31, 2025	5,364	9,643	104,467	32,418
Proved undeveloped reserves, December 31, 2025	—	—	—	—

1. Revisions of previous estimates decreased primarily due to changes in the unescalated 12-month average product prices which decreased approximately 4% for oil and 19% for natural gas compared to the December 31, 2023 pricing.
2. Revisions of previous estimates increased primarily due to changes in the unescalated 12-month average product prices which decreased approximately 13% for oil and increased approximately 59% for natural gas compared to the December 31, 2024 pricing.

Estimates of oil, NGLs, and natural gas reserves require extensive judgments of reservoir engineering data. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed, the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth in this report is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static, and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves, nor of estimated future cash flows.

The standardized measure of discounted future net cash flows (SMOG) was calculated using 12-month average prices and year end costs adjusted for permanent differences that relate to existing proved oil, NGLs, and natural gas reserves. Future income tax expenses consider the statutory tax rates as currently enacted.

The following table presents the components of the standardized measure of discounted future net cash flows:

	As of December 31, 2025	As of December 31, 2024
	(In thousands)	
Future cash inflows	$ 889,354	$ 708,020
Future production costs	(458,726)	(373,337)
Future development costs	(305)	(981)
Future income tax expenses	(67,400)	(46,855)
Future net cash flows	362,923	286,847
10% annual discount for estimated timing of cash flows	(149,013)	(111,671)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 213,910	$ 175,176

The following table presents the principal sources of changes in the standardized measure of discounted future net cash flows:

	Year Ended December 31, 2025	Year Ended December 31, 2024
	(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (71,931)	$ (61,013)
Net changes in prices and production costs	10,474	(12,123)
Revisions in quantity estimates and changes in production timing	47,918	(4,628)
Extensions, discoveries, and improved recovery, less related costs	45,085	5,439
Changes in estimated future development costs	644	10
Previously estimated cost incurred during the period	—	—
Purchases of minerals in place	—	—
Sales of minerals in place	—	(16)
Accretion of discount	19,676	24,889
Net change in income taxes	(9,506)	(9,869)
Changes in timing and other	(3,626)	(4,694)
Net change	38,734	(62,005)
Beginning of year	175,176	237,181
End of year	$ 213,910	$ 175,176

Certain information concerning the assumptions used in computing SMOG and their inherent limitations are discussed below. We believe this information is essential for a proper understanding and assessment of the data presented.

The assumptions used to compute SMOG do not necessarily reflect our expectations of actual revenues to be derived from neither those reserves nor their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to difficulty inherent in predicting the future, variations from the expected production rate could result from factors outside of our control, such as unintentional delays in development, environmental concerns or changes in prices or regulatory controls. Also, the reserve valuation assumes that all reserves will be disposed of by production. However, other factors such as the sale of reserves in place could affect the amount of cash eventually realized.

The December 31, 2025 future cash flows were computed by applying the 12-month 2025 average unescalated prices of $65.34 per barrel of oil and $3.39 per Mcf of natural gas, then adjusted for price differentials, over the estimated life of each of our oil and natural gas properties. NGL pricing was estimated as a percentage of the pricing per barrel of oil. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil, NGLs, and natural gas reserves at the end of the year, based on continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the future pretax net cash flows relating to proved oil, NGLs, and natural gas reserves less the tax basis of our properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to our proved oil, NGLs, and natural gas reserves.

Care should be exercised in the use and interpretation of the above data. As production occurs over the next several years, the results shown may be significantly different as changes in production performance, petroleum prices and costs are likely to occur.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with the consolidated financial statements and related notes.

Introduction

In light of the October 1, 2025 sale of our subsidiary Unit Drilling Company and the resulting classification of UDC's results as discontinued operations as discussed below, we now operate, manage, and analyze the results of our operations through our subsidiary, UPC. UPC develops, acquires, and produces oil and natural gas properties for our own account.

We are optimizing production and converting non-producing reserves to producing with selective drilling activities. We evaluate future hedging of our production opportunistically depending on future market pricing among other factors.

Recent Developments

Sale of Unit Drilling Company

On October 1, 2025, we signed and simultaneously closed a definitive agreement to sell our wholly-owned contract drilling subsidiary UDC to Cactus Drilling Company, L.L.C., a related party, for cash consideration of $119.7 million.

