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

FORM 10-K

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

For the fiscal year ended December 31, 2022

OR

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

For the transition period from to

Commission file number: 1-9260

Unit Corporation

UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware				**73-1283193**
(State or other jurisdiction of incorporation or organization)				**(I.R.S. Employer Identification No.)**
8200 South Unit Drive,	**Tulsa,**	**Oklahoma**	**US**	**74132**
(Address of principal executive offices)				**(Zip Code)**

(Registrant's telephone number, including area code) (918) 493-7700

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

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

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

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

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

* Effective January 1, 2021, the registrant's obligations to file reports under Section 15(d) of the Exchange Act were automatically suspended.

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer X

Smaller reporting company X Emerging growth company ☐

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

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

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes X No ☐

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

As of June 30, 2022, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the OTC Pink on June 30, 2022) held by non-affiliates was approximately $328.8 million. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.

As of March 17, 2023, 9,634,956 shares of the registrant's common stock were outstanding.

FORM 10-K
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).

LIBOR – London Interbank Offered Rate.

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.

BOSS Rig – Unit's proprietary BOSS rig design are Tier 1, Super-Spec alternating current drilling rigs which are standard equipped to handle multi-well pad drilling programs. Features include multi-directional walking systems, 800,000 pound static hook load masts, pipe racking capacities ranging from 22,500 to 26,500 feet, 7,500 psi mud systems, including quintuplex mud pumps, AC draw works, power generating system with dual fuel capability or high line power capability, high-torque top drives, automated iron roughneck wrenches, and automated catwalks.

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 UDC, UPC, 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.

MSA – The Amended and Restated Master Services and Operating Agreement for Superior.

New Common Stock – The Company common stock 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 Effective Date.

SCR Rig – Direct current electric rigs that are standard equipped to drill multi-well pad drilling programs. Features include 1,500 horsepower hoisting capability, 7,500 psi mud systems, top drives, iron roughnecks, and automated catwalks. These rigs are equipped with either skidding or walking systems to move from well to well on a pad.

Superior – Superior Pipeline Company, L.L.C., and its subsidiaries.

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENTS

This report contains "forward-looking statements" – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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. Forward-looking statements often contain words such as "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts," and similar expressions. This report modifies and supersedes documents filed by us before this report. Also, certain information we file with the SEC will automatically update and supersede information in this report.

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 plans to maintain or increase the 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;
- the number of gathering systems and processing plants our mid-stream investment may plan to construct or acquire;
- volumes and prices for the natural gas our mid-stream investment gathers and processes;
- expansion and growth of our business and operations;
- demand for our drilling rigs and the rates we charge for the rigs;
- 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;
- our mid-stream investment's ability to transport or convey our oil, NGLs, or natural gas production to existing pipeline systems;
- 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 our oil and natural gas segment plans 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;
- the availability and nature of (or lack of) business opportunities we pursue;
- demand for our land drilling services;
- changes in laws and regulations;
- changes in the current geopolitical situation, such as the current conflict occurring between Russia and Ukraine;
- 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, such as COVID-19; and
- other factors, most of which are beyond our control.

You should not construe this list to be exhaustive. 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.

Additional discussion of factors that may affect our forward-looking statements appear elsewhere in this report, including in Item 1A "Risk Factors," Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 7A "Quantitative and Qualitative Disclosures About Market Risk-Energy Commodity Market Risk."

UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2022

PART I

Item 1. Business

Unless otherwise indicated or required by the context, the terms "Company," "Unit," "us," "our," "we," and "its" refer to Unit Corporation or, as appropriate, one or more of its subsidiaries. References to our mid-Stream segment refer to Superior Pipeline Company, L.L.C. (and its subsidiaries) of which we own 50%.

Our executive offices are at 8200 South Unit Drive, Tulsa, Oklahoma 74132; our telephone number is (918) 493-7700.

Information regarding our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports, will be provided free in print to any shareholders who request them. They are also available on our website at *www.unitcorp.com*, as soon as reasonably possible after we electronically file these reports with or furnish them to the SEC. The SEC maintains a website at *www.sec.gov* that contains reports, proxy and information statements, and other information about us we file electronically with the SEC.

Our corporate governance guidelines and code of ethics are available for free on our website at *www.unitcorp.com* or in print to any shareholder who requests them. We may occasionally provide important disclosures to investors by posting them in the investor information section of our website, as allowed by SEC rules.

GENERAL

We were founded in 1963 as an oil and natural gas contract drilling company and have since grown to include operations in exploration and production as well as investments in mid-stream. We operate, manage, and analyze our results of operations through our three principal business segments:

- *Oil and Natural Gas* – carried out by our subsidiary Unit Petroleum Company. This segment produces, develops, and acquires oil and natural gas properties for our account.
- *Contract Drilling* – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for third parties and for our oil and natural gas segment.
- *Mid-Stream* – carried out by Superior and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas and NGLs for third parties and for our own account. We hold a 50% investment in Superior.

Each company may conduct operations through subsidiaries of its own. We also have several other subsidiaries, none of which conduct material operations.

The following table below certain information about our consolidated oil and natural gas and contract drilling assets as well as Superior's assets as of December 31, 2022:

Oil and Natural Gas	
Total number of wells in which we own an interest	4,248
Contract Drilling	
Total number of drilling rigs available for use	18
Mid-Stream	
Number of natural gas treatment plants owned by Superior	3
Number of processing plants owned by Superior	12
Number of natural gas gathering systems owned by Superior	18

2022 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

- Revenues before eliminations increased by 20% from 2021 primarily due to higher average commodity pricing, partially offset by lower production volumes.
- Operating costs before eliminations increased 13% from 2021 primarily due to higher production tax expenses due to increased revenues, higher employee compensation and separation benefits, and higher lease operating expenses.
- Capital expenditures increased 19% from 2021 as we participated in the completion of 27 gross wells (1.34 net wells) drilled by other operators.

Contract Drilling

- Revenues increased 94% from 2021 primarily due to a 50% increase in the average number of drilling rigs in use to 16.4 during the year ended December 31, 2022 as well as increases to the average dayrates on daywork contracts of 23% and 39% on BOSS rigs and SCR rigs, respectively.
- Operating costs increased 73% from 2021 primarily due to an increase in the average number of operating rigs, higher employees compensation, and $6.7 million of transportation and start up costs associated with bringing stacked rigs back into service.
- Capital expenditures increased 287% from 2021 primarily due to an increase in the average number of operating rigs.

Mid-Stream

- We consolidated the financial position, operating results, and cash flows of Superior prior to March 1, 2022, on which date the Master Services and Operating Agreement (MSA) was amended and restated, with the result that we no longer consolidate Superior's financial position, operating results, and cash flows during periods subsequent to March 1, 2022. We subsequently account for our investment in Superior as an equity method investment.
- Superior paid $9.5 million of distributions to Unit and $50.2 million of distributions to its other members during the year ended December 31, 2022, and subsequently paid distributions to SP Investor of $11.1 million in January 2023 which reduced the remaining Drilling Commitment Adjustment Amount to $20.9 million.
- On February 21, 2023, we entered into a letter agreement (the "Letter Agreement") with SP Investor under which the Company has agreed to sell all of its 50% ownership interest in Superior for $20.0 million. The Letter Agreement provides that SP Investor will pay Unit $12.0 million at closing and $8.0 million in deferred proceeds to be paid no later than 12 months from closing, subject to Unit's satisfaction of certain ongoing covenant obligations and other customary conditions.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 22 - Industry Segment Information of our Notes to Consolidated Financial Statements in Item 8 of this report for information about each of our segments' revenues, profits or losses, and total assets.

OIL AND NATURAL GAS

General. Our producing oil and natural gas properties, unproved properties, and related assets are primarily located in Oklahoma and Texas in addition to Arkansas, Kansas, and North Dakota to a lesser extent. All of our oil and natural gas properties are located in the United States.

When we are the operator of a property, we may use one of our drilling rigs to drill wells on the property and/or we may engage with our mid-stream investment to gather our gas if it is economical to do so.

The following table presents information regarding our oil and natural gas assets as of December 31, 2022 and production activity during the year then ended:

	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2022 Average Net Daily Production		
					Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
Total	4,248	1,347	15	0.68	66,332	3,510	5,885

Dispositions. The Company initiated an asset divestiture program at the beginning of 2021 to sell certain non-core oil and gas properties and reserves (the Divestiture Program). On October 4, 2021, the Company announced that it was expanding the Divestiture Program to include the potential sale of additional properties, including up to all of UPC's oil and gas properties and reserves, and on January 20, 2022, the Company announced that it had retained a financial advisor and launched the process. On June 10, 2022, the Company announced that it had ended its engagement with the financial advisor and terminated the process. During the process, the Company entered into an agreement to sell its Texas Gulf Coast oil and gas properties.

On July 1, 2022, the Company closed on the sale of certain wells and related leases near the Texas Gulf Coast for cash proceeds of $45.4 million, net of customary closing and post-closing adjustments based on an effective date of April 1, 2022. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On March 8, 2022, the Company closed on the sale of certain non-core wells and related leases located near the Oklahoma Panhandle for cash proceeds of $3.6 million, net of customary closing and post-closing adjustments based on an effective date of December 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On August 16, 2021, the Company closed on the sale of substantially all of our wells and related leases located near Oklahoma City, Oklahoma for cash proceeds of $16.1 million, net of customary closing and post-closing adjustments based on an effective date of August 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On May 6, 2021, the Company closed on the sale of substantially all of our wells and the leases related thereto located in Reno and Stafford Counties, Kansas for cash proceeds of $7.3 million, net of customary closing and post-closing adjustments based on an effective date of February 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

Net proceeds for the sale of other non-core oil and natural gas assets totaled $7.7 million and $5.0 million during the twelve months ended December 31, 2022 and 2021, 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 tables present information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31,			
	2022		2021	
	Gross	Net	Gross	Net
Wells drilled:				
Development:				
Oil	3	0.1	10	3.7
Natural Gas	4	0.2	—	—
Dry	—	—	—	—
Total development	7	0.3	10	3.7
Exploratory:				
Oil	16	0.9	13	0.7
Natural gas	4	0.2	—	—
Dry	—	—	1	—
Total exploratory	20	1.1	14	0.7
Total wells drilled	27	1.3	24	4.4

	Year Ended December 31,			
	2022		2021	
	Gross	Net	Gross	Net
Wells producing or capable of producing:				
Oil	624	126.7	736	141.2
Natural gas	2,217	686.8	2,380	649.0
Total	2,841	813.4	3,116	790.2

We did not develop any previously booked proved undeveloped oil and natural gas reserves in 2022 or 2021.

The following table presents our leasehold acreage at December 31, 2022:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net [1]	Gross	Net
Total leasehold acreage	444,575	203,440	3,617	916	448,192	204,356

1. Approximately 100% of the net undeveloped acres are covered by leases that will expire in the years 2023—2026 unless drilling or production extends those leases.

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

	Year Ended December 31,	
	2022	2021
Average sales price per barrel of oil produced:		
Price before derivatives	$ 94.28	$ 66.50
Effect of derivatives	(36.80)	(16.47)
Price including derivatives	$ 57.48	$ 50.03
Average sales price per barrel of NGLs produced:		
Price before derivatives	$ 30.00	$ 23.41
Effect of derivatives	—	—
Price including derivatives	$ 30.00	$ 23.41
Average sales price per Mcf of natural gas produced:		
Price before derivatives	$ 5.79	$ 3.55
Effect of derivatives	(2.14)	(0.62)
Price including derivatives	$ 3.65	$ 2.93

	Year Ended December 31,	
	2022	2021
Oil production (MBbls):		
Anadarko basin	1,209	1,459
Western Gulf basin	55	134
All other basins	17	22
Total oil production	1,281	1,615
NGLs production (MBbls):		
Anadarko basin	1,960	2,174
Western Gulf basin	184	445
All other basins	4	5
Total NGL production	2,148	2,624
Natural gas production (MMcf):		
Anadarko basin	21,696	22,836
Western Gulf basin	2,425	6,075
All other basins	90	101
Total natural gas production	24,211	29,012
Total production (MBoe):		
Anadarko basin	6,785	7,439
Western Gulf basin	643	1,592
All other basins	36	44
Total BOE production	7,464	9,074

The Anadarko basin contained 98% and 89% of our total proved reserves as of December 31, 2022 and 2021 respectively, 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:

	Year Ended December 31, 2022			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Total proved developed	7,681	20,132	212,409	63,215
Total proved undeveloped	—	—	—	—
Total proved	7,681	20,132	212,409	63,215

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.

Responsibility for overseeing the preparation of our reserve report is shared by our reservoir engineers Derek Smith and Troy Pickens.

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 given the responsibility of managing the Corporate Reserves. He has been a member of SPE since 2000 and joined the SPEE in 2018.

Mr. Pickens earned a Bachelor of Science degree in Mechanical Engineering with Minors in Math and Entrepreneurship from Baylor University in 2014. He began employment with Unit as an Engineering Intern in the Summers of 2012 and 2013 and joined the company full time as a Production Engineer in 2014. He worked as a production engineer over various company assets with increasing levels of responsibility through 2019. In 2019 he transitioned into a Reservoir Engineering role, where he has been involved in reserve evaluation, project and asset development planning, and acquisition and divestiture assessment.

As part of their continuing education Mr. Smith and Mr. Pickens have attended various seminars and forums to enhance their 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 Form 10-K. The wells or locations for which reserve estimates were audited were taken from our reserve and income projections as of December 31, 2022, and comprised approximately 86% 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 Society of Petroleum Engineers (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, 2022, 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, 2022 and 2021, 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 Item 8 of 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. One third-party customer accounted for 10% of our oil and natural gas revenues during the year ended December 31, 2022 and no other company accounted for over 10% of our oil and natural gas revenues besides affiliate transactions with our Superior investment. Superior purchased $67.1 million of our natural gas and NGLs production and provided gathering and transportation services of $2.7 million. All intercompany transactions and accounts between Unit and Superior during the two months prior to the March 1, 2022 deconsolidation have been eliminated. Affiliate transactions and accounts between Unit and Superior subsequent to March 1, 2022 are not eliminated.

CONTRACT DRILLING

General. Our contract drilling business is conducted through Unit Drilling Company. We drill onshore oil and natural gas wells for a wide range of other oil and natural gas companies as well as for our own account. Our drilling operations are primarily located in Oklahoma, Texas, New Mexico, Wyoming, and North Dakota.

The following table presents information about our contract drilling segment assets as of December 31, 2022 and drilling activity for the year then ended:

	Year Ended December 31,	
	2022	2021
Number of drilling rigs available for use at end of period	18	21
Average number of drilling rigs utilized	16.4	10.9
Utilization rate [(1)]	78 %	36 %
Average revenue per day [(2)]	$ 24,619	$ 19,097
Total footage drilled (in thousands of feet)	5,679	4,487
Number of wells drilled	306	251

1. Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs available for use during the year. See *Drilling Rig Fleet* below for discussion on the 2022 reduction in drilling rigs available for use.

2. Represents the total revenues from our contract drilling segment divided by the total days our drilling rigs were used during the year.

Description and Location of Our Drilling Rigs. An on-shore drilling rig is composed of major equipment components like engines, drawworks or hoists, derrick or mast, substructure, mud pumps, blowout preventers, top drives, and drill pipe. Because of the normal wear and tear from operating 24 hours a day, several of the major components, like engines, mud pumps, top drives, and drill pipe, must be replaced or overhauled periodically. Other major components, like the substructure, mast, and drawworks, can be used for extended periods with proper inspections and maintenance. We also own additional equipment used in operating our drilling rigs, including iron roughnecks, automated catwalks, skidding systems, large air compressors, trucks, and other support equipment. The majority of the wells we drill today are horizontal wells. Depending on our customers' well programs, we routinely drill horizontal wells ranging from 15,000 to over 25,000 feet in length..

The following table presents the contractual status and capabilities of our drilling rigs as of December 31, 2022:

	Contracted Rigs	Non-Contracted	Total Rigs	Average Rated Drilling Depth (ft)
BOSS rigs	14	—	14	20,000
SCR rigs	3	1	4	20,000
Total rigs	17	1	18	20,000

Fluctuating commodity prices directly affect the number of drilling rigs we can put to work, both positively and negatively. Generally, sustained higher commodity prices lead to greater demand for drilling rigs, while demand and rates tends to fall as commodity prices decline for any extended period. Drilling rig utilization increased during 2022 as commodity prices increased. The number of drilling rigs we can work also depends on several conditions besides demand, including the availability of qualified labor as well as the availability of needed drilling supplies and equipment.

The following table presents the average number of our drilling rigs working by quarter during the years indicated:

	2022	2021
First quarter	15.5	9.4
Second quarter	16.3	10.0
Third quarter	17.0	11.0
Fourth quarter	17.0	13.2

Drilling Rig Fleet. Total rigs available for use was reduced from 21 to 18 as of December 31, 2022 reflecting the current market outlook for utilization of our SCR rigs.

Dispositions. Proceeds for the sale of non-core contract drilling assets totaled $12.8 million and $12.7 million during the twelve months ended December 31, 2022 and 2021, respectively. These proceeds resulted in net gains of $8.4 million and $10.1 million during the twelve months ended December 31, 2022 and 2021, respectively.

Drilling Contracts. Our third-party drilling contracts are generally obtained through competitive bidding on a well-by-well basis. Contract terms and payment rates vary depending on the type of contract used, the duration of the work, the equipment and services supplied, and other matters. We pay certain operating expenses, including the wages of our drilling rig personnel, maintenance expenses, and incidental drilling rig supplies and equipment. The contracts are usually subject to early termination by the customer subject to the payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property, and for acts of pollution. The specific terms of these indemnifications are negotiated on a contract-by-contract basis.

All of our drilling contracts during 2022 and 2021 were daywork contracts. Under a daywork contract, we provide the drilling rig with the required personnel and the operator supervises the drilling of the well. Our daywork compensation is based on a negotiated rate to be paid for each day the drilling rig is used.

Most of our contracts are term contracts, with the rest being either well-to-well or pad-to-pad contracts. Term contracts can range from months to multiple years and the rates can either be fixed throughout the term or allow for periodic adjustments.

Customers. Five customers accounted for 71% of our contract drilling revenues during the year ended December 31, 2022. No other third-party customer accounted for 10% or more of our contract drilling revenues.

Our contract drilling segment may also provide drilling services for our oil and natural gas segment. Depending on the timing of the drilling services performed on our properties, those services may be deemed, for financial reporting purposes, to be associated with acquiring an ownership interest in the property. Revenues and expenses for these services are eliminated in our statement of operations, with any profit recognized reducing our investment in our oil and natural gas properties. We eliminated $0.4 million of contract drilling revenue and $0.2 million of contract drilling operating costs during the year ended December 31, 2022, resulting in a net reduction of $0.1 million to our investment in oil and natural gas properties.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries, of which we own a 50% interest. Superior's operations consist of buying, selling, gathering, processing, and treating natural gas. Superior operates three natural gas treatment plants, 12 processing plants, 18 active gathering systems, and approximately 3,802 miles of pipeline. Superior and its subsidiaries operate in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

Superior is governed and managed under the Amended and Restated Limited Liability Company Agreement (Agreement) and a Management Services Agreement (MSA). The MSA is between our wholly-owned subsidiary, SPC Midstream Operating, L.L.C. (the Operator) and Superior. As the Operator, we provide services, such as operations and maintenance support, accounting, legal, and human resources to Superior for a monthly service fee of $0.3 million.

The Agreement specifies how future distributions are to be allocated among the Members. Distributions from Available Cash (as defined in the Agreement) were generally split evenly between the Members prior to December 31, 2021, when the three-year period for Unit's commitment to spend $150.0 million (Drilling Commitment Amount) to drill wells in the Granite Wash/Buffalo Wallow area ended. The total amount spent by Unit towards the Drilling Commitment Amount was $24.6 million. Accordingly, SP Investor will receive 100% of Available Cash distributions related to periods subsequent to December 31, 2021 until the $72.7 million Drilling Commitment Adjustment Amount (as defined in the Agreement) is satisfied.

The following table presents the distributions paid by Superior to each of the members during the years ended December 31, 2022 and 2021:

Date	Recipient	Amount
2022		
October 31, 2022	SP Investor	$16.2 million
July 29, 2022	SP Investor	$13.9 million
April 29, 2022	SP Investor	$10.5 million
January 31, 2022	Unit Corporation	$9.5 million
January 31, 2022	SP Investor	$9.5 million
2021		
October 29, 2021	Unit Corporation	$7.0 million
October 29, 2021	SP Investor	$7.0 million
July 30, 2021	Unit Corporation	$3.8 million
July 30, 2021	SP Investor	$3.8 million
April 30, 2021	Unit Corporation	$12.3 million
April 30, 2021	SP Investor	$12.3 million

Superior also paid distributions to SP Investor of $11.1 million in January 2023 which reduced the remaining Drilling Commitment Adjustment Amount to $20.9 million.

After April 1, 2023, either Member may initiate a sale process of Superior to a third-party or a liquidation of Superior's assets (Sale Event). In a Sale Event, the Agreement generally requires cumulative distributions to SP Investor in excess of its original $300.0 million investment sufficient to provide SP Investor a 7% internal rate of return on its capital contributions to Superior before any liquidation distribution is made to Unit. As of December 31, 2022, liquidation distributions paid first to SP Investor of $335.2 million would be required for SP Investor to reach its 7% Liquidation IRR Hurdle at which point Unit would then be entitled to receive up to $335.2 million of the remaining liquidation distributions to satisfy Unit's 7% Liquidation IRR Hurdle with any remaining liquidation distributions paid as outlined within the Agreement.

On February 21, 2023, we entered into a letter agreement (the "Letter Agreement") with SP Investor under which the Company has agreed to sell all of its 50% ownership interest in Superior for $20.0 million. The Letter Agreement provides that SP Investor will pay Unit $12.0 million at closing and $8.0 million in deferred proceeds to be paid no later than 12 months from closing, subject to Unit's satisfaction of certain ongoing covenant obligations and other customary conditions.

COMPETITION

All our businesses are highly competitive and price sensitive. Competition in the contract drilling business traditionally involves factors such as demand, price, efficiency, the condition of equipment, availability of labor and equipment, reputation, and customer relations.

Our oil and natural gas operations likewise encounter strong competition from other oil and natural gas companies. 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 drilling success and the 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.

Our mid-stream investment competes with purchasers and gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, and independent gatherers for the right to purchase natural gas and NGLs, build gathering and processing systems, and deliver the natural gas and NGLs once the gathering and processing systems are established. The principal elements of competition include the rates, terms, and availability of services, reputation, and the flexibility and reliability of service.

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, 2022, we had 653 employees, none of whom are members of a union or labor organization. Our workforce includes 512 employees in our contract drilling segment, 102 employees in our oil and natural gas segment, and 39 in our general corporate group. 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 services from the oil and natural gas exploration and development industry, and 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 counter parties. 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.

Although in the past Congress has been very active in natural gas regulation as discussed above, the more recent trend has been for deregulation and the promotion of competition in the natural gas industry. In addition to "first sales" deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There continually are legislative proposals pending in the Federal and state legislatures which, if enacted, would significantly affect the petroleum industry. It is impossible to predict what proposals might be enacted by Congress or the various state legislatures and what effect these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

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 gaswastes, 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 (Corps). The scope of the Clean Water Act's jurisdiction has been the subject of significant uncertainty and litigation in recent years. For example, under the Obama Administration, the EPA and the U.S. Army Corp of Engineers proposed a new expansive definition of the "waters of the United States," known as the "Clean Water Rule." However, during the Trump Administration, the EPA and the Corps replaced the Clean Water Rule with the Navigable Waters Protection Rule (NWPR), which narrows the definition of "waters of the United States" to four categories of jurisdictional waters and includes twelve categories of exclusions, including groundwater; however, these rulemakings are currently subject to litigation and it is possible that the Biden Administration could propose a broader definition for these regulated waters. Both the Clean Water Rule and the NWPR are subject to ongoing litigation, with the Clean Water Rule in effect in certain states and the NWPR in effect in others. In addition, in an April 2020 decision defining the scope of the Clean Water Act that was handed down just days after the NWPR was published, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the Clean Water Act and require a permit. The Court rejected the EPA's and Corps' assertion that groundwater should be totally excluded from the Clean Water Act. The Court's decision is expected to bolster challenges to the NWPR." As a result of these developments, the scope of jurisdiction under the Clean Water Act is uncertain at this time.

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. All three of our business segments 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, lesser prairie chicken, and greater sage grouse. In addition, the Supreme Court held in 2018 that only the actual habitat of an endangered species can be designated critical habitat, meaning that an uninhabited area that otherwise meets the definition of critical habitat should not be so designated. Following this decision, the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service NMFS) issued joint regulations in December 2020 defining critical habitat to mean an area that currently or periodically contains the resources and conditions necessary to support a species listed under the ESA. The Department of Interior (DOI) also finalized rules in January 2021 under the Migratory Bird Treaty Act, which imposes similar restrictions and penalties as those found under the ESA, that limit the imposition of criminal sanctions in instances where only an incidental take of protected birds occurs. The Biden Administration has stated that it plans to review the FWS, NMFS, and DOI regulations and has paused implementation of the DOI rules. The presence of protected species in areas where we provide contract drilling or mid-stream services 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.

In September 2020, the Trump Administration finalized regulations that removed the transmission and storage segments from the oil and natural gas source category and rescinded the methane specific requirements across all sources. These changes are currently subject to litigation, and Congress is considering repealing the September 2020 revisions pursuant to the Congressional Review Act. In addition, in January 2021, President Biden signed an executive order calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emissions standards for new, modified, and existing oil and gas facilities. As a result, more stringent regulation of methane emissions from the oil and natural gas industry is expected.

The EPA recently proposed amendments designed to update, strengthen, and expand federal regulation of methane and VOCs emitted from new, modified, and reconstructed oil and gas facilities. When finalized, the proposal would revise the standards for sources constructed or modified after August 2011 and September 2015, respectively, create new standards for sources constructed or modified after November 2021, and create a new subpart which would impose on each state the obligation to adopt conforming emissions standards for existing sources.

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. The IRA also includes a charge on methane emissions which is the first ever federal fee on emissions through a methane emissions charge. Facilities required to report their greenhouse gas (GHG) emissions to the EPA will be assessed a fee of $900 per metric ton of methane in 2024, increasing to $1,500 per metric ton for 2026 and each year thereafter.

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."

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by the recently elected administration. These have included promises to limit emissions and curtail the production of oil and gas on federal lands, such as through the cessation of leasing public land for hydrocarbon development. For example, in January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across governmental agencies and economic sectors. Additionally, President Biden has signed executive orders recommitting the United States to the Paris Agreement, which requires member nations to submit non-binding, individually determined GHG emission reduction goals every five years after 2020. The impacts of these orders and the terms of any legislation or regulation to implement the United States' commitment under the Paris Agreement remain unclear at this time. There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

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. Our oil and natural gas segment routinely apply hydraulic fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. 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. For example, the EPA 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. Most recently, on March 23, 2021 the Fracturing Responsibility and Awareness of Chemicals Act was reintroduced in Congress, which includes resolutions that would authorize the EPA to regulate unconventional drilling activities, including requiring the disclosure of chemicals used, and end various exemptions for hydraulic fracturing in federal laws such as RCRA, the Safe Drinking Water Act, and the federal Clean Air Act. 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.

Item 1A. Risk Factors

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. Prices also tend to influence third parties use of our services. 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, such as the current conflict occurring between Russia and Ukraine;
- 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, such as COVID-19; and
- worldwide economic conditions.

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, 2022, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $0.2 million per month ($2.4 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 ($1.3 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 $0.2 million per month ($2.2 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. To date, we have derivatives covering part, but not all of our production, which provides price protection only against declines in market prices on the production covered by those derivatives, but not otherwise. Should market prices for the production we have derivatives on exceed the prices due under our derivative contracts, our derivative contracts expose us to the risk of financial loss and limit the benefit to us of those increases in market prices. Volumes not covered by derivative contracts are subject to market prices. The Management's Discussion and Analysis of Financial Condition and Results of Operations section of this report in Item 7 has a more thorough discussion of our derivative arrangements.

If one or more of our counterparties are unable or unwilling to pay us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and operating results.

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, the carrying value of our drilling rigs, or our natural gas gathering and processing systems.

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 drilling equipment, transportation equipment, gas gathering and processing systems, and 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.

What's more, the 10% discount factor, required by the SEC for calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate 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 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 a combination of internally generated cash flow and borrowings under our credit agreement. We may have some indebtedness. As of December 31, 2022, we had no outstanding borrowings under our credit agreement.

Depending on our debt, 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 our 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. If that were to happen, we would not have sufficient funds available (and probably could not obtain the financing required) to meet our obligations. See "Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict" below.

Our existing debt and our future debt are based mainly on the costs of the projects we undertake and our cash flow. Generally, our expected operating costs are those resulting from the drilling of oil and natural gas wells, acquiring producing properties, the costs associated with the maintenance, upgrade, or expansion of our drilling rig fleet, and the operations of our natural gas buying, selling, gathering, processing, and treating systems. To some extent, these costs, mainly the first two, are discretionary, and we maintain some control on the timing or the need to incur them. Sometimes, unforeseen circumstances may arise, like an unexpected chance to make a large acquisition or the need to replace a costly drilling rig component due to an unexpected loss, which could force us to incur more debt above what we had expected or forecasted. Likewise, if our cash flow should prove insufficient to cover our cash requirements, we would need to increase our debt either through bank borrowings or otherwise.

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, 2022, we had no outstanding borrowings under our credit agreement. Our financing agreements permit us to incur more indebtedness and other obligations. We may also seek amendments or waivers from our existing lenders if we need to incur indebtedness above amounts permitted by our financing agreements.

Our credit facilities contain 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;
- pay dividends or make other distributions;
- 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 facilities also require 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 lenders under our credit facilities may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due. The lenders 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 lenders 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.

Under the Exit credit agreement, the borrowing base is determined semi-annually at the lenders' discretion and is based largely on the prices for oil, NGLs, and natural gas.

Significant declines in oil, NGLs, and natural gas prices may cause a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base, and therefore the borrowings permitted to be outstanding under the Exit credit agreement. If outstanding borrowings are over the borrowing base, we must (a) repay the amount over the borrowing base, (b) dedicate additional properties to the borrowing base, or (c) begin monthly principal payments.

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 or authorize share repurchases at the current rate or at all. 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, like the recent global outbreak of COVID-19, have materially hurt and may further materially hurt our business.

We face risks related to epidemics, pandemics, outbreaks, or other public health events outside our control and could disrupt our operations and hurt their financial condition. The outbreak of the COVID-19 virus has spread across the globe and affected financial markets and worldwide economic activity. It may continue to negatively impact our operations or our workforce's health by rendering employees or contractors unable to work or unable to access our facilities for an indefinite period. The effects of COVID-19 and concerns about its global spread have, during certain periods, weakened the domestic and international demand for crude oil and natural gas, hurting crude oil prices and causing significant price volatility. As the duration and full impact from COVID-19 is difficult to predict, how much it may hurt our operating results, or the duration of any potential business disruption is unknown. Any potential impact will depend on future developments, and new information that may emerge about the severity and duration of COVID-19 and the actions taken by authorities to contain it or treat its impact are beyond our control. These potential impacts, while unknown, could hurt our operating results.

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

The drilling industry in which we operate is generally very competitive. Most drilling contracts are awarded based on competitive bids, which may cause intense price competition. Some of our competitors in the contract drilling industry have greater financial and human resources than we do. These resources may enable them to withstand periods of low drilling rig use better, compete more effectively based on price and technology, build new drilling rigs, or acquire existing drilling rigs, and provide drilling rigs more quickly than we do in periods of high drilling rig use.

The oil and natural gas industry is also 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.

The mid-stream industry is also highly competitive. Our mid-stream investment competes in gathering, processing, transporting, and treating natural gas with other mid-stream companies. Superior is continually competing with larger mid-stream companies for acquisitions and construction projects. Many of Superior's competitors have greater financial resources, human resources, and geographic presence than it does.

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

Our three segments' success and the success of our other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, drilling rig hands, 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 contract drilling operations are subject to many hazards, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment, and damage or loss from inclement weather. Our exploration and production and mid-stream operations are subject to these and similar risks. These events could cause personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage, and damage to others' property. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer. We seek to obtain contractual indemnification from our drilling customers for some of these risks. If we cannot transfer these risks to drilling customers by contract or indemnification agreements (or if we assume obligations of indemnity or assume liability for certain risks under our drilling contracts), we seek protection from some of these risks through insurance. Still, some risks are not covered by insurance. We cannot assure you that the insurance we have or the indemnification agreements we have will adequately protect us against liability from the consequences of the hazards described above. An event not fully insured or indemnified against, or a customer's failure to meet its indemnification obligations, could cause substantial losses. We cannot assure you that insurance will be available to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

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. Although we may disclose our overall drilling success rate, those rates may decline. Although we may discuss drilling prospects we have identified or budgeted for, we may ultimately not lease or drill these prospects within the expected period, or at all. Lack of drilling success will hurt our future results of operations and financial condition. We do not operate many 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 oil and natural gas segment's 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. The SEC's reserve reporting rules require 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, 2022, we had no proved undeveloped drilling locations.

Our mid-stream investment's operations involve many risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial, and Superior's ability to recoup these costs is uncertain. Superior's operations may be curtailed, delayed, or canceled because of many things beyond its control, including:

- unexpected changes in the deliverability of natural gas reserves from the wells connected to the gathering systems;
- availability of competing pipelines in the area;
- the capacity of pipeline systems;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements;
- delays in developing other producing properties within the gathering system's area of operation; and
- demand for natural gas and its constituents.

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, 2022, one customer accounted for 10% of our oil and natural gas revenue, five customers accounted for 71% of our contract drilling revenues, and three customers accounted for 65% of our mid-stream revenues. No other third-party customer accounted for 10% or more of any of our segment revenues. Any customer may choose not to use our services or 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 could not find replacements.

Superior depends on certain natural gas producers and pipeline operators for a significant portion of its supply of natural gas and NGLs. Losing any of these producers could cause a decline in its volumes and revenues.

Superior relies on certain natural gas producers for a significant portion of our natural gas and NGLs supply. While some of these producers are subject to long-term contracts, Superior may not negotiate extensions or replacements of these contracts on favorable terms, if at all. Losing all or even a portion of the natural gas volumes supplied by these producers, because of competition or otherwise, could have a material adverse effect on our mid-stream segment unless Superior acquired comparable volumes from other sources.

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.

Demand for our contract drilling and Superior's mid-stream services depends on the levels of spending by the oil and gas industry. A substantial or an extended decline in oil and gas prices could cause lower spending by the oil and gas industry, which could have a material adverse effect on our financial condition, results of operations, and cash flows.

Demand for our contract drilling and Superior's mid-stream services depends on the oil and gas industry's level of expenditures for the exploration, development, and production of oil and natural gas reserves. These expenditures generally depend on the industry's view of future oil and natural gas prices and are sensitive to the industry's view of future economic growth and the resulting effect on demand for oil and natural gas. Declines and anticipated declines in oil and gas prices could also cause project modifications, delays, or cancellations, general business disruptions, and delays in payment of, or nonpayment of, amounts owed to us. These effects could have a material adverse effect on our financial condition, results of operations, and cash flows.

Climate change legislation or other regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, natural gas and NGL 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. 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."

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by the recently elected administration. These have included promises to limit emissions and curtail the production of oil and gas on federal lands, such as through the cessation of leasing public land for hydrocarbon development. For example, in January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across governmental agencies and economic sectors. Additionally, President Biden has signed executive orders recommitting the United States to the Paris Agreement, which requires member nations to submit non-binding, individually determined GHG emission reduction goals every five years after 2020. The impacts of these orders and the terms of any legislation or regulation to implement the United States' commitment under the Paris Agreement remain unclear at this time. There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

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, including the conflict between Russia and Ukraine, 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, including the conflict between Russia and Ukraine, 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

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 available borrowing capacity under the Exit credit agreement and cash flow generated from operations. If our cash flow from operations decreases, 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 the Exit credit agreement, (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.

We have historically grown through mergers and acquisitions. The contract land drilling industry, the exploration and development industry, and the gas gathering and processing 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. In addition, continued growth 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.

If we are to construct new proprietary BOSS drilling rigs, the process would be subject to risks, including delays and cost overruns, and rigs that may not meet our expectations.

We have designed and built several proprietary 1,500 horsepower AC electric drilling rigs called BOSS drilling rigs. This new design should position us to meet the demands of our customers better. Constructing any future new BOSS drilling rigs is subject to the risks of delays or cost overruns in any large construction project because of many possible factors.

BOSS drilling rig designs may be subject to intellectual property rights claims.

While we hold certain patents on our BOSS drilling rig design, it is still possible that third parties may claim that our BOSS drilling rig design infringes on their intellectual property rights. In that event, we may resolve these claims by signing royalty and licensing agreements, redesigning the drilling rig, or paying damages. These outcomes may cause operating margins to decline. In addition to money damages, plaintiffs may seek injunctive relief in some jurisdictions that may limit or prevent marketing and use of our drilling rigs if they are determined to be an infringement upon a third party's intellectual property rights.

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.

Emissions regulations or legislation, including the Inflation Reduction Act of 2022, could accelerate the transition away from fossil fuels and increase the costs of our operations.

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. These incentives could accelerate the transition away from the use of fossil fuels, which could decrease demand for oil and natural gas having an adverse impact on our business.

The IRA also includes a charge on methane emissions, which is the first ever federal fee on emissions through a methane emissions charge. Facilities required to report their greenhouse gas (GHG) emissions to the EPA, which includes our facilities, will be assessed a fee of $900 per metric ton of methane in 2024, increasing to $1,500 per metric ton for 2026 and each year thereafter. These new fees and the related compliance and monitoring costs could increase the costs of our operations.

Superior could be subject to increased compliance costs related to the regulation of its pipelines.

Superior's pipelines are also subject to regulation by the Department of Transportation (DOT) under the Natural Gas Pipeline Safety Act of 1968, as amended, Hazardous Liquid Pipeline Safety Act of 1979, as amended, the Pipeline Safety Act of 1992, as reauthorized and amended, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act). The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) implements these statutes. Recently, PHMSA has taken several steps to expand its jurisdiction over crude oil and natural gas pipelines, including gathering lines.

PHMSA issued three separate final rulemakings in 2019 that significantly expand the regulation of natural gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, and maximum allowable operating pressure limits, among others. PHMSA has also finalized rules for hazardous liquids pipelines that expand existing pipeline integrity management requirements. In addition, the final rule extends annual and accident reporting requirements to gravity lines and all gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events, natural disasters, such as hurricanes, landslides, floods, earthquakes, or other similar events that are likely to interfere with our production, increase our cost and damage infrastructure.

On August 3, 2020, the United States Senate reauthorized the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act to reauthorize pipeline safety programs through fiscal year 2023. The PIPES Act contains provisions for methane leak detection, monitoring, and repair, the maintenance of emergency response plans, and other pipeline safety regulations. Therefore, additional future regulatory action expanding PHMSA’s jurisdiction and imposing stricter integrity management requirements is possible. The adoption of laws or regulations that apply more comprehensive or stringent safety standards could require Superior to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require Superior to incur increased operating costs that could be significant. In addition, should Superior fail to comply with PHMSA or comparable state regulations, Superior could be subject to substantial fines and penalties. Effective January 11, 2021, the maximum civil penalties PHMSA can impose are $222,504 per violation per day, with a maximum of $2,225,034 for a related series of violations.