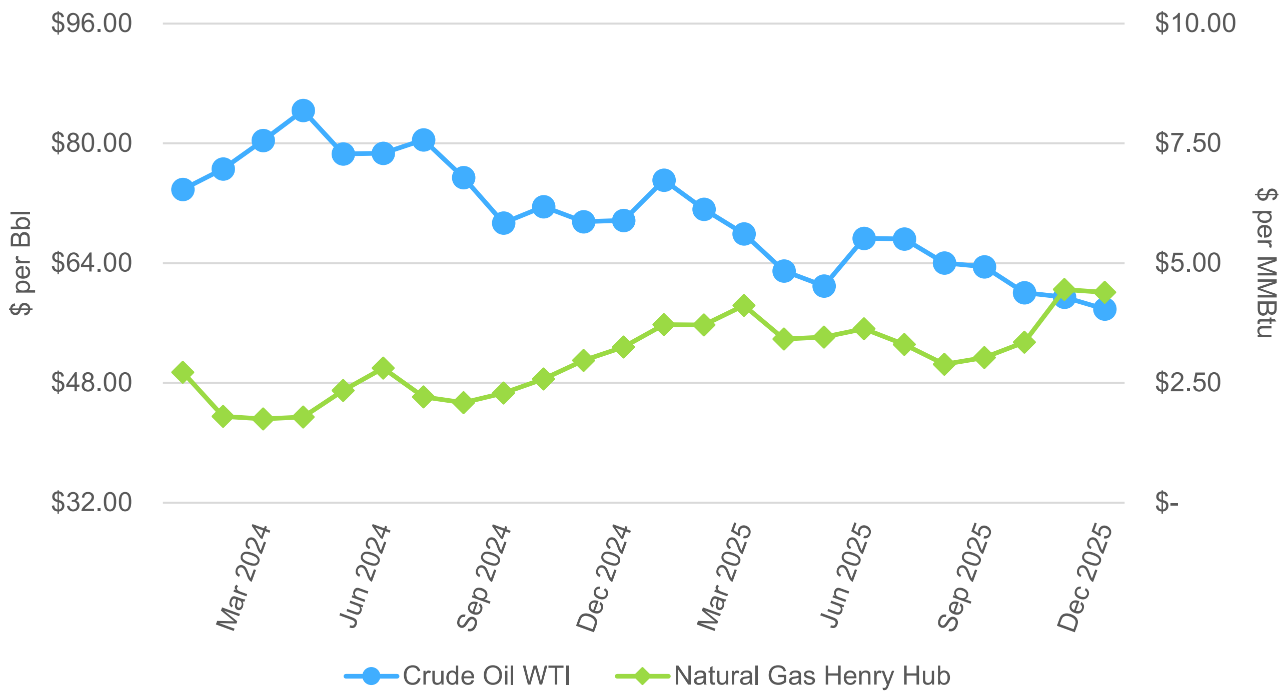
The sale of UDC will impact our operations and financial results going forward. Accordingly, the results of operations and cash flows for UDC have been classified as discontinued operations for all periods presented and prior periods have been retrospectively adjusted in the consolidated statements of operations and consolidated statements of cash flows. Our results of operations discussion below excludes discontinued operations.

See Note 14 – Transactions with Related Parties and Note 22 – Discontinued Operations for further discussion.

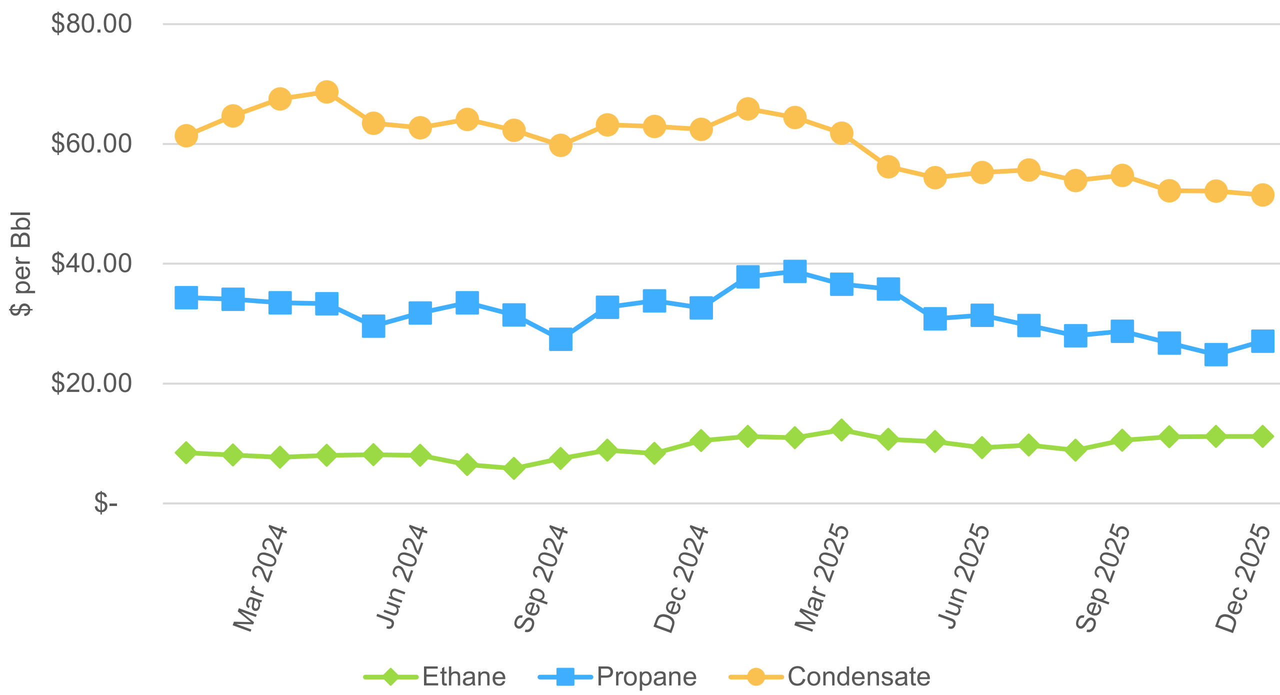
Commodity Price Environment

The prices we receive for our oil and natural gas production, the demand for oil, natural gas, and NGLs are all significant drivers of our results. While our operations are all within the United States, events outside the United States affect us and our industry, including political and economic uncertainty and geopolitical activity.