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 segment routinely applies 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.

Uncertainty about increased seismic activity in Oklahoma could have adverse effect on our business and results of operations.

We conduct oil and natural gas exploration, development, and drilling activities in Oklahoma and nearby. In recent years, Oklahoma, Texas, and Kansas have experienced an upturn in earthquakes and other seismic activity. Some parties believe there is a correlation between certain oil and gas activities and earthquakes' increased occurrence. The extent of this correlation is the subject of studies by both state and federal agencies, the results of which remain unclear. We cannot say what impact this seismic activity may have on us or our industry.

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 segment 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. All three of our business segments 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, lesser prairie chicken, and greater sage grouse.

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.

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

Our internal control 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 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 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.

While our New Common Stock is being quoted on the OTCQX® Best Market, the OTCQX® Best Market 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 stockholders 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 stockholders 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 stockholders 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 stockholders 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:

- 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.
- The Board of Directors is divided into two classes, Group I and Group II. The Group I directors initially served until the Company's 2023 annual meeting of stockholders, and the Group II directors will initially serve until the Company's 2022 annual meeting of stockholders. 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.
- Courts in Delaware are the exclusive forum for derivative actions and certain other actions and claims.
- To ensure the preservation of certain tax attributes to benefit the Company and its stockholders, the charter contains certain restrictions on transfer of the Company's equity securities by persons with a percentage stock ownership of 4.75% or more.
- Special meetings of the stockholders may only be called by the Board of Directors or by the secretary of the Company at the request of stockholders owning at least 25% of the voting stock.
- 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.
- Vacancies on our Board of Directors and newly created directorships will be filled solely by the affirmative vote of a majority of directors then in office, even if less than a quorum, or by a sole remaining director.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information called for by this item was consolidated with and disclosed in connection with Item 1 above.

Item 3. Legal Proceedings

For more information regarding legal proceedings, see Note 20 - Commitments And Contingencies of our Notes to Consolidated Financial Statements in Item 8 of this report.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market and Stockholder Information

Our common stock is traded on the OTCQX® Best Market under the symbol "UNTC". See "Risk Factors — Our New Common Stock may have a limited market and lack liquidity" under Item 1A of this report. Most of our stockholders maintain their shares in "street name" accounts and are not, individually, stockholders of record. As of March 17, 2023, there were nine holders of record of our common stock.

Common Stock Dividends

On January 5, 2023, the Company issued a press release announcing the declaration of a special cash dividend of $10.00 per share and has approved a quarterly cash dividend policy beginning in the Company's second quarter. The special dividend was paid on January 31, 2023, to stockholders of record as of the close of business on January 20, 2023. The initial quarterly dividend will be $2.50 per share to be paid on a date in the Company's second quarter that is yet to be determined. Subsequent quarterly dividends will be issued on a variable rate per share basis as determined by the Company. The special and quarterly cash dividends will be funded by cash on the Company's balance sheet.

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. Under certain circumstances, none of which applied as of December 31, 2022, our bank credit agreements may restrict the payment of cash dividends on our common stock. For further information regarding how our bank credit agreements may impact our ability to pay dividends, see "Credit Agreements" under Item 7 of this report.

Share Repurchases

The table below presents the common stock repurchase activity during the periods indicated:

	Shares	Purchase Price	Price per Share
	(in thousands, except for per share amounts)		
2022			
Repurchase Program (1)	522,429	$ 27,421	$ 52.49
Total Repurchases	522,429	$ 27,421	$ 52.49
2021			
Repurchase Program (1)	1,271,963	$ 41,430	$ 32.57
Lender Repurchases (2)	600,000	$ 9,000	$ 15.00
Other Repurchases (3)	78,000	$ 1,487	$ 19.07
Total Repurchases	1,949,963	$ 51,917	$ 26.62

1) In June 2021, the Company's Board of Directors (the Board) authorized repurchasing up to $25.0 million of the Company's outstanding common stock. The Board subsequently authorized increases to the authorized repurchases up to $50.0 million in October 2021 and then up to $100.0 million in June 2022. The repurchases are made through open market purchases, privately negotiated transactions, or other available means. The Company has no obligation to repurchase any shares under the repurchase program and may suspend or discontinue it at any time without prior notice. As of December 31, 2022, we had repurchased a total of 1,794,392 shares under the repurchase program at an average share price of $38.37 for an aggregate purchase price of $68.9 million.

2) In June 2021, we repurchased our common stock from the Lenders (as defined in Note 9 - Long-Term Debt and Other Long-Term Liabilities) which received these shares as an exit fee during our reorganization.

3) During the year ended December 31, 2021, we repurchased shares in a privately negotiated transaction which was not part of the repurchase program.

The cumulative number of shares repurchased as of December 31, 2022 totaled 2,472,392.

The table below represents all share repurchases for the three months ended December 31, 2022:

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced program	Approximate dollar value of shares that may yet be purchased under the program
				(in thousands)
October 1, 2022 through October 31, 2022	—	$ —	—	$ 31,149
November 1, 2022 through November 30, 2022	—	$ —	—	$ 31,149
December 1, 2022 through December 31, 2022	—	$ —	—	$ 31,149

Item 6. [Reserved]

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

Please read this discussion of our financial condition and results of operations with the consolidated financial statements and related notes in Item 8 of this report.

Introduction

We operate, manage, and analyze our results of operations through our three principal business segments:

- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Contract Drilling – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Mid-Stream – carried out by Superior and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account. We hold a 50% investment in Superior.

Oil and Natural Gas

In our oil and natural gas segment, we are optimizing production and converting non-producing reserves to producing with selective drilling activities. We also anticipate continuing to hedge a portion of our future production depending on future market pricing among other factors.

Contract Drilling

In our contract drilling segment, we are focused on maintaining utilization of our drilling rigs in a safe and efficient manner. All 14 of our BOSS drilling rigs are currently operating. Most of our drilling rigs are contracted for periods of 12 months or less. During the fourth quarter of 2022, contracts on five BOSS drilling rigs repriced at higher dayrates. We expect that contracts on 11 BOSS drilling rigs will be up for change or renegotiation between December 31, 2022 and June 30, 2023. Effective December 31, 2022, we reduced the number of total rigs available for use from 21 to 18, reflecting the current market outlook for utilization of SCR rigs.

Mid-Stream

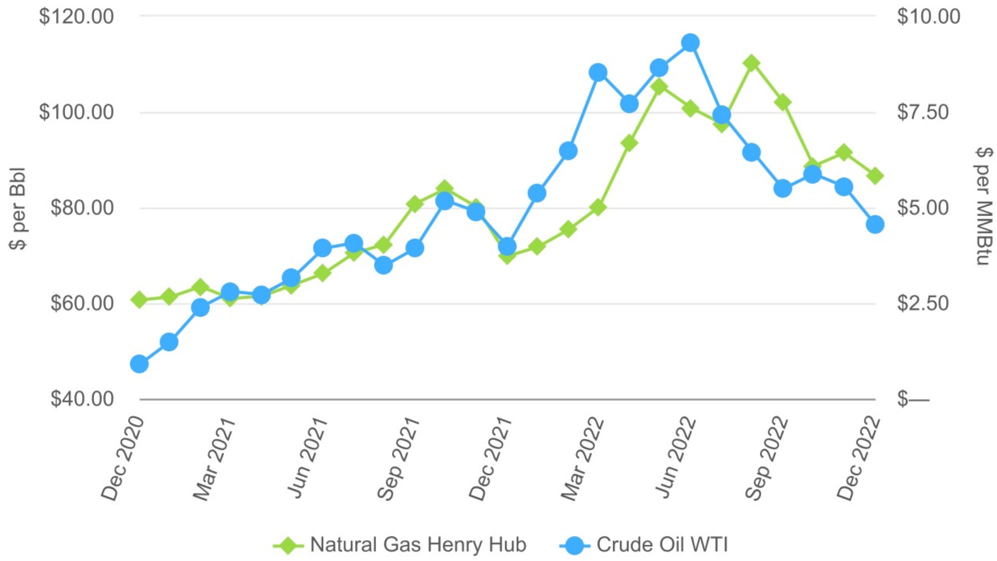
In our mid-stream segment, Superior is focused on continuing to generate predictable free cash flows with limited exposure to commodity prices in addition to seeking business development opportunities in its core areas utilizing the Superior credit agreement (which Unit is not a party to and does not guarantee) or other financing sources that are available to it. We hold a 50% investment in Superior, and subsequent to the deconsolidation of Superior as of March 1, 2022, we report our ownership interest as an equity method investment. The following discussion of financial condition and results of operations pertaining to our mid-stream segment during the year ended December 31, 2022 relates to the two months of consolidated results prior to deconsolidation as of March 1, 2022.

Recent Developments

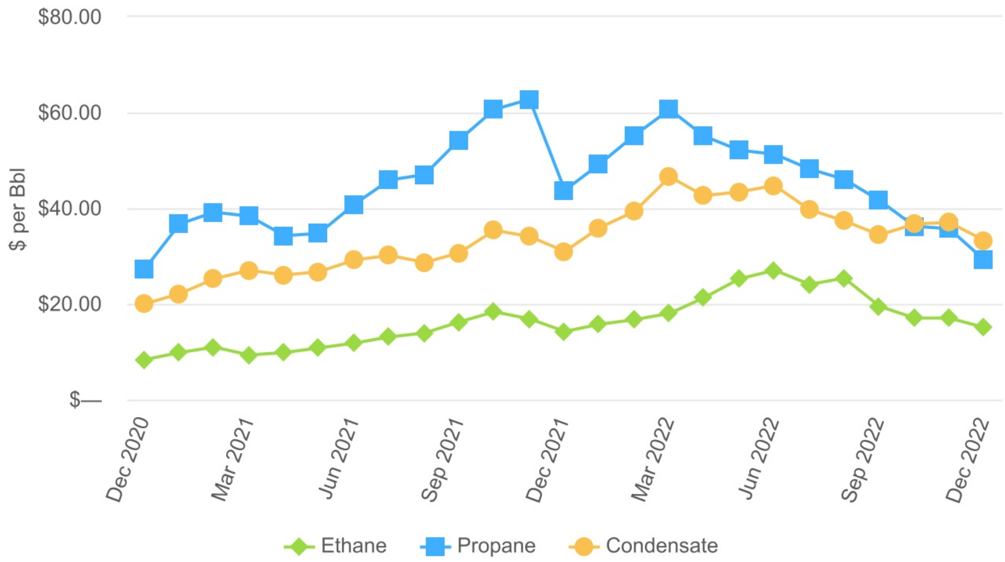
Commodity Price Environment

The prices we receive for our oil and natural gas production, the demand for oil, natural gas, and NGLs, and the demand for our drilling rigs, which influences the amounts we can charge for those drilling rigs, 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.

Oil, natural gas, and NGL pricing generally improved during 2021 and much of 2022 as demand recovered from the COVID-19 pandemic while oil supply was negatively impacted by the conflict between Russia and Ukraine as well as restrained production growth from OPEC+, among other factors. Prices generally declined later in 2022 due to growing economic uncertainty and recession concerns and improved supply, among other factors. Commodity prices have been volatile in recent years and the outlook for future oil and gas prices remains uncertain and subject to many factors. The following chart reflects the significant 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

On January 5, 2023, the Company announced the declaration of a special cash dividend of $10.00 per share and has approved a quarterly cash dividend policy beginning in the Company's second quarter. The special dividend was paid on January 31, 2023, to stockholders of record as of the close of business on January 20, 2023. The initial quarterly dividend will be $2.50 per share to be paid on a date in the Company's second quarter that is yet to be determined. Subsequent quarterly dividends will be issued on a variable rate per share basis as determined by the Company. The special and quarterly cash dividends will be funded by cash on the Company's balance sheet.

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.

Stock Repurchase Activity

The table below presents the common stock repurchase activity during the periods indicated:

	Shares	Purchase Price	Price per Share
	(in thousands, except for per share amounts)		
2022			
Repurchase Program	522,429	$ 27,421	$ 52.49
Total Repurchases	522,429	$ 27,421	$ 52.49
2021			
Repurchase Program	1,271,963	$ 41,430	$ 32.57
Lender Repurchases	600,000	$ 9,000	$ 15.00
Other Repurchases	78,000	$ 1,487	$ 19.07
Total Repurchases	1,949,963	$ 51,917	$ 26.62

As of December 31, 2022, the cumulative number of shares repurchased totaled 2,472,392 and $31.1 million remained available under our repurchase program.

Warrants

Each holder of Unit common stock outstanding (Old Common Stock) before the September 3, 2020 emergence from bankruptcy (Emergence Date) that did not opt out of the release under the Chapter 11 plan (as amended, supplemented and modified from time to time, the "Plan") of reorganization filed with the bankruptcy court on June 9, 2020 is 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, 2022, the Company had authorized 1,822,231 warrants and none had been exercised.

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".

Superior MSA and LLC amendments

Effective March 1, 2022, the employees of the Operator were transferred to Superior and the MSA was amended and restated to remove the operating services the Operator was providing to Superior. There was no change to the monthly service fee for shared services. We no longer consolidate the financial position, operating results, and cash flows of Superior as of, and subsequent to, March 1, 2022. We recognized a $13.1 million loss on deconsolidation during the twelve months ended December 31, 2022 as the difference between the $1.7 million estimated fair value of our retained equity method investment in Superior as of March 1, 2022 and Superior's net equity attributable to Unit's ownership interest prior to deconsolidation. We subsequently account for our investment in Superior as an equity method investment using the hypothetical liquidation book value (HLBV) method which is a balance sheet approach that calculates the change in the hypothetical amount Unit and SP Investor would be entitled to receive if Superior were liquidated at book value at the end of each period, adjusted for any contributions made and distributions received during the period.

On February 21, 2023, we entered into a letter agreement (the "Letter Agreement") with SP Investor under which the Company has agreed to sell all of its 50% ownership interest in Superior for $20.0 million. The Letter Agreement provides that SP Investor will pay Unit $12.0 million at closing and $8.0 million in deferred proceeds to be paid no later than 12 months from closing, subject to Unit's satisfaction of certain ongoing covenant obligations and other customary conditions.

Officer Departure and Appointments

On February 23, 2023, Philip B. Smith notified the Company’s Board of Directors of his decision to step down as President and Chief Executive Officer of the Company effective March 31, 2023. His decision to step down was due to his desire to spend more time working on his nonprofit projects and other endeavors. Mr. Smith will continue to serve as Chairman of the Board of Directors.

In connection with Mr. Smith stepping down as President and CEO, the Board of Directors has approved (i) a pro-rated vesting of his outstanding time-based equity awards scheduled to vest on the next applicable vesting date based on the number of days worked during the then-current vesting period, and (ii) extending the time that Mr. Smith can exercise his options to the expiration date set forth in his award agreement governing the options.

To fill the vacancy created by Mr. Smith’s resignation, on February 28, 2023, the Board of Directors appointed Phil Frohlich as interim Chief Executive Officer, effective April 1, 2023, until the Board of Directors names a successor. Mr. Frohlich has been a member of the Board of Directors since September 3, 2020. Additional information about Mr. Frohlich is contained in Part III of this Annual Report.

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, 2022 covered reserves that we projected to comprise 86% 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 I, Item 1 of this 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, 2022, our reserves were calculated based on applying 12-month 2022 average unescalated prices of $93.67 per barrel of oil and $6.36 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.

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, periods of relatively low drilling rig utilization, declining revenue per day, declining cash margin per day, 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. Our mid-stream segment has property and equipment at locations leased or under right of way agreements which may require asset removal or site restoration, however, we are not able to reasonably measure the fair value of the obligations as the potential settlement dates are indeterminable.

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;
- the prices we receive for our natural gas, oil, and NGLs production;
- the utilization of our drilling rigs and the dayrates we receive for those drilling rigs; and
- the fees and margins we obtain from our natural gas gathering and processing contracts.

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 during the periods indicated:

	Year Ended December 31, 2022	Year Ended December 31, 2021	Percent Change
	(In thousands except percentages)		
Net cash provided by operating activities	$ 159,421	$ 175,969	(9) %
Net cash provided by investing activities	28,896	36,205	(20) %
Net cash used in financing activities	(38,482)	(160,748)	(76) %
Net increase in cash and cash equivalents	$ 149,835	$ 51,426	

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, third-party utilization of our drilling rigs and Superior's mid-stream services, and the rates charged for those drilling and mid-stream services. 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, 2022 decreased by $16.5 million as compared to the year ended December 31, 2021 primarily due to higher payments on derivative settlements and the absence of operating cash flows from Superior subsequent to the March 1, 2022 deconsolidation, partially offset by higher operating cash flows from our oil and natural gas and contract drilling segments.

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 as well as the maintenance of our existing drilling rig fleet.

Net cash provided by investing activities decreased by $7.3 million during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to the deconsolidation of Superior's cash and cash equivalents and lower proceeds received from the disposition of non-core property and equipment, partially offset by lower capital expenditures. Capital expenditures decreased primarily due to lower spend from Superior due to its March 1, 2022 deconsolidation and the absence of Superior's 2021 gathering and processing system acquisition, partially offset by higher capital spend in our contract drilling and oil and natural gas segments.

Cash Flows from Financing Activities

Net cash used in financing activities decreased by $122.3 million during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to the absence of net payments on credit agreements and finance leases, lower repurchases of common stock, and lower distributions made by Superior to non-controlling interests due to Superior's March 1, 2022 deconsolidation. A portion of future cash flows and cash and cash equivalents may be used for future shareholder return activities, including stock repurchases and cash distributions.

As of December 31, 2022, we had unrestricted cash and cash equivalents totaling $214.0 million and no outstanding borrowings under the Exit credit agreement.

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

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(In thousands)	
Working capital	$ 207,237	$ 5,792
Current portion of long-term debt	$ —	$ —
Long-term debt	$ —	$ 19,200
Shareholders' equity attributable to Unit Corporation	$ 362,626	$ 187,397

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 $207.2 million at December 31, 2022 compared to positive working capital of $5.8 million as of December 31, 2021. The increase in working capital is primarily due to higher cash and cash equivalents, lower accounts payable and accrued liabilities, lower current derivative liabilities, and the absence of the warrant liability, partially offset by lower accounts receivable. The Exit credit agreement may be used for working capital.

Credit Agreements

Exit Credit Agreement. On the Effective Date, under the terms of the Plan, 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 Effective Date (other than Superior Pipeline Company, L.L.C. and its subsidiaries), (iii) the lenders party thereto from time to time (Lenders), and (iv) BOKF, NA dba Bank of Oklahoma as administrative agent and collateral agent (in such capacity, the Administrative Agent). The maturity date of borrowings under this Exit credit agreement is March 1, 2024.

Our Exit credit agreement is primarily used for working capital purposes as it limits the amount that can be borrowed for capital expenditures. These limitations restrict future capital projects using the Exit credit agreement. The Exit credit agreement also requires that proceeds from the disposition of certain assets be used to repay amounts outstanding.

On April 6, 2021, the Company finalized the first amendment to the Exit credit agreement. Under the first amendment, the Company reaffirmed its borrowing base of $140.0 million of the RBL, amended certain financial covenants, and received less restrictive terms as it relates to the disposition of assets and the use of proceeds from those dispositions.

On July 27, 2021, the Company finalized the second amendment to the Exit credit agreement. Under the second amendment, the Company obtained confirmation that the Term Loan had been paid in full prior to the amendment date and received one-time waivers related to the disposition of assets.

On October 19, 2021, the Company finalized the third amendment to the Exit credit agreement. Under the third amendment, the Company requested, and was granted, a reduction in the RBL borrowing base from $140.0 million to $80.0 million in addition to less restrictive terms as it relates to capital expenditures, required hedges, and the use of proceeds from the disposition of certain assets, while also amending certain financial covenants.

On March 30, 2022, the RBL Facility borrowing base of $80.0 million was reaffirmed.

On July 1, 2022, the RBL Facility borrowing base was automatically reduced to $31.3 million as a result of closing the Texas Gulf Coast properties sale discussed in Note 5 - Acquisitions And Divestitures.

On November 1, 2022, the Company finalized the fourth amendment to the Exit credit agreement. Under the fourth amendment, (i) the RBL Facility borrowing base was increased to $35.0 million, (ii) the lenders party to the agreement were revised to only BOKF, NA dba Bank of Oklahoma, and (iii) the Eurodollar Loan borrowing option was amended to a secured overnight financing rate (SOFR) option. Subsequent to the fourth amendment, Revolving Loans are able to be SOFR Loans or ABR Loans (each as defined in the Exit credit agreement). Revolving Loans that are SOFR Loans bear interest at a rate per annum equal to the Adjusted Term SOFR Rate (as defined in the Exit credit agreement) for the applicable interest period plus 525 basis points while Revolving Loans that are ABR Loans bear interest at a rate per annum equal to the Alternate Base Rate plus 425 basis points.

Superior Credit Agreement. On May 10, 2018, Superior signed a five-year, $200.0 million senior secured revolving credit facility with an option to increase the credit amount up to $250.0 million, subject to certain conditions (Superior credit agreement). On April 29, 2022, Superior entered into an Amended and Restated Credit Agreement for a four-year, $135.0 million senior secured revolving credit facility with an option to increase the credit amount up to $200.0 million, subject to certain conditions (Amended Superior credit agreement).

Capital Requirements

Oil and Natural Gas Segment Acquisitions, Capital Expenditures, and Dispositions. Most of our capital expenditures for this segment 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 27 gross wells (1.34 net wells) drilled by other operators during the first twelve months of 2022 compared to 12 gross wells (1.75 net wells) during the first twelve months of 2021.

Oil and natural gas segment capital expenditures, including oil and gas properties on the full cost method, for the first twelve months of 2022 totaled $21.0 million, excluding a $4.3 million increase in the ARO liability, compared to $17.8 million, excluding a $0.5 million increase in the ARO liability, during the first twelve months of 2021.

On July 1, 2022, the Company closed on the sale of certain wells and related leases near the Texas Gulf Coast for cash proceeds of $45.4 million, net of customary closing and post-closing adjustments based on an effective date of April 1, 2022. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On March 8, 2022, the Company closed on the sale of certain non-core wells and related leases located near the Oklahoma Panhandle for cash proceeds of $3.6 million, net of customary closing and post-closing adjustments based on an effective date of December 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On August 16, 2021, the Company closed on the sale of substantially all of our wells and related leases located near Oklahoma City, Oklahoma for cash proceeds of $16.1 million, net of customary closing and post-closing adjustments based on an effective date of August 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On May 6, 2021, the Company closed on the sale of substantially all of our wells and the leases related thereto located in Reno and Stafford Counties, Kansas for cash proceeds of $7.3 million, net of customary closing and post-closing adjustments based on an effective date of February 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

Net proceeds for the sale of other non-core oil and natural gas assets totaled $7.7 million and $5.0 million during the twelve months ended December 31, 2022 and 2021, respectively.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. Near term capital expenditures are expected to primarily be for maintenance capital on operating drilling rigs. We also continue to pursue the disposal or sale of our non-core, idle drilling rig fleet. Contract drilling capital expenditures totaled $11.1 million during the first twelve months of 2022 compared to $2.9 million during the first twelve months of 2021.

Proceeds for the sale of non-core contract drilling assets totaled $12.8 million and $12.7 million during the twelve months ended December 31, 2022 and 2021, respectively. These proceeds resulted in net gains of $8.4 million and $10.1 million during the twelve months ended December 31, 2022 and 2021, respectively. The net gains are presented within gain on disposition of assets in the consolidated statements of operations.

Mid-Stream Capital Expenditures and Acquisitions. Superior incurred $1.2 million and $24.5 million in consolidated capital expenditures during the two months prior to the March 1, 2022 deconsolidation and the year ended December 31, 2021, respectively.

In November 2021, Superior closed on an acquisition for $13.0 million that included a cryogenic processing plant, approximately 1,620 miles of low-pressure gathering pipeline, and related compressor stations located in southern Kansas.

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. As of December 31, 2022, based on our fourth quarter 2022 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	2023	2024 and beyond
Daily oil production	48%	—%
Daily natural gas production	45%	—%

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, 2022 and determined there was no material risk at that time. The fair value of the net liabilities we had with Bank of Oklahoma, our only commodity derivative counterparty, was $23.6 million as of December 31, 2022.

Warrants. Prior to the determination of the initial exercise price, we recognized the fair value of the warrants as a derivative liability on our consolidated balance sheets with changes in the liability reported as loss on change in fair value of warrants in our consolidated statements of operations. On April 7, 2022, the Company delivered notice of the initial $63.74 exercise price resulting in the warrants meeting the definition of an equity instrument. Accordingly, we recognized the change in the fair value of the warrant liability in our unaudited condensed consolidated statements of operations and reclassified the $49.1 million warrant liability to capital in excess of par value on the unaudited condensed consolidated balance sheets as of April 7, 2022. The warrants will continue to be reported as capital in excess of par value and are no longer subject to future fair value adjustments.

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

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Loss on derivatives	$ (63,610)	$ (97,615)
Cash settlements paid on commodity derivatives	(98,775)	(44,591)
Loss on derivatives less cash settlements paid on commodity derivatives	$ 35,165	$ (53,024)
Loss on change in fair value of warrants	$ (29,323)	$ (18,937)

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. The fair value of our commodity derivatives on our consolidated balance sheets were current derivative liabilities of $23.6 million as of December 31, 2022 compared to current derivative liabilities of $40.9 million and non-current derivative liabilities of $17.9 million as of December 31, 2021.

Stock-Based Compensation

During the year ended December 31, 2022, we granted 7,850 restricted stock units (RSU) with an aggregate grant date fair value of $0.2 million and 13,416 stock options with an aggregate grant date fair value of $0.1 million. The RSU grants were made in January 2022 and vest equally each month for thirty months. The stock option grants were made in January 2022 and 100% vest on the first anniversary of the grant date. We recognized stock-based compensation expense of $6.7 million during the year ended December 31, 2022.

During the year ended December 31, 2021, we granted 315,529 RSUs with an aggregate grant date fair value of $8.4 million and 361,418 stock options with an aggregate grant date fair value of $4.1 million. Director RSU grants will 25% vest on each of the following dates: May 27, 2022, September 3, 2022, September 3, 2023, and September 3, 2024 while employee RSU grants will one-third vest on each of the following dates: November 21, 2022, October 1, 2023, and October 1, 2024. The stock option grants will one-third vest on each of the following dates: October 1, 2022, October 1, 2023, and October 1, 2024. We recognized compensation expense of $0.8 million during the year ended December 31, 2021.

On January 6, 2023, in accordance with the provisions allowed under the LTIP, the Compensation Committee adjusted the exercise price of all outstanding stock options to $35.00 per share effective January 31, 2023 to account for the special dividend paid on that date.

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.

Results of Operations

Year Ended December 31, 2022 versus Year Ended December 31, 2021

	Year Ended December 31, 2022	2021	Change	Percent Change [1]
	(In thousands except rig and day amounts, and as otherwise specified)			
Total revenue, before inter-segment eliminations	$ 557,176	$ 690,012	$ (132,836)	(19) %
Total revenue, after inter-segment eliminations	$ 545,525	$ 638,716	$ (93,191)	(15) %
Net income	$ 142,541	$ 48,216	$ 94,325	196 %
Net loss attributable to non-controlling interest	$ (5,828)	$ (12,431)	$ 6,603	(53) %
Net income attributable to Unit Corporation	$ 148,369	$ 60,647	$ 87,722	145 %
Oil and Natural Gas:				
Revenue, before inter-segment eliminations	$ 326,238	$ 272,231	$ 54,007	20 %
Operating costs, before inter-segment eliminations	$ 93,859	$ 83,221	$ 10,638	13 %
Average oil price ($/Bbl)	$ 57.48	$ 50.03	$ 7.45	15 %
Average oil price excluding derivatives ($/Bbl)	$ 94.28	$ 66.50	$ 27.78	42 %
Average NGLs price ($/Bbl)	$ 30.00	$ 23.41	$ 6.59	28 %
Average NGLs price excluding derivatives ($/Bbl)	$ 30.00	$ 23.41	$ 6.59	28 %
Average natural gas price ($/Mcf)	$ 3.65	$ 2.93	$ 0.72	25 %
Average natural gas price excluding derivatives ($/Mcf)	$ 5.79	$ 3.55	$ 2.24	63 %
Oil production (MBbls)	1,281	1,615	(334)	(21) %
NGL production (MBbls)	2,148	2,624	(476)	(18) %
Natural gas production (MMcf)	24,211	29,012	(4,801)	(17) %
Contract Drilling:				
Revenue, before inter-segment eliminations	$ 147,740	$ 76,107	$ 71,633	94 %
Operating costs, before inter-segment eliminations	$ 105,608	$ 60,973	$ 44,635	73 %
Total drilling rigs available for use at the end of the period	18	21	(3)	(14) %
Average number of drilling rigs in use	16.4	10.9	5.5	50 %
Total revenue days	6,001	3,985	2,016	51 %
Average dayrate on daywork contracts ($/day)	$ 23,132	$ 17,987	$ 5,145	29 %
Average dayrate on daywork contracts - BOSS Rigs ($/day)	$ 23,963	$ 19,503	$ 4,460	23 %
Average dayrate on daywork contracts - SCR Rigs ($/day)	$ 19,422	$ 13,981	$ 5,441	39 %
Mid-Stream: [2]				
Revenue, before inter-segment eliminations	$ 83,198	$ 341,674	$ (258,476)	(76) %
Operating costs, before inter-segment eliminations	$ 73,771	$ 286,199	$ (212,428)	(74) %
Gas gathered--Mcf/day	348,859	319,394	29,465	9 %
Gas processed--Mcf/day	146,368	130,000	16,368	13 %
Gas liquids sold--gallons/day	456,700	442,796	13,904	3 %
Corporate and Other:				
General and administrative expense, before inter-segment eliminations	$ 24,033	$ 21,399	$ 2,634	12 %
Other income (expense):				
Interest income	$ 2,642	$ 2	$ 2,640	NM
Interest expense	$ (447)	$ (4,266)	$ 3,819	(90) %
Reorganization items	$ (127)	$ (4,294)	$ 4,167	97 %
Loss on derivatives	$ (63,610)	$ (97,615)	$ 34,005	35 %
Loss on change in fair value of warrants	$ (29,323)	$ (18,937)	$ (10,386)	55 %
Loss on deconsolidation of Superior	$ (13,141)	$ —	$ (13,141)	— %
Income tax expense, net	$ 333	$ 173	$ 160	92 %
Average interest rate on long-term debt outstanding	2.2 %	6.4 %	(4.2)%	(66) %
Average long-term debt outstanding	$ 3,143	$ 46,222	$ (43,079)	(93) %

1. NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.
2. Mid-Stream activity and metrics shown in this table for the year ended December 31, 2022 reflect Superior activity on a consolidated basis for the two months prior to March 1, 2022.

Oil and Natural Gas

Oil and natural gas revenues increased $54.0 million or 20% during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to higher commodity prices, partially offset by lower production volumes. Including derivatives settled, average oil prices increased 15% to $57.48 per barrel, average natural gas prices increased 25% to $3.65 per Mcf, and NGLs prices increased 28% to $30.00 per barrel. Oil production decreased 21%, natural gas production decreased 17%, and NGLs production decreased 18%. The decrease in volumes was primarily due to normal well production declines and divestitures of producing properties which have not been offset by new drilling or acquisitions.

Oil and natural gas operating costs increased $10.6 million or 13% during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to higher production tax expenses due to increased revenues, higher employee compensation and separation benefits, and higher lease operating expenses.

Contract Drilling

Contract drilling revenues increased $71.6 million or 94% during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to a 50% increase in the average number of drilling rigs in use to 16.4 during the year ended December 31, 2022 as well as increases to the average dayrates on daywork contracts of 23% and 39% on BOSS rigs and SCR rigs, respectively.

Contract drilling operating costs increased $44.6 million or 73% during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to an increase in the average number of operating rigs, higher employee compensation, and $6.7 million of transportation and start up costs associated with bringing stacked rigs back into service.

Total rigs available for use was reduced from 21 to 18 as of December 31, 2022 reflecting the current market outlook for utilization of our SCR rigs.

Mid-Stream

Mid-Stream revenues decreased $258.5 million or 76% during the year ended December 31 2022 compared to the year ended December 31, 2021 primarily due to the absence of activity subsequent to March 1, 2022 as a result of the deconsolidation of Superior, partially offset by higher gas, NGL, and condensate prices as well as higher volumes during the consolidated period. Gas processed volumes per day increased 13% while gas gathered volumes per day increased 9% between the comparative periods primarily due to connecting new wells as well as new volumes from the processing plant and gathering system acquired in November 2021.

Operating costs decreased $212.4 million or 74% during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to the absence of activity subsequent to March 1, 2022 as a result of the deconsolidation of Superior, partially offset by higher gas, NGL, and condensate prices as well as higher purchase volumes related to the processing plant and gathering system acquired in November 2021.

General and Administrative

General and administrative expenses increased $2.6 million or 12% during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to an increase in stock-based compensation, partially offset by lower insurance expense.

Interest Income

Interest income increased $2.6 million during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to higher average cash equivalents held as well as higher average interest rates during the year ended December 31, 2022 compared to the year ended December 31, 2021.

Interest Expense

Interest expense decreased $3.8 million during the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to a 93% decrease in average long-term debt outstanding and a decrease in the average interest rate from 6.4% during the year ended December 31, 2021 to 2.2% during the year ended December 31, 2022. Our average debt outstanding decreased $43.1 million during the year ended December 31, 2022 compared the year ended December 31, 2021 primarily due to payments made under the Exit credit agreement and the deconsolidation of Superior's outstanding long-term debt, partially offset by borrowings under the Superior credit agreement prior to deconsolidation.

Reorganization Items

Reorganization items represent any of the expenses, gains, and losses incurred subsequent to and as a direct result of the Chapter 11 proceedings.

Loss on Derivatives

The $34.0 million favorable change in loss on derivatives between the comparative first twelve months of 2022 and 2021 is primarily due to favorable pricing changes on unsettled commodity derivative positions and new commodity derivative positions executed during the second quarter of 2022, partially offset by higher settlement payments driven by higher average pricing.

Loss on Change in Fair Value of Warrants

The $10.4 million unfavorable change in loss on change in fair value of warrants between the years ended December 31, 2022 and 2021 is primarily due to changes in the underlying assumptions used to estimate the fair value, including entity value, volatility, duration to exercise, and other inputs.

Loss on Deconsolidation of Superior

Loss on deconsolidation of $13.1 million during the year ended December 31, 2022 represents the loss recognized on the March 1, 2022 deconsolidation of Superior.

Income Tax Expense

Income tax expense was $0.3 million during the year ended December 31, 2022 compared to $0.2 million during the year ended December 31, 2021 primarily due to the utilization of our net deferred tax assets.

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 our contract drilling rigs and services. This increase in demand affects the dayrates we can obtain for our contract drilling services. During periods of higher demand for our drilling rigs we have experienced increases in labor costs and the costs of services to support our drilling rigs. Historically, during this same period, when oil, NGLs, and natural gas prices declined, labor rates did not come back down to the levels existing before the increases. 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 our material and labor costs. Increases in dayrates for drilling rigs also increase the cost of drilling our oil and natural gas properties. How inflation will affect us in the future will depend on increases, if any, realized in our drilling rig rates, the prices we receive for our oil, NGLs, and natural gas, and the rates we receive for gathering and processing natural gas.

Item 7A. 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 probably continue to do so. The price of oil, NGLs, and natural gas also affects both the demand for our drilling rigs and the amount we can charge for our drilling rigs. Based on our production for the year ended December 31, 2022, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $0.2 million per month ($2.4 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 ($1.3 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 $0.2 million per month ($2.2 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.

At December 31, 2022, these non-designated hedges were outstanding:

Remaining Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'23 - Feb'23	Natural gas - swap	27,627 MMBtu/day	$9.14	IF - NYMEX (HH)
Jan'23 - Dec'23	Natural gas - swap	22,000 MMBtu/day	$2.46	IF - NYMEX (HH)
Jan'23 - Mar'23	Natural gas - basis swap	25,000 MMBtu/day	$(0.17)	NGLP TEXOK
Jan'23 - Feb'23	Crude oil - swap	1,339 Bbl/day	$95.40	WTI - NYMEX
Jan'23 - Dec'23	Crude oil - swap	1,300 Bbl/day	$43.60	WTI - NYMEX

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 2022, a 1% change in the average effective interest rate on these holdings during 2022 would change our annual pre-tax cash flow by approximately $1.4 million. Borrowings under our Exit credit agreement also bear interest at variable interest rates. We had no outstanding borrowings under this facility as of December 31, 2022.

Item 8. Financial Statements and Supplementary Data

Index to Financial Statements
Unit Corporation and Subsidiaries

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Unit Corporation

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Unit Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity, and cash flows for each of the two years in the period ended December 31, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022, and 2021, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

Deconsolidation of a variable interest entity
As discussed in Note 19 to the financial statements, the Company changed its method of accounting for a variable interest entity from consolidating its activities to accounting for the investee as an equity method investment in 2022.

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

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

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

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

Proved oil and natural gas property and depletion— oil and natural gas reserve quantities and future cash flows
As described further in Note 2 to the financial statements, the Company accounts for its oil and natural gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense. To estimate the volume of proved oil and gas reserve quantities and future cash flows, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties. In addition, the estimation of proved oil and gas reserve quantities is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense. We identified the estimation of proved reserves of oil and natural gas properties to be a critical audit matter due to its impact on depletion expense.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of management subjectivity, necessary to estimate the volume and future revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense. In turn, auditing those inputs and assumptions required complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We evaluated the knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the proved reserve volumes, and read the reserve report prepared by the reservoir engineering specialists.
- We tested the accuracy of the Company's depletion calculations that included these proved reserves.
- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other financial inputs and assumptions, including certain assumptions that are derived from the Company's accounting records. These assumptions included historical pricing differentials, future operating costs, estimated future capital costs, and ownership interests.
- We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis. Specifically, our audit procedures involved testing management's assumptions as follows:
    - We compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials.
    - We evaluated the models used to estimate the future operating costs at year-end and compared the models to historical operating costs.
    - We evaluated the ownership interests used in the reserve report by inspecting lease and title records on a sample basis.
    - We applied analytical procedures to the reserve report by comparing the reserve report to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

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

Tulsa, Oklahoma
March 17, 2023

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2022	2021
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 213,975	$ 64,140
Accounts receivable, net of allowance for credit losses of $2,688 and $2,511 at December 31, 2022 and December 31, 2021, respectively	57,776	87,248
Prepaid expenses and other	3,718	5,542
Total current assets	275,469	156,930
Property and equipment:		
Oil and natural gas properties, on the full cost method:		
Proved properties	176,986	225,014
Unproved properties not being amortized	6,953	422
Drilling equipment	76,640	66,058
Gas gathering and processing equipment	—	274,748
Transportation equipment	2,628	4,550
Other	8,691	8,631
	271,898	579,423
Less accumulated depreciation, depletion, amortization, and impairment	96,605	128,880
Net property and equipment	175,293	450,543
Equity method investment (Note 19)	1,658	—
Right of use asset (Note 18)	6,551	12,445
Other assets	10,284	9,559
Total assets [1]	$ 469,255	$ 629,477

1. Unit Corporation no longer consolidates the balance sheet of Superior Pipeline Company, L.L.C. (Superior) as of December 31, 2022, as discussed in Note 2 - Summary Of Significant Accounting Policies and Note 19 - Superior Investment. Unit Corporation's consolidated total assets as of December 31, 2021 included current and long-term assets of Superior of $61.1 million and $229.5 million, respectively, which could only be used to settle obligations of Superior. Unit Corporation's consolidated cash and cash equivalents of $64.1 million as of December 31, 2021 included $17.2 million held by Superior.