The following chart reflects the fluctuations in the historical prices for oil and natural gas:



The following chart reflects the significant fluctuations in the prices for NGLs(1):



1. NGL prices reflect the monthly average Mont Belvieu price.

Common Stock Dividends

The table below presents information about the dividends paid during the periods indicated:

	Type	Dividend per share	Total Amount	Record Date	Payment Date
2024			**(In thousands)**		
First quarter	Quarterly	$ 1.25	$ 12,269	March 18, 2024	March 28, 2024
Second quarter	Quarterly	$ 1.25	$ 12,961	June 17, 2024	June 27, 2024
Third quarter	Quarterly	$ 1.25	$ 12,248	September 16, 2024	September 27, 2024
Fourth quarter	Quarterly	$ 1.25	$ 12,185	December 17, 2024	December 27, 2024
Fourth quarter	Special	$ 2.00	$ 19,495	December 17, 2024	December 27, 2024
2025					
First quarter	Quarterly	$ 1.25	$ 12,317	March 18, 2025	March 28, 2025
Second quarter	Quarterly	$ 1.25	$ 12,317	June 17, 2025	June 27, 2025
Third quarter	Quarterly	$ 1.25	$ 12,335	September 16, 2025	September 26, 2025
Fourth quarter	Quarterly	$ 1.25	$ 12,375	December 16, 2025	December 26, 2025

The Company announced on March 6, 2026 that a quarterly cash dividend of $1.25 per share had been declared for the first quarter of 2026, to be paid on March 27, 2026 to shareholders of record as of the close of business on March 17, 2026.

The declaration and payment of any future dividend, whether fixed, special, or variable, will remain at the full discretion of the Company’s Board of Directors and will depend upon the Company’s financial position, results of operations, cash flows, capital requirements, business conditions, future expectations, the requirements of applicable law, and other factors that the Company’s Board of Directors finds relevant at the time of considering any potential dividend declaration. Future dividends are expected to be funded by cash on the Company's balance sheet.

Officer and Director Departures

On September 26, 2025, Steven B. Hildebrand informed the board that he would not stand for re-election at the 2025 annual meeting of stockholders.

Chris Menefee, former Unit Drilling Company President, had his employment terminated on October 1, 2025 in conjunction with the sale of UDC. He was eligible for benefits under the Company’s Separation Benefit Plan.

Critical Accounting Policies and Estimates

Summary

This section identifies the critical accounting policies we follow in preparing our financial statements and related disclosures. Certain policies require us to make difficult, subjective, and complex judgments while making estimates of matters inherently imprecise. Some accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or had different assumptions been used. We evaluate our estimates and assumptions regularly. We base our estimates on historical experience and various other assumptions we believe are reasonable under the circumstances, the results of which support making judgments about the carrying values of assets and liabilities not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements.

Significant Estimates and Assumptions

Full Cost Method of Accounting for Oil, NGLs, and Natural Gas Properties. Determining our oil, NGLs, and natural gas reserves is a subjective process. It entails estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. Accuracy of these estimates depends on several factors, including, the quality and availability of geological and engineering data, the precision of the interpretations of that data, and individual judgments. We hire an independent petroleum engineering firm to audit our internal evaluation of our reserves on an annual basis. The audit as of December 31, 2025 covered reserves that we projected to comprise 87% of the total proved developed future net income discounted at 10% (based on the SEC's unescalated pricing policy). The qualifications of our independent petroleum engineering firm and our employees responsible for preparing our reserve reports are included in Part C of this Annual Report.

The accuracy of estimating oil, NGLs, and natural gas reserves varies with the reserve classification and the related accumulation of available data, as shown in this table:

Type of Reserves	**Nature of Available Data**	**Degree of Accuracy**
Proved undeveloped	Data from offsetting wells, seismic data	Less accurate
Proved developed non-producing	The above and logs, core samples, well tests, pressure data	More accurate
Proved developed producing	The above and production history, pressure data over time	Most accurate

Assumptions of future oil, NGLs, and natural gas prices and operating and capital costs also play a significant role in estimating these reserves and the estimated present value of the cash flows to be received from the future production of those reserves. Volumes of recoverable reserves are influenced by the assumed prices and costs due to the economic limit (that point when the projected costs and expenses of producing recoverable oil, NGLs, and natural gas reserves are greater than the projected revenues from the oil, NGLs, and natural gas reserves). But more significantly, the estimated present value of the future cash flows from our oil, NGLs, and natural gas reserves is sensitive to prices and costs and may vary materially based on different assumptions. We use full cost accounting which factors in the unweighted arithmetic average of the commodity prices existing on the first day of each of the twelve months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements.

We compute DD&A on a units-of-production method. Each quarter, we use these formulas to compute the provision for DD&A for our producing properties:

- DD&A Rate = Unamortized Cost / End of Period Reserves Adjusted for Current Period Production
- Provision for DD&A = DD&A Rate x Current Period Production

Unamortized cost includes all capitalized costs, estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values less accumulated amortization, unproved properties, and equipment not placed in service.

Oil, NGLs, and natural gas reserve estimates have a significant impact on our DD&A rate. If future reserve estimates for a property or group of properties are revised downward, the DD&A rate will increase because of the revision. If reserve estimates are revised upward, the DD&A rate will decrease.

The DD&A expense on our oil and natural gas properties is calculated each quarter using period end reserve quantities adjusted for period production.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, we capitalize all costs incurred in the acquisition, exploration, and development of oil and natural gas properties. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to that amount which is the lower of unamortized costs or a ceiling. The ceiling is defined as the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (based on the unescalated 12-month average price on our oil, NGLs, and natural gas adjusted for any cash flow hedges), plus the cost of properties not being amortized, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is a non-cash charge reducing earnings and shareholders' equity in the period of occurrence, resulting in lower DD&A expense in future periods. A write-down cannot be reversed once incurred.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when the prices for oil, NGLs, and natural gas are depressed or if we have large downward revisions in our estimated proved oil, NGLs, and natural gas reserves. Application of these rules during periods of relatively low prices, even if temporary, increases the chance of a ceiling test write-down. As of December 31, 2025, our reserves were calculated based on applying 12-month 2025 average unescalated prices of $65.34 per barrel of oil and $3.39 per Mcf of natural gas, then adjusted for price differentials, over the estimated life of each of our oil and natural gas properties. NGL pricing was estimated as a percentage of the pricing per barrel of oil. We did not record a ceiling test write-down for the years ended December 31, 2025 or 2024.