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (Continued)

	December 31,	
	2022	2021
	(In thousands except share and par value amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 20,356	$ 58,625
Accrued liabilities (Note 8)	18,716	22,450
Current operating lease liability (Note 18)	1,605	3,791
Current derivative liabilities (Note 16)	23,566	40,876
Warrant liability (Note 16)	—	19,822
Current portion of other long-term liabilities (Note 9)	3,989	5,574
Total current liabilities	68,232	151,138
Long-term debt (Note 9)	—	19,200
Non-current derivative liabilities (Note 16)	—	17,855
Operating lease liability (Note 18)	5,035	8,677
Other long-term liabilities (Note 9)	33,362	32,939
Deferred income taxes (Note 12)	—	—
Commitments and contingencies (Note 20)		
Shareholders' equity:		
Common stock, $0.01 par value, 25,000,000 shares authorized: 12,100,356 shares issued and 9,627,964 shares outstanding as of December 31, 2022, and 12,000,000 issued and outstanding as of December 31, 2021	121	120
Treasury stock	(79,399)	(51,965)
Capital in excess of par value	252,464	198,171
Retained earnings	189,440	41,071
Total shareholders' equity attributable to Unit Corporation	362,626	187,397
Non-controlling interests in consolidated subsidiaries	—	212,271
Total shareholders' equity	362,626	399,668
Total liabilities and shareholders' equity [1]	$ 469,255	$ 629,477

1. Unit Corporation no longer consolidates the balance sheet of Superior as of December 31, 2022, as discussed in Note 2 - Summary Of Significant Accounting Policies and Note 19 - Superior Investment. Unit Corporation's consolidated total liabilities as of December 31, 2021 included current and long-term liabilities of Superior of $42.3 million and $21.2 million, respectively. All of Unit Corporation's consolidated long-term debt of $19.2 million as of December 31, 2021 was held by Superior.

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,	
	2022	2021
	(In thousands except per share amounts)	
Revenues:		
Oil and natural gas	$ 315,482	$ 224,232
Contract drilling	147,370	76,107
Gas gathering and processing	82,673	338,377
Total revenues	545,525	638,716
Expenses:		
Operating costs:		
Oil and natural gas	93,350	79,924
Contract drilling	105,387	60,973
Gas gathering and processing	62,388	234,684
Total operating costs	261,125	375,581
Depreciation, depletion, and amortization	24,143	64,326
Impairments (Note 3)	—	10,673
General and administrative	24,644	24,915
Gain on disposition of assets	(8,367)	(10,877)
Total operating expenses	301,545	464,618
Income from operations	243,980	174,098
Other income (expense):		
Interest income	2,642	2
Interest expense	(447)	(4,266)
Loss on derivatives (Note 16)	(63,610)	(97,615)
Loss on change in fair value of warrants (Note 17)	(29,323)	(18,937)
Loss on deconsolidation of Superior (Note 19)	(13,141)	—
Reorganization items, net	(127)	(4,294)
Other, net	2,900	(599)
Total other income (expense)	(101,106)	(125,709)
Income before income taxes	142,874	48,389
Income tax expense (Note 12):		
Current	333	173
Deferred	—	—
Total income taxes	333	173
Net income	142,541	48,216
Net loss attributable to non-controlling interest	(5,828)	(12,431)
Net income attributable to Unit Corporation	$ 148,369	$ 60,647
Net income attributable to Unit Corporation per common share (Note 7):		
Basic	$ 15.03	$ 5.32
Diluted	$ 14.78	$ 5.26

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

UNIT CORPORATION AND SUBSIDIARIES
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)	Non-controlling Interest in Consolidated Subsidiaries	Total
			(In thousands)			
Balances, December 31, 2020	$ 120	$ —	$ 197,242	$ (18,140)	$ 246,371	$ 425,593
Net income (loss)	—	—	—	60,647	(12,431)	48,216
Stock-based compensation	—	—	929	—	31	960
Distributions to non-controlling interests	—	—	—	—	(23,136)	(23,136)
Balance correction (Note 2)	—	—	—	(1,436)	1,436	—
Repurchases of common stock	—	(51,965)	—	—	—	(51,965)
Balances, December 31, 2021	$ 120	$ (51,965)	$ 198,171	$ 41,071	$ 212,271	$ 399,668
Net income (loss)	$ —	$ —	$ —	148,369	(5,828)	142,541
Stock-based compensation	—	—	6,718	—	—	6,718
Vesting of restricted stock units, net of shares withheld for employee taxes	1	—	(1,243)	—	—	(1,242)
Exercise of stock options, net of shares withheld for taxes and exercise price	—	—	(327)	—	—	(327)
Distributions to non-controlling interests	—	—	—	—	(9,479)	(9,479)
Deconsolidation of Superior	—	—	—	—	(196,964)	(196,964)
Warrant liability reclassification	—	—	49,145	—	—	49,145
Repurchases of common stock	—	(27,434)	—	—	—	(27,434)
Balances, December 31, 2022	$ 121	$ (79,399)	$ 252,464	$ 189,440	$ —	$ 362,626

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 142,541	$ 48,216
Adjustments to reconcile net income operating activities:		
Depreciation, depletion, and amortization	24,143	64,326
Impairments (Note 3)	—	10,673
Loss on derivatives (Note 16)	63,610	97,615
Cash payments on derivatives settled (Note 16)	(98,775)	(44,591)
Loss on change in fair value of warrants (Note 16)	29,323	18,937
Gain on disposition of assets	(8,367)	(10,877)
Loss on deconsolidation of Superior (Note 19)	13,141	—
Stock-based compensation plans (Note 15)	6,718	929
Other, net	3,382	5,855
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(10,699)	(31,034)
Prepaid expenses and other	(2,064)	(4,953)
Accounts payable	(3,234)	23,141
Accrued liabilities	(265)	(3,331)
Income taxes	127	1,160
Contract advances	(160)	(97)
Net cash provided by operating activities	$ 159,421	$ 175,969
INVESTING ACTIVITIES:		
Capital expenditures	(30,386)	(30,305)
Deconsolidated Superior cash and cash equivalents (Note 19)	(10,119)	—
Other acquisitions	—	(13,000)
Proceeds from disposition of property and equipment	69,401	79,510
Net cash provided by investing activities	$ 28,896	$ 36,205
FINANCING ACTIVITIES:		
Borrowings under line of credit	$ 4,800	$ 65,300
Payments under line of credit	(4,800)	(145,100)
Net payments on finance leases	—	(3,216)
Employee taxes paid by withholding shares	(1,569)	—
Distributions to non-controlling interest (Note 19)	(9,479)	(23,136)
Repurchase of common stock (Note 6)	(27,434)	(51,965)
Bank overdrafts	—	(2,631)
Net cash used in financing activities	$ (38,482)	$ (160,748)
Net increase in cash and cash equivalents	149,835	51,426
Cash and cash equivalents, beginning of period	64,140	12,714
Cash and cash equivalents, end of period	$ 213,975	$ 64,140

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

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Supplemental disclosure of cash flow information:		
Cash paid for:		
Interest paid (net of capitalized)	$ 589	$ 4,769
Income taxes	$ 173	$ —
Reorganization items	$ (50)	$ 4,283
Changes in accounts payable and accrued liabilities related to purchases of property and equipment	$ 3,062	$ (1,249)
Non-cash reductions (increases) to oil and natural gas properties related to asset retirement obligations	$ (4,324)	$ (4,412)
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	$ 8,984	$ 2,218

The accompanying notes are an integral part of the 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, one or more of its subsidiaries. References to our mid-stream segment refers to Superior of which we own 50%.

We are primarily engaged in the development, acquisition, and production of oil and natural gas properties, the land contract drilling of natural gas and oil wells, and the buying, selling, gathering, processing, and treating of natural gas. Our operations are all located in the United States and are organized as the following three reporting segments:

Oil and Natural Gas. Carried out by our subsidiary, Unit Petroleum Company (UPC), we develop, acquire, and produce oil and natural gas properties for our own account. Our producing oil and natural gas properties, unproved properties, and related assets are primarily located in Oklahoma and Texas, and to a lesser extent, in Arkansas, Kansas, Louisiana, and North Dakota.

Contract Drilling. Carried out by our subsidiary, Unit Drilling Company (UDC), we drill onshore oil and natural gas wells for a wide range of other oil and natural gas companies as well as for our own account. Our drilling operations are primarily located in Oklahoma, Texas, New Mexico, Wyoming, and North Dakota.

Mid-Stream. Carried out by Superior of which we own 50%. Superior buys, sells, gathers, transports, processes, and treats natural gas for UPC and for third parties. Mid-Stream operations are primarily located in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. We consolidated the financial position, operating results, and cash flows of Superior prior to March 1, 2022, on which date the Master Services and Operating Agreement (MSA) was amended and restated, with the result that we no longer consolidate Superior's financial position, operating results, and cash flows during periods subsequent to March 1, 2022. Accordingly, the 2022 consolidated financial statements and notes reflect Superior activity on a consolidated basis for the two months prior to March 1, 2022. See Note 19 – Superior Investment for more information on the Superior investment and consolidation conclusions. All intercompany transactions and accounts between consolidated entities have been eliminated, including activity between Unit and Superior during the two months prior to March 1, 2022. Affiliate transactions and accounts between Unit and Superior subsequent to March 1, 2022 are not eliminated.

During 2021, management identified an error in the initial allocation of equity between Unit Corporation and non-controlling interests as of the September 3, 2020 fresh start accounting date. The impact of the error was not material to any of our prior period financial statements and the error was corrected with one-time adjustment during the year ended December 31, 2021. As a result, during the year ended December 31, 2021, retained earnings (deficit) was reduced by $1.4 million with a corresponding decrease to non-controlling interest in consolidated subsidiaries.

Certain amounts presented for prior periods have been reclassified to conform to current year presentation. There was no impact from these reclassifications to consolidated net income or shareholders' equity.

We evaluated our disclosure of subsequent events through March 17, 2023, 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;
- fair value of commodity derivative assets and liabilities;
- fair value of the warrant liability;

- fair value of stock-based compensation grants or modifications;
- workers' compensation liabilities;
- fair value of our retained investment in Superior;
- 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, 2022 or December 31, 2021.

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 which 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, 2022 and 2021.

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 $1.49 and $2.67 per Boe for the years ended December 31, 2022 and 2021, respectively.

Our contract drilling segment may provide drilling services for our oil and natural gas segment. Revenues and expenses from these services are eliminated in our consolidated statements of operations, with any recognized profit reducing the cost of our oil and natural gas properties. We eliminated contract drilling revenues and capitalized oil and natural gas costs of $0.1 million during the year ended December 31, 2022. There were no intercompany drilling services provided for elimination during the year ended December 31, 2021.

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.

Drilling equipment, gas gathering and processing equipment, transportation equipment, and other property and equipment. Drilling equipment, gas gathering and processing equipment, transportation equipment, and other property and equipment are carried at cost less accumulated depreciation. Renewals and enhancements are capitalized while repairs and maintenance are expensed. We depreciate all drilling assets utilizing the straight-line method over the estimated useful lives of the assets, typically ranging from four to ten years. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets, typically ranging from three 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 a an asset, declines in commodity prices, periods of relatively low drilling rig utilization, declining revenue or cash margin per day, or overall unfavorable 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.

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. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, 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, 2022 and 2021.

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. Leases with an initial term of 12 months or less are not recorded as a lease right-of-use asset and liability.

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. Our mid-stream investment has property and equipment at locations leased or under right of way agreements which may require asset removal or site restoration, however, prior to the deconsolidation of Superior, we were not able to reasonably measure the fair value of the obligations as the potential settlement dates were indeterminable.

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.

Commodity Derivatives. All commodity derivatives are recognized on the consolidated balance sheets as either an asset or liability measured at fair value and all our commodity derivative counterparties are subject to master netting agreements. 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 settlement are reported in loss 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 assesses 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 $3.5 million and a liability of $4.3 million as of December 31, 2022 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.

Warrant Liability. Prior to the determination of the initial exercise price, we recognized the fair value of the warrants as a derivative liability on our consolidated balance sheets with changes in the liability reported as loss on change in fair value of warrants in our consolidated statements of operations. On April 7, 2022, the Company delivered notice of the initial $63.74 exercise price resulting in the warrants meeting the definition of an equity instrument. Accordingly, we recognized the change in the fair value of the warrant liability in our unaudited condensed consolidated statements of operations and reclassified the $49.1 million warrant liability to capital in excess of par value on the unaudited condensed consolidated balance sheets as of April 7, 2022. The warrants will continue to be reported as capital in excess of par value and are no longer subject to future fair value adjustments.

NOTE 3 - IMPAIRMENTS

Oil and Natural Gas Properties and Contract Drilling

There were no impairments recorded during the years ended December 31, 2022 or 2021.

Mid-Stream

2022

There were no impairments recorded during the year ended December 31, 2022.

2021

In December 2021, we determined that the carrying value of a gathering system in Pennsylvania was not recoverable and exceeded its estimated fair value due to unfavorable forecasted economics. We recorded non-cash impairment charges of $10.7 million based on the estimated fair value of the asset group. These charges are included within impairments in our consolidated statements of operations.

NOTE 4 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Our revenue streams are reported under three segments: oil and natural gas, contract drilling, and mid-stream which is consistent with how we report our segment revenue in Note 22 – Industry Segment Information. Revenue from the oil and natural gas segment is from sales of our oil and natural gas production. Revenue from the contract drilling segment comes from contracting with upstream companies to drill an agreed-on number of wells or provide drilling rigs and services over an agreed-on period. Revenues from the mid-stream segment are generated from the fees earned for gas gathering and processing services provided to a customer or by selling of hydrocarbons to other mid-stream companies.

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. Revenues from oil and natural gas sales are recognized when the customer obtains control of the sold product which typically occurs at the point of delivery to the customer.

Certain costs, as either a deduction from revenue or as an expense, are determined based on when control of the commodity is transferred to our customer, which would affect our total revenue recognized, but will not affect gross profit. For example, gathering, processing and transportation costs are included as part of the contract price with the customer on transfer of control of the commodity are included in the transaction price, while costs incurred while we are in control of the commodity represent operating costs.

Contract Drilling Revenue

Contract drilling revenues and expenses are primarily recognized as services are performed and collection is reasonably assured. Payments for mobilization and demobilization activities do not relate to a distinct good or service within the contract, but are recognized as revenue when received as deferral for ratable recognition over the contract term is not material to the consolidated financial statements. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred and any reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs.

Most of our drilling contracts have a term of one year or less and the remaining performance obligations under the contracts without a fixed term are not material.

Mid-Stream Revenue

The typical revenue contracts used by this segment are gas gathering and processing agreements as well as product sales. Superior recognizes sales revenue at the point in time when control transfers to the purchaser, typically at a specified delivery point, based on the contractually agreed upon fixed or index-based price received. Contracts for gas gathering and processing services may include terms for demand fees or shortfall fees. Demand fees or shortfall fees exist in arrangements where a customer agrees to pay a fixed fee for a contractually agreed upon pipeline capacity or shortfall fees for any minimum volumes not utilized, which create performance obligations for each individual period of reservation. Revenue for these fees is recognized once the services have been completed, the customer no longer has access to the contracted capacity, or the likelihood of the customer exercising all or a portion of their remaining rights becomes remote.

Contract Assets and Liabilities

The table below presents the changes in our contract asset and contract liability balances during periods indicated:

	Classification on the consolidated balance sheets	December 31, 2022	December 31, 2021	Change
		(In thousands)		
Assets				
Current contract assets	Prepaid expenses and other	$ —	$ 174	$ (174)
Non-current contract assets	Other assets	—	—	—
Total contract assets		$ —	$ 174	$ (174)
Liabilities				
Current contract liabilities	Current portion of other long-term liabilities	$ 24	$ 1,588	$ (1,564)
Non-current contract liabilities	Other long-term liabilities	176	200	(24)
Total contract liabilities		200	1,788	(1,588)
Contract assets (liabilities), net		$ (200)	$ (1,614)	$ 1,414

NOTE 5 – ACQUISITIONS AND DIVESTITURES

Oil and Natural Gas

The Company initiated an asset divestiture program at the beginning of 2021 to sell certain non-core oil and gas properties and reserves (the Divestiture Program). On October 4, 2021, the Company announced that it was expanding the Divestiture Program to include the potential sale of additional properties, including up to all of UPC's oil and gas properties and reserves, and on January 20, 2022, the Company announced that it had retained a financial advisor and launched the process. On June 10, 2022, the Company announced that it had ended its engagement with the financial advisor and terminated the process. During the process, the Company entered into an agreement to sell its Texas Gulf Coast oil and gas properties.

On July 1, 2022, the Company closed on the sale of certain wells and related leases near the Texas Gulf Coast for cash proceeds of $45.4 million, net of customary closing and post-closing adjustments based on an effective date of April 1, 2022. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On March 8, 2022, the Company closed on the sale of certain non-core wells and related leases located near the Oklahoma Panhandle for cash proceeds of $3.6 million, net of customary closing and post-closing adjustments based on an effective date of December 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On August 16, 2021, the Company closed on the sale of substantially all of our wells and related leases located near Oklahoma City, Oklahoma for cash proceeds of $16.1 million, net of customary closing and post-closing adjustments based on an effective date of August 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

On May 6, 2021, the Company closed on the sale of substantially all of our wells and the leases related thereto located in Reno and Stafford Counties, Kansas for cash proceeds of $7.3 million, net of customary closing and post-closing adjustments based on an effective date of February 1, 2021. These proceeds reduced the net book value of our full cost pool with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool.

Net proceeds for the sale of other non-core oil and natural gas assets totaled $7.7 million and $5.0 million during the twelve months ended December 31, 2022 and 2021, 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.

Contract Drilling

Proceeds for the sale of non-core contract drilling assets totaled $12.8 million and $12.7 million during the twelve months ended December 31, 2022 and 2021, respectively. These proceeds resulted in net gains of $8.4 million and $10.1 million during the twelve months ended December 31, 2022 and 2021, respectively. The net gains are presented within gain on disposition of assets in the consolidated statements of operations.

Mid-Stream

In November 2021, Superior closed on an acquisition for $13.0 million, subject to customary closing and post-closing adjustments, that included a cryogenic processing plant, approximately 1,620 miles of low-pressure gathering pipeline, and related compressor stations located in southern Kansas. The transaction was accounted for as an asset acquisition.

There was no significant divestiture activity during the years ended December 31, 2022 and 2021.

Corporate and Other

On September 17, 2021, we closed the sale of our corporate headquarters building and land for $35.0 million, subject to customary closing and post-close adjustments resulting in a gain of $0.9 million net of $2.2 million of transaction costs. In conjunction with the closing, we entered into a multi-year lease for a portion of the building.

NOTE 6 – SHAREHOLDERS' EQUITY AND DIVIDENDS

Common Stock

On September 3, 2020 (Emergence Date), the Company emerged from Chapter 11 bankruptcy and issued 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.

All shares of New Common Stock are subject to the transfer restrictions in the Company’s Amended and Restated Certificate of Incorporation (Charter). Article XIV of the Charter provides that, subject to the exceptions provided in Article XIV, any attempted transfer of the Company's common stock will be prohibited and void ab initio if (i) because of the transfer, any person becomes a Substantial Stockholder (as defined below) other than by reason of Treasury Regulations section 1.382-2T(j)(3) or (ii) the Percentage Stock Ownership (as defined in the Charter) interest of any Substantial Stockholder will be increased. A "Substantial Stockholder” means a person with a Percentage Stock Ownership of 4.75% or more.

Common Stock Repurchases

The table below presents the common stock repurchase activity during the periods indicated:

	Shares	Purchase Price	Price per Share
	(in thousands, except for per share amounts)		
2022			
Repurchase Program [(1)]	522	$ 27,421	$ 52.49
Total Repurchases	522	$ 27,421	$ 52.49
2021			
Repurchase Program [(1)]	1,272	$ 41,430	$ 32.57
Lender Repurchases [(2)]	600	$ 9,000	$ 15.00
Other Repurchases [(3)]	78	$ 1,487	$ 19.07
Total Repurchases	1,950	$ 51,917	$ 26.62

1) In June 2021, the Company's Board of Directors (the Board) authorized repurchasing up to $25.0 million of the Company's outstanding common stock. The Board subsequently authorized increases to the authorized repurchases up to $50.0 million in October 2021 and then up to $100.0 million in June 2022. The repurchases are made through open market purchases, privately negotiated transactions, or other available means. The Company has no obligation to repurchase any shares under the repurchase program and may suspend or discontinue it at any time without prior notice. As of December 31, 2022, we had repurchased a total of 1,794,392 shares under the repurchase program at an average share price of $38.37 for an aggregate purchase price of $68.9 million.

2) In June 2021, we repurchased our common stock from the Lenders (as defined in Note 9 - Long-Term Debt and Other Long-Term Liabilities) which received these shares as an exit fee during our reorganization.

3) During the year ended December 31, 2021, we repurchased shares in a privately negotiated transaction which was not part of the repurchase program.

The cumulative number of shares repurchased as of December 31, 2022 totaled 2,472,392. The cash purchase price and any direct acquisition costs are reflected as treasury stock 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 is 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, 2022, the Company had authorized 1,822,231 warrants and none had been exercised.

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 Effective Date (as defined in the Plan) 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".

See Note 16 - Derivatives for more information on how the warrants are treated in our consolidated financial statements.

Dividends

There were no dividends paid by the Company during the years ended December 31, 2022 and 2021. On January 31, 2023, the Company paid a special cash dividend of $10.00 per share totaling $96.1 million to stockholders of record as of the close of business on January 20, 2023.

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:

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
Year ended December 31, 2022			
Basic earnings attributable to Unit Corporation per common share	$ 148,369	9,874	$ 15.03
Effect of dilutive restricted stock units and stock options (1)	—	164	(0.25)
Diluted earnings attributable to Unit Corporation per common share	$ 148,369	10,038	$ 14.78
Year ended December 31, 2021			
Basic earnings attributable to Unit Corporation per common share	$ 60,647	11,405	$ 5.32
Effect of dilutive restricted stock units (2)	—	115	(0.06)
Diluted loss attributable to Unit Corporation per common share	$ 60,647	11,520	$ 5.26

1. The diluted earnings per share calculation for the year ended December 31, 2022 excludes the effects related to 355,827 average outstanding stock options with a $45.00 exercise price and 1,822,206 average warrants with a $63.74 exercise price because their inclusion would be antidilutive.
2. The diluted earnings per share calculation for the year ended December 31, 2021 excludes the effect related to 361,418 average outstanding stock options with a $45.00 exercise price because their inclusion would be antidilutive.

NOTE 8 – ACCRUED LIABILITIES

The table below presents the components of accrued liabilities:

	As of December 31, 2022	2021
	(In thousands)	
Employee costs	$ 5,905	$ 10,005
Lease operating expenses	3,383	3,451
Capital expenditures	6,359	3,962
Taxes	1,035	3,320
Interest payable	40	296
Other	1,994	1,416
Total accrued liabilities	$ 18,716	$ 22,450

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,	
	2022	2021
	(In thousands)	
Long-term debt:		
Exit credit agreement	—	—
Superior credit agreement [(1)]		19,200

1. Unit Corporation no longer consolidates the balance sheet of Superior as of December 31, 2022, as discussed in Note 2 - Summary Of Significant Accounting Policies and Note 19 - Superior Investment.

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 Effective 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 (in such capacity, the Administrative Agent). The maturity date of borrowings under the Exit credit agreement is March 1, 2024. The Exit credit agreement is 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.

Prior to the November 1, 2022 amendment described below, Revolving Loans and Term Loans (each as defined in the Exit credit agreement) were able to be Eurodollar Loans or ABR Loans (each as defined in the Exit credit agreement). Revolving Loans that were Eurodollar Loans bore interest at a rate per annum equal to the Adjusted LIBO Rate (as defined in the Exit credit agreement) for the applicable interest period plus 525 basis points while Revolving Loans that were ABR Loans bore interest at a rate per annum equal to the Alternate Base Rate (as defined in the Exit credit agreement) plus 425 basis points. Term Loans that were Eurodollar Loans bore interest at a rate per annum equal to the Adjusted LIBO Rate for the applicable interest period plus 625 basis points while Term Loans that were ABR Loans bore interest at a rate per annum equal to the Alternate Base Rate plus 525 basis points.

On April 6, 2021, the Company finalized the first amendment to the Exit credit agreement. Under the first amendment, the Company reaffirmed its borrowing base of $140.0 million of the RBL Facility, amended certain financial covenants, and received less restrictive terms, among others, as it relates to the disposition of assets and the use of proceeds from those dispositions.

On July 27, 2021, the Company finalized the second amendment to the Exit credit agreement. Under the second amendment, the Company obtained confirmation that the Term Loan had been paid in full prior to the amendment date and received one-time waivers related to the disposition of assets.

On October 19, 2021, the Company finalized the third amendment to the Exit credit agreement. Under the third amendment, the Company requested, and was granted, a reduction in the RBL Facility borrowing base from $140.0 million to $80.0 million in addition to less restrictive terms as it relates to capital expenditures, required hedges, and the use of proceeds from the disposition of certain assets, while also amending certain financial covenants.

On March 30, 2022, the RBL Facility borrowing base of $80.0 million was reaffirmed.

On July 1, 2022, the RBL Facility borrowing base was automatically reduced to $31.3 million as a result of closing the Texas Gulf Coast properties sale discussed in Note 5 - Acquisitions And Divestitures.

On November 1, 2022, the Company finalized the fourth amendment to the Exit credit agreement. Under the fourth amendment, (i) the RBL Facility borrowing base was increased to $35.0 million, (ii) the lenders party to the agreement were revised to only BOKF, NA dba Bank of Oklahoma, and (iii) the Eurodollar Loan borrowing option was amended to a secured overnight financing rate (SOFR) option. Subsequent to the fourth amendment, Revolving Loans are able to be SOFR Loans or ABR Loans (each as defined in the Exit credit agreement). Revolving Loans that are SOFR Loans bear interest at a rate per annum equal to the Adjusted Term SOFR Rate (as defined in the Exit credit agreement) for the applicable interest period plus 525 basis points while Revolving Loans that are ABR Loans bear interest at a rate per annum equal to the Alternate Base Rate plus 425 basis points.

The Exit credit agreement requires the Company to comply with certain financial ratios, including: the Net Leverage Ratio (as defined in the Exit credit agreement) as of the last day of any fiscal quarter cannot be greater than 3.25 to 1.00, the Current Ratio (as defined in the Exit credit agreement) as of the last day of any fiscal quarter cannot be less than 1.00 to 1.00, and the Interest Coverage Ratio (as defined in the Exit credit agreement) as of the last day of any fiscal quarter cannot be less than 2.50 to 1.00. The Exit credit agreement also contains provisions, among others, that limit certain capital expenditures, and require certain hedging activities. The Exit credit agreement further requires 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 financial statements within 90 days after the end of each fiscal year. As of December 31, 2022, the Company was in compliance with these covenants.

As of December 31, 2022, we had no long-term borrowings and $2.7 million of letters of credit outstanding under the Exit credit agreement.

Superior Credit Agreement. On May 10, 2018, Superior entered into a five-year, $200.0 million senior secured revolving credit facility with an option to increase the credit amount up to $250.0 million, subject to certain conditions (Superior credit agreement). The amounts borrowed under the Superior credit agreement bore annual interest at a rate, at Superior's option, equal to (a) LIBOR plus the applicable margin of 2.00% to 3.25% or (b) the alternate base rate (greater of (i) the federal funds rate plus 0.5%, (ii) the prime rate, and (iii) the Thirty-Day LIBOR Rate (as defined in the Superior credit agreement)) plus the applicable margin of 1.00% to 2.25%.

On April 29, 2022, Superior entered into an Amended and Restated Credit Agreement for a four-year, $135.0 million senior secured revolving credit facility with an option to increase the credit amount up to $200.0 million, subject to certain conditions (Amended Superior credit agreement). The amounts borrowed under the Amended Superior credit agreement bear annual interest at a rate, at Superior's option, equal to (a) Adjusted Term SOFR plus the Term Benchmark Applicable Margin of 2.75% to 3.75% or (b) the Base Rate (defined as the greater of (i) the Prime Rate, (ii) the 30 day Adjusted Term SOFR plus 1.0%, and (iii) the federal funds rate plus 0.5%) plus the Base Rate Applicable Margin of 1.75% to 2.75%. The obligations under the Amended Superior credit agreement are secured by, among other things, mortgage liens on certain of Superior's processing plants and gathering systems. Unit is not a party to and does not guarantee the Amended Superior credit agreement.

Other Long-Term Liabilities

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

	As of December 31,	
	2022	2021
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 23,440	$ 25,688
Workers' compensation	8,344	7,925
Contract liabilities	200	1,788
Separation benefit plans	1,110	2,022
Gas balancing liability	4,257	1,090
	37,351	38,513
Less: current portion	3,989	5,574
Total other long-term liabilities	$ 33,362	$ 32,939

NOTE 10 – ASSET RETIREMENT OBLIGATIONS

The following table presents activity for our estimated AROs:

	Year Ended December 31, 2022	2021
	(In thousands)	
ARO liability, beginning of period	$ 25,688	$ 23,356
Accretion of discount	1,798	1,892
Liability incurred	22	7
Liability settled	(1,085)	(1,140)
Liability sold	(7,284)	(1,935)
Revision of estimates [(1)]	4,301	3,507
ARO liability, end of period	23,440	25,688
Less: current portion	2,858	2,537
Long-term ARO liability	$ 20,582	$ 23,151

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, 2022	2021
	(In thousands)	
Workers' compensation liability, beginning of period	$ 7,925	$ 10,164
Claims and valuation adjustments	838	(1,834)
Payments	(419)	(405)
Workers' compensation liability, end of period	8,344	7,925
Less: current portion	1,070	1,221
Long-term workers' compensation liability	$ 7,274	$ 6,704

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, 2022 and 2021 are $4.8 million and $4.0 million, respectively, and are included in other assets on our consolidated balance sheets.

NOTE 12 – INCOME TAXES

As a result of the Plan in 2020, the Company experienced an ownership change under Sec. 382 of the Internal Revenue Code (IRC). Under IRC Sec. 382, the Company’s tax attributes, most notably its net operating loss carryovers, are potentially subject to various limitations going forward. The Company believes it has satisfied the requirements of Sec. 382(l)(5) whereby our tax attributes are generally not subject to limitations under Sec. 382(a) and have reflected that result in our financial statements accordingly. While cancellation of debt income (CODI) is generally considered taxable income under IRC Sec. 108, it provides an exception to that rule for CODI realized under a Title 11 case of the United States Code. In exchange for this exception, the taxpayer must reduce certain tax attributes including its net operating loss carryovers, credit carryovers, and tax basis in its assets in the amount of the CODI not recognized under the IRC Sec. 108 exception. The amount of CODI not recognized as a result of the IRC Sec. 108 exception was $506.3 million. As a result, our net operating loss carryovers were reduced by $456.3 million and the tax basis of our assets were reduced by $50.0 million.

The following table presents a reconciliation between income tax expense computed by applying the federal statutory rate to income before income taxes and our effective income tax expense during the periods indicated:

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(In thousands)	
Income tax expense computed by applying the statutory rate	$ 31,228	$ 12,772
State income tax expense, net of federal benefit	5,538	2,129
Restricted stock shortfall	(723)	—
Non-controlling interest in Superior	(1,428)	(3,046)
Valuation allowance	(43,008)	(16,612)
Warrant liability revaluation	7,184	4,640
Statutory depletion and other	1,542	290
Income tax expense	$ 333	$ 173

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

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(In thousands)	
Current taxes:		
Federal	$ —	$ —
State	333	173
	333	173
Deferred taxes:		
Federal	—	—
State	—	—
	—	—
Total provision for income taxes	$ 333	$ 173

The following table presents the components of net deferred tax assets and liabilities:

	As of December 31,	
	2022	2021
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 15,662	$ 23,819
Net operating loss carryforward	81,199	94,441
Depreciation, depletion, amortization, and impairment	43,172	68,001
Alternative minimum tax and research and development tax credit carryforward	1,738	1,738
	141,771	187,999
Deferred tax liability:		
Investment in Superior	(406)	(3,626)
Net deferred tax asset	141,365	184,373
Valuation allowance	(141,365)	(184,373)
Non-current—deferred tax liability	$ —	$ —

We concluded that it is more likely than not that the net deferred tax asset will not be realized and have recorded a full valuation allowance as of December 31, 2022 and 2021, reducing the net deferred tax asset to zero. The Company's pre-tax earnings since the Emergence Date remained in a three-year net cumulative loss position as of December 31, 2022, however, we will continue to evaluate whether the valuation allowance is appropriate in future reporting periods. Future events or new evidence which may lead the Company to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings since the Emergence Date, sustained strength or improvements in commodity prices, sustained or improved rig utilization or rates, a material and sizable asset acquisition or disposition, and taxable events that could result from one or more future potential transactions. The valuation allowance does not prohibit the Company from utilizing the tax attributes if the Company recognizes taxable income. As long as the Company has deferred tax assets available and continues to conclude that the valuation allowance against its net deferred tax assets is necessary, the Company will not have significant deferred income tax expense or benefit.

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 2019 or state income tax examinations by state taxing authorities for years before 2018. As of December 31, 2022, the Company has an expected federal net operating loss carryforward of $331.4 million of which $136.4 million is subject to expiration between 2036 and 2037. As of December 31, 2022, our tax basis in UPC's properties was approximately $333.8 million.

NOTE 13 – EMPLOYEE BENEFIT PLANS

Separation Benefit Plans. As of the Emergence Date, the Board adopted (i) the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (Amended Separation Benefit Plan), (ii) the Amended and Restated Special Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (Amended Special Separation Benefit Plan) and (iii) the Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (New Separation Benefit Plan). In accordance with the Plan, the Amended Separation Benefit Plan and the Amended Special Separation Benefit Plan allowed former employees or retained employees with vested severance benefits under either plan to receive certain cash payments in full satisfaction for their allowed separation claim under the Chapter 11 Cases.

Also in accordance with the Plan, the New Separation Benefit Plan was a comprehensive severance plan for retained employees, including retained employees whose severance did not already vest under the Amended Separation Benefit Plan or the Amended Special Separation Benefit Plan. The New Separation Benefit Plan provided eligible employees that are involuntarily separated with two weeks of severance pay per year of service, with a minimum of four weeks and a maximum of 13 weeks. These benefits also vested for voluntary separation after 20 years of service provided to the Company.

On November 1, 2021, the New Separation Benefit Plan was amended (Amended New Separation Benefit Plan) with consideration to the Divestiture Program to redefine which employees are entitled to the two weeks of severance pay per year of service with a minimum of four weeks and a maximum of 13 weeks as well as introduce new employee groups entitled to involuntary separation benefits equal to four months of base salary, six months of base salary, or 12 months of base salary if eligible upon involuntary separation. The Amended New Separation Benefit Plan maintains a 13 week severance benefit for voluntary separation which vests after 20 years of service provided to the Company.

We recognized expense for benefits associated with anticipated payments from these separation plans of $3.9 million and $3.4 million during the years ended December 31, 2022 and 2021, respectively.

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 or common stock. The 2020 and 2021 plan year matching contributions were made in cash. Total 401(k) employer matching expense was $1.4 million and $1.6 million during the years ended December 31, 2022 and 2021, respectively.

NOTE 14 – TRANSACTIONS WITH RELATED PARTIES

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. 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 and Cactus Drilling Company.

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

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Payments made to:		
Kaiser Francis Oil Company	$ 5,656	$ 5,748
Cactus Drilling Company	$ —	$ 772
Payments received from:		
Kaiser Francis Oil Company	$ 12,869	$ 6,237

NOTE 15 – STOCK-BASED COMPENSATION

Unit Corporation Long Term Incentive Plan. On the Effective 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.

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

	Year Ended December 31, 2022	2021
	(In thousands)	
Recognized stock compensation expense	$ 6,718	$ 826
Capitalized stock compensation cost for our oil and natural gas properties	$ —	$ —
Tax benefit on stock-based compensation	$ 1,646	$ 202

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

	Year Ended December 31, 2022		2021	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested RSUs, beginning of period	315,529	$ 26.71	—	$ —
Granted [1]	7,850	30.50	315,529	26.71
Vested	(151,341)	26.33	—	—
Forfeited	(1,725)	34.00	—	—
Nonvested RSUs, end of period [2]	170,313	$ 27.15	315,529	$ 26.71

1. RSUs granted in January 2022 had an aggregate grant date fair value of $0.2 million and vest equally each month for thirty months. RSUs granted in April 2021 had an aggregate grant date fair value of $1.4 million and vest 25% on each of the following dates: May 27, 2022, September 3, 2022, September 3, 2023, and September 3, 2024. RSUs granted in October 2021 had an aggregate grant date fair value of $7.0 million and one-third vest on each of the following dates: November 21, 2022, October 1, 2023, and October 1, 2024.
2. The aggregate compensation cost related to nonvested RSUs not yet recognized as of December 31, 2022 was $4.2 million with a weighted average remaining service period of 1.2 years.

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

	Year Ended December 31, 2022		2021	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding stock options, beginning of period	361,418	$ 45.00	—	$ —
Granted [1]	13,416	45.00	361,418	45.00
Exercised	(55,668)	45.00	—	—
Forfeited or expired	—	—	—	—
Outstanding stock options, end of period [2] [4]	319,166	$ 45.00	361,418	$ 45.00
Exercisable stock options, end of period [3] [4]	108,755	$ 45.00	—	$ —

1. Stock options granted in January 2022 had an aggregate grant date fair value of $0.1 million and 100% vest on the first anniversary of the grant date. Stock options granted in October 2021 had an aggregate grant date fair value of $4.1 million and and one-third vest on each of the following dates: October 1, 2022, October 1, 2023, and October 1, 2024.
2. Stock options outstanding as of December 31, 2022 had a weighted average remaining contractual term of 3.7 years and an aggregate intrinsic value of $4.1 million. The aggregate compensation cost related to outstanding options not yet recognized as of December 31, 2022 was $2.7 million with a weighted average remaining service period of 1.2 years.
3. Stock options exercisable as of December 31, 2022 had a weighted average remaining contractual term of 3.8 years and an aggregate intrinsic value of $1.4 million.
4. On January 6, 2023, in accordance with the provisions allowed under the LTIP, the Compensation Committee adjusted the exercise price of all outstanding stock options to $35.00 per share effective January 31, 2023 to account for the special dividend paid on that date.

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 Exit credit agreement. As of December 31, 2022, 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.
- *Collars.* A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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, 2022.