Impairment of Other Property and Equipment. We review the carrying amounts of long-lived assets for potential impairment when events occur or changes in circumstances suggest these carrying amounts may not be recoverable. Changes that could prompt an assessment include equipment obsolescence, changes in the market demand for a specific asset, changes in commodity prices, or overall changes in general market conditions. 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 asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect our assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates, and costs. Using different estimates and assumptions could result in materially different carrying values of our assets.

Asset Retirement Obligations. We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The estimated liabilities related to these future costs are recorded at the time the wells are drilled or acquired. We use historical experience to determine the estimated plugging costs considering the well's type, depth, physical location, and ultimate productive life. A risk-adjusted discount rate and an inflation factor are applied to estimate the present value of these obligations. We depreciate the capitalized asset retirement cost and accrete the obligation over time. Revisions to the obligations and assets are recognized at the appropriate risk-adjusted discount rate with a corresponding adjustment made to the full cost pool.

Financial Condition and Liquidity

Summary

Our near-term and long-term financial condition and liquidity primarily depend on the cash flow from our operations and credit agreement borrowings. The principal factors determining our cash flow from operations are the volume of natural gas, oil, and NGLs we produce, and the prices we receive for our natural gas, oil, and NGLs production.

We currently expect that cash and cash equivalents, cash generated from operations, and available funds under our credit facility will be adequate to support our working capital, capital expenditures, dividend distributions, discretionary stock repurchases, and other cash requirements for at least the next 12 months and we are not aware of any indications that they will not be adequate for the foreseeable periods thereafter.

The table below summarizes cash flow activity for continuing and discontinued operations during the periods indicated:

	Year Ended December 31,		Percent Change (1)
	2025	2024	
	(In thousands except percentages)		
Net cash provided by operating activities	$ 91,054	$ 75,216	21%
Net cash provided by (used in) investing activities	93,492	(11,577)	NM
Net cash used in financing activities	(51,717)	(75,534)	32%
Net increase (decrease) in cash and cash equivalents	$ 132,829	$ (11,895)	

1. NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, NGLs, and natural gas production, the volume of oil, NGLs, and natural gas we produce, settlements of commodity derivative contracts. Our cash flows from operating activities are also affected by changes in working capital.

Net cash provided by operating activities during the year ended December 31, 2025 increased by $15.8 million as compared to the year ended December 31, 2024 primarily due to increased income from operations and favorable changes in net working capital.

Cash Flows from Investing Activities

We anticipate using a portion of our free cash flows for capital expenditures related to our development and production of oil, NGLs, and natural gas.

Net cash provided by (used in) investing activities increased by $105.1 million during the year ended December 31, 2025 compared to the year ended December 31, 2024 primarily due to the sale of UDC as discussed in Note 1 – Organization and Business.

Cash Flows from Financing Activities

Net cash used in financing activities decreased by $23.8 million during the year ended December 31, 2025 compared to the year ended December 31, 2024 primarily due to lower dividends paid during the year ended December 31, 2025.

As of December 31, 2025, we had unrestricted cash and cash equivalents totaling $181.7 million and no outstanding borrowings under the Second Amended and Restated Credit Agreement.

The following table summarizes certain financial condition and liquidity information as of the dates indicated:

	Year Ended December 31,	
	2025	**2024**
	(In thousands)	
Working capital	$ 172,054	$ 57,782
Current portion of long-term debt	$ —	$ —
Long-term debt	$ —	$ —
Shareholders' equity	$ 281,074	$ 232,521

Working Capital

Our working capital balance primarily fluctuates due to the increase or use of our cash and cash equivalents balances, and the timing of our trade accounts receivable and accounts payable and the fluctuation in current assets and liabilities associated with the mark to market value of our commodity derivatives. We had positive working capital of $172.1 million at December 31, 2025 compared to positive working capital of $57.8 million as of December 31, 2024. The increase in working capital is primarily due to higher cash and cash equivalents provided by the sale of UDC as discussed in Note 1 – Organization and Business.

Credit Agreements

Second Amended and Restated Credit Agreement. On March 8, 2024, the Company entered into the Second Amended and Restated Credit Agreement (the Second Amended and Restated Credit Agreement), dated as of March 8, 2024 and effective as of March 1, 2024. This agreement replaces the Exit credit agreement, which was set to mature on March 1, 2024. The Second Amended and Restated Credit Agreement provides a $10.0 million initial borrowing base, subject to semi-annual redetermination, with BOKF, NA dba Bank of Oklahoma (BOKF). The Second Amended and Restated Credit Agreement matures on March 8, 2027 and is collateralized by the Company's upstream properties.

On September 30, 2025, the Company finalized the first amendment to the Second Amended and Restated Credit Agreement. Under the first amendment, the Company requested, and was granted, the release of UDC as a borrower under the Second Amended and Restated Credit Agreement. In addition, the first amendment to the Second Amended and Restated Credit Agreement reaffirmed the borrowing base of $10.0 million.

Exit Credit Agreement. On the Emergence Date, the Company entered into an amended and restated credit agreement (the Exit credit agreement), providing for a $140.0 million senior secured revolving credit facility and a $40.0 million senior secured term loan facility, among (i) the Company, UDC, and UPC (together, the Borrowers), (ii) the guarantors party thereto, including the Company and all of its subsidiaries existing as of the Emergence Date (other than Superior and its subsidiaries), (iii) the lenders party thereto from time to time (Emergence Lenders), and (iv) BOKF, NA dba Bank of Oklahoma as administrative agent and collateral agent. The maturity date of borrowings under the Exit credit agreement was March 1, 2024. The Exit credit agreement was secured by first-priority liens on substantially all of the personal and real property assets of the Borrowers and the guarantors, including the Company's ownership interests in Superior.

Capital Requirements

Most of our capital expenditures are discretionary and directed toward growth. Our decisions to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing, which provide us flexibility in deciding when and if to incur these costs. We participated in the completion of 44 gross wells (2.18 net wells) drilled by other operators during the year ended December 31, 2025 compared to 20 gross wells (0.60 net wells) during the year ended December 31, 2024.

Oil and natural gas segment capital expenditures, including oil and gas properties on the full cost method, for the year ended December 31, 2025 totaled $25.4 million compared to $16.4 million during the year ended December 31, 2024. We had 7 gross wells (0.20 net wells) in progress as of December 31, 2025 compared to 1 gross wells (0.01 net wells) in progress as of December 31, 2024.

Net proceeds for the sale of other non-core oil and natural gas assets totaled $3.7 million and $2.9 million during the years ended December 31, 2025 and 2024, respectively. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sales did not result in a significant alteration of the full cost pool.

Derivative Activities

Commodity Derivatives. Our commodity derivatives are intended to reduce our exposure to price volatility and manage price risks. Those contracts limit the risk of downward price movements for commodities subject to derivative contracts, but they also limit increases in future revenues that would otherwise result from price movements above the contracted prices. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions.

The following non-designated commodity hedges were outstanding as of December 31, 2025:

Remaining Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'26 - Dec'26	Natural gas - swap Floating to fixed	5,000 MMBtu/day	$4.22	IF - NYMEX (HH)
Jan'26 - Dec'26	Crude Oil - swap Floating to fixed	12,000 Bbl/month	$65.85	WTI - NYMEX

As of December 31, 2025, based on our fourth quarter 2025 average daily production, the approximated percentages of our production under basis swaps are as follows:

	2026	2027 and beyond
Daily oil production	17%	—%
Daily natural gas production	15%	—%

The following non-designated commodity hedges were outstanding as of December 31, 2025:

Remaining Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Feb'26 - Oct'26	Natural gas - swap Floating to fixed	5,000 MMBtu/day	$4.22	IF - NYMEX (HH)
Feb'26 - Dec'26	Natural gas - swap Floating to fixed	5,000 MMBtu/day	$4.02	IF - NYMEX (HH)
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$64.40	WTI - NYMEX
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	7,000 Bbl/month	$69.10	WTI - NYMEX
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	8,000 Bbl/month	$70.50	WTI - NYMEX
Mar'26 - Dec'26	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$73.75	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$65.00	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$63.90	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	5,000 Bbl/month	$62.10	WTI - NYMEX
Jan'27 - Dec'27	Crude Oil - swap Floating to fixed	7,000 Bbl/month	$64.70	WTI - NYMEX

Using derivative instruments involves the risk that the counterparties cannot meet the financial terms of the transactions. We considered this non-performance risk regarding our counterparties and our own non-performance risk in our derivative valuation at December 31, 2025 and determined there was no material risk at that time. The fair value of the net derivative assets with Bank of Oklahoma, our only commodity derivative counterparty, was $2.1 million and $0.5 million as of December 31, 2025 and 2024, respectively.

Below is the effect of derivative instruments on the consolidated statements of operations for the periods indicated:

	Year Ended December 31,	
	2025	2024
	(In thousands)	
Unrealized gain on derivatives	$ 1,602	$ 534
Cash receipts on derivatives settled	7,498	—
Gain on derivatives, net	$ 9,100	$ 534

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty on our consolidated balance sheets.

Stock-Based Compensation

During the year ended December 31, 2025, we granted 52,136 restricted stock units (RSUs) with an aggregate grant date fair value of $1.4 million. The RSU grants were made in July 2025 and vest equally each year for three years. We also granted 36,629 performance restricted stock units (PRSUs) with an aggregate grant date fair value of $0.6 million. The PRSU grants were made in July 2025 and vest on December 31, 2027.

During the year ended December 31, 2024, we granted 33,296 restricted stock units (RSUs) with an aggregate grant date fair value of $1.2 million. The RSU grants were made in July 2024 and vest equally each month for 36 months. We also granted 29,730 performance restricted stock units (PRSUs) with an aggregate grant date fair value of $0.8 million. The PRSU grants were made in July 2024 and vest on December 31, 2026.

We recognized stock-based compensation expense of $1.8 million and $4.6 million during the years ended December 31, 2025 and 2024, respectively.

Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from zero to $1.0 million. We have purchased stop-loss coverage to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. There is no assurance that the insurance coverage we have will protect us against liability from all potential consequences. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles, or any combination of these rather than pay higher premiums.

Subsequent to December 31, 2025, we elected to cease self-insurance for workers' compensation, control of well, and employee medical benefits and switched to premium based plans.