The following non-designated hedges were outstanding as of December 31, 2022:

Remaining Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'23 - Feb'23	Natural gas - swap	27,627 MMBtu/day	$9.14	IF - NYMEX (HH)
Jan'23 - Dec'23	Natural gas - swap	22,000 MMBtu/day	$2.46	IF - NYMEX (HH)
Jan'23 - Mar'23	Natural gas - basis swap	25,000 MMBtu/day	$(0.17)	NGLP TEXOK
Jan'23 - Feb'23	Crude oil - swap	1,339 Bbl/day	$95.40	WTI - NYMEX
Jan'23 - Dec'23	Crude oil - swap	1,300 Bbl/day	$43.60	WTI - NYMEX

Warrants

Prior to the determination of the initial exercise price, we recognized the fair value of the warrants as a derivative liability on our consolidated balance sheets with changes in the liability reported as loss on change in fair value of warrants in our consolidated statements of operations. On April 7, 2022, the Company delivered notice of the initial $63.74 exercise price resulting in the warrants meeting the definition of an equity instrument. Accordingly, we recognized the change in the fair value of the warrant liability in our unaudited condensed consolidated statements of operations and reclassified the $49.1 million warrant liability to capital in excess of par value on the unaudited condensed consolidated balance sheets as of April 7, 2022. The warrants will continue to be reported as capital in excess of par value and are no longer subject to future fair value adjustments.

The following tables present the recognized liabilities on our consolidated balance sheets as of the dates identified:

	Balance Sheet Classification	Balances as of December 31, 2022 Presented Gross	Effects of Netting	Presented Net
			(In thousands)	
Assets:				
Current Commodity Derivatives	Current derivative assets	$ 8,547	$ (8,547)	$ —
Long-term Commodity Derivatives	Non-current derivative assets	—	—	—
Total derivative assets		$ 8,547	$ (8,547)	$ —
Liabilities:				
Current Commodity Derivatives	Current derivative liabilities	$ 32,113	$ (8,547)	$ 23,566
Long-term Commodity Derivatives	Non-current derivative liabilities	—	—	—
Warrant Liability	Warrant liability	—	—	—
Total derivative liabilities		$ 32,113	$ (8,547)	$ 23,566

	Balance Sheet Classification	Balances as of December 31, 2021 Presented Gross	Effects of Netting	Presented Net
			(In thousands)	
Liabilities:				
Current Commodity Derivatives	Current derivative liabilities	$ 40,876	$ —	$ 40,876
Long-term Commodity Derivatives	Non-current derivative liabilities	17,855	—	17,855
Warrant Liability	Warrant liability	19,822	—	19,822
Total derivative liabilities		$ 78,553	$ —	$ 78,553

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

	Year Ended December 31, 2022	2021
	(In thousands)	
Loss on derivatives	$ (63,610)	$ (97,615)
Cash settlements paid on commodity derivatives	(98,775)	(44,591)
Loss on derivatives less cash settlements paid on commodity derivatives	$ 35,165	$ (53,024)
Loss on change in fair value of warrants	$ (29,323)	$ (18,937)

NOTE 17 – FAIR VALUE MEASUREMENTS

The inputs available determine the valuation technique that we use to measure the fair value of the 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 tables present our recurring fair value measurements as of the identified dates:

	Balances as of December 31, 2022			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial liabilities:				
Commodity derivative liabilities	$ —	$ 23,566	$ —	$ 23,566
Warrant liability	—	—	—	—
	$ —	$ 23,566	$ —	$ 23,566

	Balances as of December 31, 2021			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial liabilities:				
Commodity derivative liabilities	—	58,731	—	58,731
Warrant liability	—	—	19,822	19,822
	$ —	$ 58,731	$ 19,822	$ 78,553

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 assets (liabilities).

Commodity Derivatives. We measure the fair values of our crude oil and natural gas swaps and collars 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, 2022.
Warrant Liability. We used the Black-Scholes option pricing model to measure the fair value of the warrants. Key inputs for the Black-Scholes model 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.

The following table presents the activity of our recurring Level 3 fair value measurements during the periods presented:

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Beginning of period	$ 19,822	$ 885
Loss on change in warrant liability	29,323	18,937
Reclassification of warrant liability to capital in excess of par value	(49,145)	—
End of period	$ —	$ 19,822

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.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and considering the risk of our non-performance, long-term debt under our credit agreements at December 31, 2022 would approximate its fair value. This debt is classified as Level 2.

Fair Value of Non-Financial Instruments

ARO. The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property and equipment. Significant Level 3 inputs used in the calculation of AROs include plugging costs and remaining reserve lives. 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 options and SARs while the value of our restricted stock 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 and expected term are generally unobservable and requires 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 non-cash impairment charges as discussed further in Note 3 – Impairments. 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.

In September 2021, we entered into an operating lease agreement for our headquarters office space which generated right of use assets and liabilities at lease inception of $8.4 million.

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, 2022:

	Amount (In thousands)
Ending December 31,	
2023	$ 1,999
2024	2,004
2025	2,044
2026	1,472
2027	—
2028 and beyond	—
Total future payments	7,519
Less: Interest	879
Present value of future minimum operating lease payments	6,640
Less: Current portion	1,605
Total long-term operating lease payments	$ 5,035
Weighted average remaining lease term (years)	3.7
Weighted average discount rate [1]	6.7 %

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.

Finance Leases. During 2014, Superior entered into finance lease agreements for 20 compressors with initial terms of seven years and an option to purchase the assets at 10% of their then fair market value at the end of the term. These finance leases were discounted using annual rates of 4.0% and the underlying assets are included in gas gathering and processing equipment. Superior purchased the leased assets for $3.0 million in May 2021.

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

	Balance Sheet Classification	December 31, 2022	December 31, 2021
		(In thousands)	
Assets			
Operating lease right of use assets	Right of use assets	$ 6,551	$ 12,445
Total lease right of use assets		$ 6,551	$ 12,445
Liabilities			
Current liabilities:			
Operating lease liabilities	Current operating lease liabilities	$ 1,605	$ 3,791
Non-current liabilities:			
Operating lease liabilities	Operating lease liabilities	5,035	8,677
Total lease liabilities		$ 6,640	$ 12,468

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

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Components of total lease cost:		
Short-term lease cost [(1)]	$ 10,650	$ 12,898
Operating lease cost	3,278	4,546
Amortization of finance leased assets	—	1,248
Interest on finance lease liabilities	—	33
Total lease cost	$ 13,928	$ 18,725

1. Short-term lease cost includes amounts capitalized related to our oil and natural gas segment of $1.8 million and $1.5 million for the year ended December 31, 2022 and 2021, respectively.

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

	Year Ended December 31,	
	2022	2021
	(In thousands)	
Cash payments made on operating leases	$ 3,210	$ 4,605
Cash payments made on finance leases	$ —	$ 3,216
Lease liabilities recognized in exchange for new operating lease right of use assets	$ 909	$ 11,155

NOTE 19 – SUPERIOR INVESTMENT

On April 3, 2018, we sold 50% of the ownership interest in Superior to SP Investor Holdings, LLC (SP Investor), a holding company jointly owned by OPTrust, and funds managed and/or advised by Partners Group, a global private markets investment manager. Superior is governed and managed under the Amended and Restated Limited Liability Company Agreement (Agreement) and Amended and Restated Master Services and Operating Agreement (MSA). The MSA was between our wholly-owned subsidiary, SPC Midstream Operating, L.L.C. (the Operator), and Superior. As the Operator, we provided services, such as operations and maintenance support, accounting, legal, and human resources to Superior for a monthly service fee of $0.3 million. Superior's creditors have no recourse to our general credit. Unit is not a party to and does not guarantee Superior's credit agreement. The obligations under Superior's credit agreement are secured by, among other things, mortgage liens on certain of Superior’s processing plants and gathering systems.

Distributions. The Agreement specifies how future distributions are to be allocated among Unit Corporation and SP Investor (the Members). Distributions from Available Cash (as defined in the Agreement) were generally split evenly between the Members prior to December 31, 2021, when the three-year period for Unit's commitment to spend $150.0 million (Drilling Commitment Amount) to drill wells in the Granite Wash/Buffalo Wallow area ended. The total amount spent by Unit towards the Drilling Commitment Amount was $24.6 million. Accordingly, SP Investor will receive 100% of Available Cash distributions related to periods subsequent to December 31, 2021 until the $72.7 million Drilling Commitment Adjustment Amount (as defined in the Agreement) is satisfied.

The following table presents the distributions paid by Superior to each of the members during the years ended December 31, 2022 and 2021:

Date	Recipient	Amount
2022		
October 31, 2022	SP Investor	$16.2 million
July 29, 2022	SP Investor	$13.9 million
April 29, 2022	SP Investor	$10.5 million
January 31, 2022	Unit Corporation	$9.5 million
January 31, 2022	SP Investor	$9.5 million
2021		
October 29, 2021	Unit Corporation	$7.0 million
October 29, 2021	SP Investor	$7.0 million
July 30, 2021	Unit Corporation	$3.8 million
July 30, 2021	SP Investor	$3.8 million
April 30, 2021	Unit Corporation	$12.3 million
April 30, 2021	SP Investor	$12.3 million

Superior also paid distributions to SP Investor of $11.1 million in January 2023 which reduced the remaining Drilling Commitment Adjustment Amount to $20.9 million.

Sale Event. After April 1, 2023, either Member may initiate a sale process of Superior to a third-party or a liquidation of Superior's assets (Sale Event). In a Sale Event, the Agreement generally requires cumulative distributions to SP Investor in excess of its original $300.0 million investment sufficient to provide SP Investor a 7% internal rate of return on its capital contributions to Superior before any liquidation distribution is made to Unit. As of December 31, 2022, liquidation distributions paid first to SP Investor of $335.2 million would be required for SP Investor to reach its 7% Liquidation IRR Hurdle at which point Unit would then be entitled to receive up to $335.2 million of the remaining liquidation distributions to satisfy Unit's 7% Liquidation IRR Hurdle with any remaining liquidation distributions paid as outlined within the Agreement.

On February 21, 2023, we entered into a letter agreement (the "Letter Agreement") with SP Investor under which the Company has agreed to sell all of its 50% ownership interest in Superior for $20.0 million. The Letter Agreement provides that SP Investor will pay Unit $12.0 million at closing and $8.0 million in deferred proceeds to be paid no later than 12 months from closing, subject to Unit's satisfaction of certain ongoing covenant obligations and other customary conditions.

Consolidation. From April 3, 2018 to March 1, 2022, we treated Superior as a variable interest entity (VIE) because the equity holders as a group (Unit Corporation and SP Investor) lacked the power to control without the Operator. The Agreement and MSA gave us the power to direct the activities that most significantly affect Superior's operating performance through common control of the Operator. Accordingly, Unit was considered the primary beneficiary and consolidated the financial position, operating results, and cash flows of Superior.

Effective March 1, 2022, the employees of the Operator were transferred to Superior and the MSA was amended and restated to remove the operating services the Operator was providing to Superior. There was no change to the monthly service fee for shared services. The power to direct the activities that most significantly affect Superior's operating performance is now shared by the equity holders (Unit Corporation and SP Investor) rather than held by the Operator. Superior no longer qualifies as a VIE subsequent to these amendments and we no longer consolidate the financial position, operating results, and cash flows of Superior as of, and subsequent to, March 1, 2022.

We subsequently account for our investment in Superior as an equity method investment using the hypothetical liquidation book value (HLBV) method, which is a balance sheet approach that calculates the change in the hypothetical amount Unit and SP Investor would be entitled to receive if Superior were liquidated at book value at the end of each period, adjusted for any contributions made and distributions received during the period. We recognized no equity earnings from our investment in Superior during the year ended December 31, 2022.

Estimated Fair Value of Equity Method Investment in Superior. As of the Emergence Date, in conjunction with fresh start accounting under ASC Topic 852, *Reorganizations*, the estimated fair value of the net equity attributable to Unit's ownership interest in Superior was $14.8 million. Since then, Unit has received cumulative distributions from Superior of $32.6 million, which were recognized as net income attributable to Unit under the HLBV method. As of March 1, 2022, upon deconsolidation of Superior, the fair value of our retained equity method investment in Superior was estimated at $1.7 million. To estimate this fair value, we simulated paths for Superior's total equity value through the potential sales process initiation date using a Geometric Brownian Motion. The expected value (i.e., average of all simulations) of each security class was then discounted to present value using the relevant risk-free rate. The simulations reflect forecasted future cash distributions as impacted by the Drilling Commitment Adjustment Amount described above, as well as the future liquidation preference of each investor in a potential Sale Event also as described above. We consider this a Level 3 measurement within the fair value hierarchy as the discounted simulation models require the use of significant unobservable inputs.

We recognized a $13.1 million loss on deconsolidation during the three months ended March 31, 2022 as the difference between the $1.7 million estimated fair value of our retained equity method investment in Superior as of March 1, 2022 and Superior's net equity attributable to Unit's ownership interest prior to deconsolidation.

Superior Balance Sheet Disclosure. The amounts below reflect the Superior balance sheet accounts, without elimination of intercompany receivables from and payables to Unit, consolidated in our consolidated balance sheets as of December 31, 2021 which was the last reporting date as of which we consolidated the financial position of Superior:

	December 31, 2021
	(In thousands)
Current assets:	
Cash and cash equivalents	$ 17,246
Accounts receivable	42,628
Prepaid expenses and other	1,263
Total current assets	61,137
Property and equipment:	
Gas gathering and processing equipment	274,748
Transportation equipment	2,801
	277,549
Less accumulated depreciation, depletion, amortization, and impairment	53,792
Net property and equipment	223,757
Right of use asset	3,485
Other assets	2,226
Total assets	$ 290,605
Current liabilities:	
Accounts payable	$ 34,010
Accrued liabilities	5,292
Current operating lease liability	1,450
Current portion of other long-term liabilities	1,548
Total current liabilities	42,300
Long-term debt	19,200
Operating lease liability	2,036
Total liabilities	$ 63,536

Affiliate Activity. UPC's oil and natural gas revenues with Superior totaled $67.1 million and $48.0 million during the years ended December 31, 2022 and 2021, respectively. UPC's gas gathering and processing expenses with Superior totaled $2.7 million and $3.3 million during the years ended December 31, 2022 and 2021, respectively. Portions of this activity was eliminated for the periods during which Superior was consolidated by Unit.

NOTE 20 – 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.

We have not historically experienced significant environmental liability while being a contract driller since the greatest portion of that risk is borne by the operator. Any liabilities we have incurred have been small and were resolved while the drilling rig was on the location. Those costs were in the direct cost of drilling the well.

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.

In February 2021, UPC finalized a settlement agreement for $2.1 million related to a well drilled in Beaver County, Oklahoma during 2013. Certain operational issues arose and one of the working interest owners in the well filed a lawsuit claiming that UPC’s actions violated its duties under the joint operating agreement and caused damages to the owners in the well. The case went to trial in January 2019 and the jury issued a verdict in favor of the working interest owner, awarding $2.4 million in damages, including pre- and post-judgment interest. UPC appealed the verdict and finalized the settlement agreement while the case was pending review in the Oklahoma Court of Civil Appeals.

NOTE 21 - 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.

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

	Year Ended December 31,	
	2022	2021
Oil and Natural Gas [1]:		
CVR Energy, Inc.	10%	11%
Drilling:		
Diamondback E&P, LLC	19%	15%
Coterra Energy, Inc.	15%	*
Citizen Energy III, LLC	14%	20%
Earthstone Operating, LLC	12%	11%
EOG Resources, Inc.	11%	21%
Slawson Exploration Company, Inc.	*	12%
Mid-Stream [2]:		
ONEOK, Inc.	36%	37%
Southwest Energy, LP	15%	*
Symmetry Energy Solutions LLC	14%	*
Range Resources Corporation	*	11%
Koch Energy Services	*	10%

* Revenue accounted for less than 10% of the segment's revenues.

1) See Note 19 - Superior Investment for information on affiliate activity with Superior

2) Mid-Stream amounts shown in this table for the year ended December 31, 2022 reflect Superior activity on a consolidated basis for the two months prior to March 1, 2022.

We had a concentration of cash with one bank of $2.8 million and $36.6 million as of December 31, 2022 and 2021, respectively. We also had a concentration of cash equivalents of $134.7 million and $76.0 million in two separate money market funds comprised of U.S. Government and U.S. Treasury securities as of December 31, 2022 compared to cash equivalents of $27.0 million in one of those funds as of December 31, 2021.

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, 2022 and determined there was no material risk at that time. The fair value of the net derivative liabilities with Bank of Oklahoma, our only commodity derivative counterparty, was $23.6 million of December 31, 2022.

NOTE 22 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services within the energy industry:

- *Oil and natural gas* - the oil and natural gas segment is engaged in the acquisition, development, and production of oil, NGLs, and natural gas properties.
- *Contract drilling* - the contract drilling segment is engaged in the land contract drilling of oil and natural gas wells.
- *Mid-Stream* - the mid-stream segment buys, sells, gathers, processes, and treats natural gas and NGLs for third parties and for our own account. We presently own 50% of this subsidiary, and subsequent to the deconsolidation of Superior as of March 1, 2022 (as discussed in Note 2 - Summary Of Significant Accounting Policies and Note 19 - Superior Investment), we will continue to include our equity method investment in Superior and related earnings in our mid-stream segment.

We evaluate each consolidated segment’s performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. We have no oil and natural gas production or other operations outside the United States.

The following tables present information about the operations and assets for each of our segments:

	Year Ended December 31, 2022					
	Oil and Natural Gas	Contract Drilling	Mid-Stream [5]	Corporate and Other	Eliminations [5]	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$ 326,238	$ —	$ —	$ —	$ (10,756)	$ 315,482
Contract drilling	—	147,740	—	—	(370)	147,370
Gas gathering and processing	—	—	83,198	—	(525)	82,673
Total revenues	326,238	147,740	83,198	—	(11,651)	545,525
Expenses:						
Operating costs:						
Oil and natural gas	93,859	—	—	—	(509)	93,350
Contract drilling	—	105,608	—	—	(221)	105,387
Gas gathering and processing	—	—	73,771	—	(11,383)	62,388
Total operating costs	93,859	105,608	73,771	—	(12,113)	261,125
Depreciation, depletion, and amortization	11,780	6,416	5,614	333	—	24,143
Impairment	—	—	—	—	—	—
General and administrative	—	—	—	24,033	611	24,644
(Gain) loss on disposition of assets	—	(8,404)	—	37	—	(8,367)
Total operating expenses	105,639	103,620	79,385	24,403	(11,502)	301,545
Income (loss) from operations	220,599	44,120	3,813	(24,403)	(149)	243,980
Other income (expense):						
Interest income	—	—	—	2,642	—	2,642
Interest expense	—	—	(179)	(268)	—	(447)
Loss on derivatives	—	—	—	(63,610)	—	(63,610)
Loss on change in fair value of warrants	—	—	—	(29,323)	—	(29,323)
Loss on deconsolidation of Superior	—	—	—	(13,141)	—	(13,141)
Reorganization items, net	—	—	—	(127)	—	(127)
Other	1,520	53	17	1,310	—	2,900
Total other income (expense)	$ 1,520	$ 53	$ (162)	$ (102,517)	$ —	$ (101,106)
Income (loss) before income taxes	$ 222,119	$ 44,173	$ 3,651	$ (126,920)	$ (149)	$ 142,874
Identifiable assets:						
Oil and natural gas [2]	$ 145,711	$ —	$ —	$ —	$ (148)	$ 145,563
Contract drilling	—	94,559	—	—	—	94,559
Total identifiable assets [3]	145,711	94,559	—	—	(148)	240,122
Other corporate assets [4]	—	—	1,658	227,475	—	229,133
Total assets	$ 145,711	$ 94,559	$ 1,658	$ 227,475	$ (148)	$ 469,255
Capital expenditures:	$ 21,037	$ 11,134	$ 1,167	$ 406	$ (148)	$ 33,596

1. The revenues for oil and natural gas occur at a point in time. The revenues for contract drilling and gas gathering and processing occur over time.
2. Oil and natural gas assets include oil and natural gas properties, saltwater disposal systems, and other non-full cost pool assets.
3. Identifiable assets are those used in Unit's operations in each industry segment.
4. Other corporate assets are primarily cash and cash equivalents, transportation and other equipment, and our Superior equity method investment.
5. Includes Superior activity for the two months prior to the March 1, 2022 deconsolidation, as discussed in Note 2 - Summary Of Significant Accounting Policies and Note 19 - Superior Investment. Superior's standalone total revenues and total operating costs for the year ended December 31, 2022 were $528.8 million and $452.1 million, respectively.