Results of Operations

Year Ended December 31, 2025 versus Year Ended December 31, 2024

	Year Ended December 31,			
	2025	2024	Change	Percent Change (1)
	(In thousands unless otherwise specified)			
Net income from continuing operations	$ 41,554	$ 17,468	$ 24,086	138%
Revenues	$ 102,283	$ 93,248	$ 9,035	10%
Operating costs	$ 42,851	$ 44,420	$ (1,569)	(4)%
Average oil price ($/Bbl)	$ 64.25	$ 74.51	$ (10.26)	(14)%
Average oil price excluding derivatives ($/Bbl)	$ 63.40	$ 74.51	$ (11.11)	(15)%
Average NGLs price ($/Bbl)	$ 18.64	$ 19.71	$ (1.07)	(5)%
Average NGLs price excluding derivatives ($/Bbl)	$ 18.64	$ 19.71	$ (1.07)	(5)%
Average natural gas price ($/Mcf)	$ 3.04	$ 1.58	$ 1.46	92%
Average natural gas price excluding derivatives ($/Mcf)	$ 2.49	$ 1.58	$ 0.91	58%
Oil production (MBbls)	811	693	118	17%
NGL production (MBbls)	1,033	1,007	26	3%
Natural gas production (MMcf)	12,484	13,563	(1,079)	(8)%
Total production (MBOE)	3,925	3,961	(35)	(1)%
General and administrative expense	$ 22,406	$ 22,497	$ (91)	(0)%
Other income (expense):				
Interest income	$ 3,619	$ 4,104	$ (485)	(12)%
Interest expense	$ (34)	$ (55)	$ 21	(38)%
Gain on derivatives, net	$ 9,100	$ 534	$ 8,566	NM
Income tax expense (benefit), net	$ (1,817)	$ 4,736	$ (6,553)	(138)%

1. NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

Revenues

Oil and natural gas revenues increased $9.0 million or 10% during the year ended December 31, 2025 compared to the year ended December 31, 2024. This increase was primarily due to higher price realizations for natural gas, partially offset by lower price realizations for oil and NGLs. Excluding derivatives settled, average oil prices decreased 15% to $63.40 per barrel, average natural gas prices increased 58% to $2.49 per Mcf, and NGLs prices decreased 5% to $18.64 per barrel.

Operating Costs

Oil and natural gas operating costs decreased $1.6 million or 4% during the year ended December 31, 2025 compared to the year ended December 31, 2024. This decrease was primarily due to lower employee costs in our upstream operations.

General and Administrative

Corporate general and administrative expenses during the year ended December 31, 2025 were consistent with the year ended December 31, 2024. This was due to higher bonus and separation expenses offset by lower stock-based compensation.

Interest Income

Interest income decreased $0.5 million during the year ended December 31, 2025 compared to the year ended December 31, 2024 primarily due to lower average interest rates partially offset by higher average cash and cash equivalents.

Interest Expense

Changes in interest expense between the comparative year ended 2025 and 2024 are primarily related to commitment fees paid on the unused portion of the Second credit facility and the Exit credit facility. There were no borrowings outstanding on either credit facility during the comparative years.

Gain on Derivatives

The $8.6 million favorable change in gain on derivatives between the comparative years ended December 31, 2025 and 2024 is primarily due to timing of market pricing changes on outstanding commodity derivative positions and increased commodity derivative activity in 2025.

Income Tax Expense (Benefit), Net

The $6.6 million favorable change in income tax expense (benefit), net during the year ended December 31, 2025 compared to the year ended December 31, 2024 is primarily due to the increase in our general business tax credit carryover of $5.9 million as a result of the recognition of the federal marginal well tax credit for 2020, 2021, and 2024 and estimated calculation of the federal marginal well credit for 2025 of $1.3 million. Additionally, the $2.5 million decrease in our valuation allowance for 2025 contributed to the favorable change to a lesser extent.

Effects of Inflation

The effect of inflation in the oil and natural gas industry is primarily driven by the prices for oil, NGLs, and natural gas, as well as inflationary factors in the general United States economy. Increases in oil and gas prices increase the demand for contract drilling rigs and services. This increase in demand affects the dayrates we pay for contract drilling services. If commodity prices increase substantially for a long period, shortages in support equipment (like drill pipe, third party services, and qualified labor) can cause additional increases in material and labor costs. How inflation will affect us in the future will depend on increases, if any, in drilling rig rates, and the prices we receive for our oil, NGLs, and natural gas.

Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. Those prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, these prices have fluctuated, and they will likely continue to do so. Based on our production for the year ended December 31, 2025, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $0.1 million per month ($1.3 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of derivatives, would result in a $0.1 million per month ($0.7 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs price, without the effect of derivatives, would result in a $0.1 million per month ($1.0 million annualized) change in our pre-tax operating cash flow.

We use derivative transactions to manage the risk associated with price volatility. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

See Note 16 - Derivatives for additional information.

Interest Rate Risk. Our interest rate exposure primarily relates to our cash equivalents held in money market funds comprised of U.S. Government and U.S. Treasury securities and our long-term debt under our credit agreement. Our money market fund holdings accrue interest at variable interest rates. Based on our average cash equivalents subject to a variable rate during 2025, a 1% change in the average effective interest rate on these holdings during 2025 would change our annual pre-tax cash flow by approximately $0.9 million. Borrowings under our Second credit agreement also bear interest at variable interest rates. We had no outstanding borrowings under this facility as of December 31, 2025.

Part E. Issuance History

The following table presents all shares or any other securities or options to acquire such securities issued for services during the periods indicated below:

Month of Issuance	Issuance Type	Shares Issued	Price at Issuance	Issuance Class
2024				
July 2024	Restricted Stock Units	33,296	$ 36.49	Board and Employee
July 2024	Performance Restricted Stock Units	29,730	$ 25.24	Employee
2025				
July 2025	Restricted Stock Units	52,136	$ 26.38	Board and Employee
July 2025	Performance Restricted Stock Units	36,629	$ 17.16	Employee

All awards related to common stock were issued pursuant to the Company’s LTIP. Restricted stock unit award agreements contain language which states that the shares have not been registered under the Securities Act or any state securities laws and setting forth or referring to the restrictions on transferability and sale of the shares under the Securities Act. See Note 15 – Stock-Based Compensation for additional details.

Part F. Exhibits

2.1	Debtors' Amended Joint Chapter 11 Plan of Reorganization [Docket No. 320] (filed as Exhibit 2.1 to Unit's Form 8-K, dated August 12, 2020, which is incorporated by reference herein).
3.1	Amended and Restated Certificate of Incorporation of Unit Corporation, dated as of September 3, 2020 (filed as Exhibit 3.1 to Unit's Form 10-Q, dated August 16, 2021, which is incorporated by reference herein).
3.2	Amended and Restated Bylaws of Unit Corporation, dated as of September 3, 2020 (filed as Exhibit 3.2 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein)
10.1†	Unit Corporation Long Term Incentive Plan (filed as Exhibit 10.1 to Unit’s Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.2†	Form of Stock Option Grant Notice and Award Agreement (filed as Exhibit 10.3 to Unit’s Form 10-Q, dated November 12, 2021, which is incorporated by reference herein).
10.3†	Form of Restricted Stock Unit (RSU) Grant Notice and Award Agreement (filed as Exhibit 10.2 to Unit’s Form 10-Q, dated May 12, 2021, which is incorporated by reference herein).
10.4	Form of Indemnification Agreement between Unit Corporation and its executive officers and directors (filed as Exhibit 10.27 to Unit’s Form 10-K, dated March 31, 2021, which is incorporated by reference herein).
10.5	Form of Director Engagement Letter (filed as Exhibit 10.28 to Unit’s Form 10-K, dated March 31, 2021, which is incorporated by reference herein).
10.6	Warrant Agreement, dated as of September 3, 2020, by and between Unit Corporation and American Stock Transfer & Trust Company, LLC (filed as Exhibit 10.2 to Unit’s Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.7	Registration Rights Agreement, dated as of September 9, 2020, by and between the Company and the holders party thereto (filed as Exhibit 10.3 to Unit’s Form 8-K, dated September 10, 2020, which is incorporated by reference herein).

10.8	Second Amended and Restated Credit Agreement, dated March 8, 2024, effective March 1, 2024 (filed as Exhibit 8.2 to Unit's Quarterly Report, dated November 6, 2025, which is incorporated by reference herin).
10.9†	Performance Restricted Stock Unit Grant Notice (filed as Exhibit 10.26 to Unit's Annual Report, dated March 13, 2025, which is incorporated by reference herein).
10.10	On October 1, 2025, the Company entered into a Membership Interest Purchase Agreement (Agreement) with Cactus Drilling Company, L.L.C. (Cactus) to sell 100% of its ownership interest of its wholly-owned subsidiary, Unit Drilling Company, for cash consideration of $120.0 million, subject to customary adjustments. The Agreement includes customary representations, warranties, and covenants of the parties, as well as standard conditions to closing, termination provisions, and indemnification obligations. The Agreement also contains other terms and conditions typical for transactions of this nature.
10.11†	Second Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries – Employee benefit plan establishing severance and separation benefits for eligible employees of Unit Corporation and participating subsidiaries upon qualifying termination of employment, subject to eligibility conditions and execution of a separation and release agreement. The plan sets forth benefit eligibility, calculation of separation benefits for different employee categories, payment methods, administrative procedures, and other terms governing the provision of such benefits under ERISA.
31.1	Certification of Principal Executive Officer (filed herewith).
31.2	Certification of Principal Financial Officer (filed herewith).
99.1	Ryder Scott Company, L.P. Summary Report (filed herewith).

† Indicates a management contract or compensatory plan.

Exhibit 31.1 Certification of Principal Executive Officer

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

I, Phil Frohlich, Chief Executive Officer of Unit Corporation, certify that:

1. I have reviewed this Annual Report of Unit Corporation;

2. Based on my knowledge, this Annual 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 periods covered by this Annual Report; and

3. Based on my knowledge, the financial statements, and other financial information included or incorporated by reference in this Annual Report, fairly present in all material respects the financial condition, results of operations, and cash flows of the issuer as of, and for, the periods presented in this Annual Report.

/s/ Phil Frohlich
Phil Frohlich
Chief Executive Officer

Date: March 12, 2026

Exhibit 31.2 Certification of Principal Financial Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

I, Thomas D. Sell, Chief Financial Officer of Unit Corporation, certify that:

1. I have reviewed this Annual Report of Unit Corporation;

2. Based on my knowledge, this Annual 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 periods covered by this Annual Report; and

3. Based on my knowledge, the financial statements, and other financial information included or incorporated by reference in this Annual Report, fairly present in all material respects the financial condition, results of operations, and cash flows of the issuer as of, and for, the periods presented in this Annual Report.

/s/ Thomas D. Sell
Thomas D. Sell
Chief Financial Officer

Date: March 12, 2026

UNIT CORPORATION

Estimated

Net Future Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2025

/s/ Robert J. Paradiso

Robert J. Paradiso, P.E.
TBPELS License No. 111861
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 26, 2026

Unit Corporation
8200 South Unit Drive
Tulsa, Oklahoma 74132

Ladies and Gentlemen:

At the request of Unit Corporation (Unit), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2025 prepared by Unit's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 26, 2025 and presented herein, was prepared for public disclosure by Unit in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Unit's estimated net reserves attributable to the leasehold interests in certain properties owned by Unit and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2025. The properties reviewed by Ryder Scott incorporate 326 reserves determinations and are located in the states of North Dakota, Oklahoma and Texas. The wells for which estimates of reserves were audited by Ryder Scott were selected by Unit. At Unit's request, the reserves audit conducted by Ryder Scott addresses only the proved developed producing reserves.

The properties reviewed by Ryder Scott account for a portion of Unit's total net proved liquid hydrocarbon and gas reserves as of December 31, 2025. Based on the estimates of total net proved reserves prepared by Unit, the reserves audit conducted by Ryder Scott addresses approximately 83 percent of the total proved net reserves of Unit on a barrel of oil equivalent, BOE basis as of December 31, 2025.

The properties reviewed by Ryder Scott account for a portion of Unit's total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2025. Based on the reserves and income projections prepared by Unit, the audit conducted by Ryder Scott addresses approximately 87 percent of the total proved discounted future net income at 10% of Unit as of December 31, 2025.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Unit, it is our opinion that the overall procedures and methodologies utilized by Unit in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Unit are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Unit has informed us that in the preparation of their reserves and income projections, as of December 31, 2025, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Unit has informed us they do not have any fixed price contractual arrangements. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Unit attributable to Unit's interest in properties that we reviewed and for those that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests of
Unit Corporation
As of December 31, 2025

	Total Proved Developed Producing
Net Reserves of Properties Audited by Ryder Scott	
Oil/Condensate – MBarrels	4,749
Plant Products – MBarrels	8,211
Gas – MMcf	83,693
MBOE	26,908
Net Reserves of Properties Not Audited by Ryder Scott	
Oil/Condensate – MBarrels	616
Plant Products – MBarrels	1,432
Gas – MMcf	20,774
MBOE	5,510
Total Net Reserves	
Oil/Condensate – MBarrels	5,364
Plant Products – MBarrels	9,643
Gas – MMcf	104,467
MBOE	32,418

Values may not sum to total due to rounding.

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. No proved developed non-producing or undeveloped reserves are included herein.

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.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Unit's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

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." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves prepared by Unit for the properties that we reviewed were estimated by performance and analogy methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through October 2025 in those cases where such data were considered to be definitive. In certain cases, producing reserves were estimated by analogy. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate. The data used in these analyses were furnished to Ryder Scott by Unit or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Unit relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Unit for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2025 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used by Unit for the geographic area reviewed by us. The price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used by Unit to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used by Unit were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Unit.

The table below summarizes Unit's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Unit's "average realized prices." The average realized prices shown in the table below were determined from Unit's estimate of the total future gross revenue before production taxes for the properties reviewed by us and Unit's estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for the geographic area reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$65.34/bbl	$65.28/bbl
	NGLs	WTI Cushing	$65.34/bbl	$22.76/bbl
	Gas	Henry Hub	$3.39/MMBTU	$3.06/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Unit's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Unit are based on the operating expense reports of Unit and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Transportation fees are included as operating cost deductions. The operating costs furnished by Unit were accepted as factual data and reviewed by us for their reasonableness using information provided by Unit; however, we have not conducted an independent verification of the data used by Unit. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Unit has informed us that abandonment costs are reported outside of this report; therefore, their projection of future net income associated with the reserve projections does not reflect abandonment costs.

Current costs used by Unit were held constant throughout the life of the properties.

Unit's forecasts of future production rates are based on historical performance. If no production decline trend has been established, future production rates were held constant until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

The future production rates may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Unit's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and 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 proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Unit owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Unit for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Unit are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Unit has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Unit's forecast of future proved production, we have relied upon data furnished by Unit with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, product prices based on the SEC regulations, adjustments or differentials to product prices, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Unit. We consider the factual data furnished to us by Unit to be appropriate and sufficient for the purpose of our review of Unit's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Unit and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Unit, it is our opinion that the overall procedures and methodologies utilized by Unit in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Unit are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Unit in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Unit's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Unit's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Unit when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Unit.

Other Properties

Other properties, as used herein, are those properties of Unit which we did not review. The proved net reserves attributable to the other properties account for approximately 17 percent of the total proved net liquid hydrocarbon and gas reserves of Unit on a barrel of oil equivalent, BOE basis, based on estimates prepared by Unit as of December 31, 2025. The other properties represent approximately 13 percent of the total proved discounted future net income at 10% based on the unescalated pricing policy of the SEC as taken from reserves and income projections prepared by Unit as of December 31, 2025.

The same technical personnel of Unit were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Unit. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Unit.

We have provided Unit with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Unit and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Robert J. Paradiso

Robert J. Paradiso, P.E.
TBPELS License No. 111861
Senior Vice President **[SEAL]**

RJP (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Robert J. Paradiso was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Paradiso, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2008, is a Senior Vice President and also serves as Project Coordinator, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Paradiso served in a number of engineering positions with Getty Oil Company, Texaco, Union Texas Petroleum, Amax Oil and Gas, Inc., Norcen Explorer, Inc., Amerac Energy Corporation, Halliburton Energy Services, Santa Fe Snyder Corp., and Devon Energy Corporation. For more information regarding Mr. Paradiso's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees.

Mr. Paradiso earned a Bachelor of Science degree in Petroleum Engineering from Texas Tech University in 1979, and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Paradiso fulfills. As part of his 2025 continuing education hours, Mr. Paradiso attended 6 hours of formalized training during the 2025 RSC Reserves Conference relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Paradiso attended an additional 20¾ hours of formalized in-house training during 2025 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, SEC comment letters, carbon storage, geothermal energy, reservoir engineering, geoscience and petroleum economics evaluation methods and procedures, and ethics for consultants.

Based on his educational background, professional training and more than 46 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Paradiso has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

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. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are 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
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
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
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.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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.