	Year Ended December 31, 2021					
	Oil and Natural Gas	Contract Drilling	Mid-Stream	Corporate and Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$ 272,231	$ —	$ —	$ —	$ (47,999)	$ 224,232
Contract drilling	—	76,107	—	—	—	76,107
Gas gathering and processing	—	—	341,674	—	(3,297)	338,377
Total revenues	272,231	76,107	341,674	—	(51,296)	638,716
Expenses:						
Operating costs:						
Oil and natural gas	83,221	—	—	—	(3,297)	79,924
Contract drilling	—	60,973	—	—	—	60,973
Gas gathering and processing	—	—	286,199	—	(51,515)	234,684
Total operating costs	83,221	60,973	286,199	—	(54,812)	375,581
Depreciation, depletion, and amortization	24,612	6,308	32,566	840	—	64,326
Impairment	—	—	10,673	—	—	10,673
General and administrative	—	—	—	21,399	3,516	24,915
(Gain) loss on disposition of assets	171	(10,143)	49	(954)	—	(10,877)
Total operating expenses	108,004	57,138	329,487	21,285	(51,296)	464,618
Income (loss) from operations	164,227	18,969	12,187	(21,285)	—	174,098
Other income (expense):						
Interest income	—	—	—	2	—	2
Interest expense	—	—	(924)	(3,342)	—	(4,266)
Loss on derivatives	—	—	—	(97,615)	—	(97,615)
Loss on change in fair value of warrants	—	—	—	(18,937)	—	(18,937)
Reorganization items, net		—	—	(4,294)	—	(4,294)
Other	187	57	(844)	1	—	(599)
Total other income (expense)	$ 187	$ 57	$ (1,768)	$ (124,185)	$ —	$ (125,709)
Income (loss) before income taxes	$ 164,414	$ 19,026	$ 10,419	$ (145,470)	$ —	$ 48,389
Identifiable assets:						
Oil and natural gas [2]	$ 203,796	$ —	$ —	$ —	$ (4,917)	$ 198,879
Contract drilling	—	78,554	—	—	(78)	78,476
Gas gathering and processing	—	—	290,605	—	(269)	290,336
Total identifiable assets [3]	203,796	78,554	290,605	—	(5,264)	567,691
Other corporate assets [4]	—	—	—	66,227	(4,441)	61,786
Total assets	$ 203,796	$ 78,554	$ 290,605	$ 66,227	$ (9,705)	$ 629,477
Capital expenditures:	$ 17,752	$ 2,877	$ 24,316	$ 340	$ —	$ 45,285

1. The revenues for oil and natural gas occur at a point in time. The revenues for contract drilling and gas gathering and processing occur over time.
2. Oil and natural gas assets include oil and natural gas properties, saltwater disposal systems, and other non-full cost pool assets.
3. Identifiable assets are those used in Unit's operations in each industry segment.
4. Other corporate assets are principally cash and cash equivalents, short-term investments, transportation equipment, furniture, and equipment.

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, 2022	As of December 31, 2021
	(In thousands)	
Proved properties [(1)]	$ 177,134	$ 225,014
Unproved properties (wells in progress)	6,953	422
	184,087	225,436
Accumulated depreciation, depletion, amortization, and impairment	(76,077)	(64,966)
Net capitalized costs	$ 108,010	$ 160,470

1. Presented gross of any inter-segment eliminations which reduce the consolidated capitalized costs. See Note 22 - Industry Segment Information for detail on inter-segment eliminations.

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, 2022	Year Ended December 31, 2021
	(In thousands)	
Unproved properties acquired	$ 3,963	$ 522
Proved properties acquired	—	—
Exploration	—	—
Development	16,070	16,279
Asset retirement obligation	3,018	478
Total costs incurred	$ 23,051	$ 17,279

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, 2022	Year Ended December 31, 2021
	(In thousands)	
Revenues from producing activities	$ 314,554	$ 223,681
Production costs	(73,736)	(62,443)
Depreciation, depletion, amortization, and impairment	(11,192)	(24,261)
	229,626	136,977
Income tax (expense) benefit	45	168
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 229,671	$ 137,145

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)
2021				
Proved developed and undeveloped reserves:				
Beginning of year	8,267	15,208	144,391	47,541
Revision of previous estimates [1]	2,651	8,723	103,866	28,685
Extensions and discoveries	218	93	961	471
Infill reserves in existing proved fields	713	293	2,158	1,366
Purchases of minerals in place	—	—	—	1
Production	(1,615)	(2,624)	(29,012)	(9,074)
Sales [3]	(1,215)	(169)	(1,725)	(1,672)
Net proved reserves at December 31, 2021	9,019	21,525	220,640	67,318
Proved developed reserves, December 31, 2021	9,019	21,525	220,640	67,318
Proved undeveloped reserves, December 31, 2021	—	—	—	—
2022				
Proved developed and undeveloped reserves:				
Beginning of year	9,019	21,525	220,640	67,318
Revision of previous estimates [2]	73	1,884	29,295	6,840
Extensions and discoveries	189	133	2,551	747
Infill reserves in existing proved fields	54	18	1,773	368
Purchases of minerals in place	—	—	—	—
Production	(1,281)	(2,148)	(24,211)	(7,464)
Sales [3]	(373)	(1,280)	(17,639)	(4,593)
Net proved reserves at December 31, 2022	7,681	20,132	212,409	63,215
Proved developed reserves, December 31, 2022	7,681	20,132	212,409	63,215
Proved undeveloped reserves, December 31, 2022	—	—	—	—

1. Revisions of previous estimates increased primarily due to changes in the unescalated 12-month average product prices which increased approximately 68% for oil, 136% for NGLs, and 82% for natural gas compared to the December 31, 2020 pricing.
2. Revisions of previous estimates increased primarily due to changes in the unescalated 12-month average product prices which increased approximately 41% for oil and 77% for natural gas compared to the December 31, 2021 pricing.
3. See Note 5 - Acquisitions And Divestitures for discussion of the assets divested during the years ended December 31, 2022 and 2021, respectively.

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 Tax Act statutory tax rates.

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

	2022	2021
	(In thousands)	
Future cash inflows	$ 2,918,116	$ 1,977,529
Future production costs	(1,142,754)	(835,430)
Future development costs	(1,724)	—
Future income tax expenses	(355,350)	(185,395)
Future net cash flows	1,418,288	956,704
10% annual discount for estimated timing of cash flows	(633,263)	(385,560)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 785,025	$ 571,144

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

	2022	2021
	(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (240,818)	$ (161,238)
Net changes in prices and production costs	377,923	334,291
Revisions in quantity estimates and changes in production timing	109,772	320,774
Extensions, discoveries, and improved recovery, less related costs	34,121	45,019
Changes in estimated future development costs	(1,615)	—
Previously estimated cost incurred during the period	—	—
Purchases of minerals in place	—	—
Sales of minerals in place	(28,704)	(4,161)
Accretion of discount	65,826	19,306
Net change in income taxes	(84,421)	(87,078)
Changes in timing and other	(18,203)	(88,791)
Net change	213,881	378,123
Beginning of year	571,144	193,021
End of year	$ 785,025	$ 571,144

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, 2022 future cash flows were computed by applying the 12-month 2022 average unescalated prices of $93.67 per barrel of oil and $6.36 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.

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

None.

Item 9A. Controls and Procedures

Our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) (Disclosure Controls) or our internal control over financial reporting (as defined in Rules 13a - 15(f) and 15d - 15(f) of the Exchange Act) will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of a simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part on certain assumptions about the likelihood of future events, and there is no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to an error or fraud may occur and not be detected. We monitor our Disclosure Controls and internal control over financial reporting and make modifications as necessary; our intent in this regard is that the Disclosure Controls and internal control over financial reporting will be modified as systems change, and conditions warrant.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2022.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Our management, including our CEO and CFO, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2022.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting during the quarter ended December 31, 2022, that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Information About Our Executive Officers

The table below and accompanying text sets forth certain information as of March 14, 2023, concerning each of our executive officers and certain officers of our subsidiaries. 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
Philip B. Smith	71	Director since September 3, 2020, Chairman since September 8, 2020, President and Chief Executive Officer since October 22, 2020
Andrew E. Harding	45	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	58	Chief Financial Officer and Controller since June 23, 2021; Chief Accounting Officer since December 31, 2020; Interim Chief Financial Officer from October 22, 2020 to June 23, 2021
Christopher K. Menefee	45	President, Unit Drilling Company since November 9, 2020

Mr. Smith was named to the Board of Directors on September 3, 2020 and became Chairman on September 8, 2020. In October 2020, Unit's Board of Directors named him to the positions of President and Chief Executive Officer. 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 1997. He received a Bachelor of Science in Mechanical Engineering from Oklahoma State University and a Master of Business Administration from the University of Tulsa. On February 23, 2023, Philip B. Smith notified the Company’s Board of Directors of his decision to step down as President and Chief Executive Officer of the Company effective March 31, 2023. His decision to step down was due to his desire to spend more time working on his nonprofit projects and other endeavors. Mr. Smith will continue to serve as Chairman of the Board of Directors.

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. In December 2020, he also become Chief Accounting Officer ("CAO"), and in June 2021 he became Chief Financial Officer, CAO and Controller. 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. Menefee was appointed President of Unit Drilling Company in November 2020. He most recently served as Senior Vice President, Business Development at Independence Contract Drilling, Inc., an onshore oil and gas contract drilling services company, from May 2012 to April 2020. Before that, he spent over 15 years at Rowan Companies, Inc. where he held many operational and management roles, including the Director of Marketing from 2006 to 2012. Mr. Menefee graduated from The University of Mississippi in Oxford with a Bachelor of Arts in Psychology. He holds a graduate certificate in corporate finance from the Cox School of Business at Southern Methodist University.

Information About Our Directors

The table below and accompanying text sets forth certain information as of March 14, 2023, concerning each member of our Board of Directors (the "Board"). There is currently a vacancy in Group 1.

Name	Age	Director		Committees of the Board	Term Expires	Primary Occupation
		Since	Group			
Robert R. Anderson	65	2020	II		2024	Executive, GBK Corporation, Tulsa, Oklahoma
Alan J. Carr	52	2020	II	Compensation (Chair) Strategic Transactions	2024	Chief Executive Officer, Drivetrain, LLC, New York City, New York
Phil Frohlich	68	2020	II	Audit	2024	Managing Partner, Prescott Capital Management, Tulsa, Oklahoma
Steven B. Hildebrand	68	2008	I	Audit (Chair) Strategic Transactions	2023	Investments, Tulsa, Oklahoma
Philip B. Smith	71	2020	II		2024	President, Chief Executive Officer and Chairman of the Board, Unit Corporation, Tulsa, Oklahoma
Andrei Verona	44	2020	I	Strategic Transactions (Chair) Audit, Compensation	2023	Spectrum Fund Portfolio Manager at Saye Capital Management, headquartered in Redondo Beach, California

Mr. Anderson is and has been since 2010 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 B.S. 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 is and has been since September 2013 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. 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 companies: Sears Holdings Corporation (since 2018), NewLake Capital Partners (since 2019), and Enjoy Technology, Inc. (since 2022). 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: Atlas Iron Limited; TEAC Corporation; Tidewater Inc.; Midstates Petroleum Company, Inc.; Verso Corporation; McDermott International, Inc.; 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 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. To fill the vacancy created by Mr. Smith's resignation, on February 28, 2023, the Board of Directors appointed Phil Frohlich as interim Chief Executive Officer, effective April 1, 2023, until a successor is named. Attributes, experience, and qualifications for board and committee service: executive and entrepreneurial experience; accounting, investment, business and legal expertise.

Mr. Hildebrand has been engaged in personal investments since March 2008. He retired in 2008 from Dollar Thrifty Automotive Group, Inc. (NYSE: DTG), a car rental business, where he had served as Executive Vice President and Chief Financial Officer since 1997. Prior to that, Mr. Hildebrand served as Executive Vice President and Chief Financial Officer of Thrifty Rent-A-Car System, Inc., a subsidiary of Dollar Thrifty. Mr. Hildebrand joined Thrifty Rent-A-Car System, Inc. in 1987 as Vice President and Treasurer and became Chief Financial Officer in 1989. Mr. Hildebrand was with Franklin Supply Company, an oilfield supply business, from 1980 to 1987 where he held several positions including Controller and Vice President of Finance. From 1976 to 1980, Mr. Hildebrand was with the accounting firm Coopers & Lybrand, most recently as Audit Supervisor. Mr. Hildebrand earned a B.S.B.A. degree in accounting from Oklahoma State University, and he is a certified public accountant. Attributes, experience, and qualifications for board and committee service: experience and expertise in accounting and finance, including many years of experience as a CPA; qualifications as an audit committee financial expert; executive leadership experience at a public company, including experience with strategic planning, SEC reporting, Sarbanes - Oxley compliance, investor relations, enterprise risk management, executive compensation, corporate compliance, internal audit, bank facilities, private placement debt transactions and working with ratings agencies.

Mr. Smith's biographical information is listed in the section above setting forth information about our officers. Attributes, experience, and qualifications for board and committee service: executive leadership experience and industry familiarity; entrepreneurial and business experience; engineering background.

Mr. Verona is and since 2013 has been a Portfolio Manager at Saye Capital Management, an opportunistic credit hedge fund headquartered in Redondo Beach, California. He manages 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 is the Audit 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.

Disclosure of Officer or Director Involvement in Bankruptcy-related Matters

Director Steven B. Hildebrand was a Director at the time of the filing of our Chapter 11 Cases.

Director Phil Frohlich has also been an officer or director of a company filing bankruptcy in the last ten years.

Director Alan J. Carr is a restructuring professional and during the last ten years has been on the board of numerous companies during or after their filing for bankruptcy.

Corporate Governance and Board Matters

General Governance Matters

Our Code of Business Conduct and Ethics is available at https://unitcorp.com/investor-relations/#governance and a copy may also be obtained, without charge, on request, from our corporate secretary. We have posted and will continue to post any amendments or waivers to our Code of Business Conduct and Ethics that are required to be disclosed by the rules of the SEC on our website.

Each year, our directors and executive officers are asked to complete a director and officer questionnaire which requires disclosure of any transactions with us in which the director or executive officer, or any member of his or her immediate family, have a direct or indirect material interest. Our CEO and general counsel are charged with resolving any conflict of interests not otherwise resolved under one of our other policies.

We have three committees of the Board of Directors: the audit committee, the compensation committee, and the strategic transactions committee. Charters for each committee are available on the governance page of our website, linked above.

Audit Committee Financial Experts

The Board of Directors has designated Messrs. Hildebrand, Frohlich, and Verona as Audit Committee Financial Experts as defined by SEC rules.

Material Changes to Procedures for Nominating Directors

There have been no material changes to our director nominating procedures since they were last published.

Item 11. Executive Compensation

Directors' 2022 Compensation

Our Board of Directors' compensation was determined by a group of our bondholders during our restructuring process in 2020 and remains unchanged for 2023. That group looked at director compensation for companies of a size similar to our reduced post-bankruptcy size to determine recommended director compensation.

Directors' 2022 Cash Compensation

The various components of 2022 cash compensation paid to our directors, including employee directors, are as follows:

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
Range of total cash compensation (excluding reimbursements) earned by current directors during 2022	$65,000 to $95,000

Directors' 2022 Equity Awards

Under the Unit Corporation Long Term Incentive Plan ("LTIP"), we may make equity awards to our directors. For information regarding equity awards granted to our non-employee directors during 2022, see the Director Compensation Table. For information regarding equity awards granted to our employee director Mr. Smith during 2022, see the Summary Compensation Table.

Director Compensation Table

The following table shows the total compensation received in 2022 by each of our non-employee directors.

Director Compensation for 2022							
Name [1]	Fees Earned or Paid in Cash [2] ($)	Stock Awards [3] ($)	Option Awards [3] ($)	Non-Equity Incentive Plan Compensation ($)	Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Robert R. Anderson	65,000	239,425	67,482	—	—	—	371,907
Alan J. Carr	85,000	—	—	—	—	—	85,000
Phil Frohlich	75,000	—	—	—	—	—	75,000
Steven B. Hildebrand	85,000	—	—	—	—	—	85,000
Andrei Verona	95,000	—	—	—	—	—	95,000

1. Excludes Director Philip B. Smith, who is also a Named Executive Officer whose compensation, including director compensation, is set forth in the Summary Compensation Table.
2. Represents cash compensation earned in 2022 for service on the Board of Directors or a committee of the Board of Directors.
3. The amounts included in the "Stock Awards" and "Option Awards" columns represent the aggregate grant date fair value of restricted stock units and option awards, respectively, computed in accordance with FASB ASC Topic 718 "Stock Compensation," which excludes the effect of estimated forfeitures. The Stock Awards amount is based on the closing sales price of our common stock on the grant date. For a discussion of the valuation assumptions used in calculating Option Awards value, see Note 15 to our Consolidated Financial Statements included in this annual report on Form 10-K. The totals represent 7,850 restricted stock units and 13,416 option awards granted to Mr. Anderson for advisory consulting services related to the Company's sale of up to all of the assets of its exploration and production segment. The restricted stock units vest in equal monthly installments beginning one month from the grant date, and will be fully vested within thirty months of the grant date. The stock options became 100% exercisable at $45.00 per share one year from the grant date, and they expire on the date that is thirty months after the grant date. On January 6, 2023, in accordance with provisions allowed under the LTIP, the Compensation Committee adjusted the exercise price of all outstanding stock options to $35.00 per share effective January 31, 2023 to account for the special dividend paid on that date. The consulting contract had a six-month term, renewing in one-month terms thereafter until formally terminated.

Executive Compensation

Overview

The 2022 salaries for Messrs. Menefee and Bode were determined by our CEO in October 2020 based on what was deemed to be current market levels at the time. Mr. Smith, originally working for no salary, was granted a nominal salary of $12,000 per year beginning in June 2021, which salary was determined in order to allow him to participate in our health insurance plan. Restricted stock unit awards ("RSUs") and stock option awards were granted to the named executive officers ("NEOs") under the LTIP in October 2021, and annual bonuses were determined in December 2022.

Summary Compensation Table for 2022

The following table sets forth information regarding the compensation paid, distributed, or earned by or for our NEOs for the stated fiscal years:

Name and Principal Position (a)	Year (b)	Salary [(1)] ($) (c)	Bonus [(1)] ($) (d)	Stock Awards [(2)] ($) (e)	Option Awards [(3)] ($) (f)	All Other Compensation [(4)] ($) (g)	Total ($) (h)
Philip B. Smith, CEO and President	2022	12,001	—	—	—	80,000	92,001
	2021	6,500	600	1,374,659	669,089	80,000	2,130,848
Christopher K. Menefee, President, Unit Drilling Company	2022	300,015	150,000	—	—	19,873	469,888
	2021	300,000	100,000	571,540	335,365	24,628	1,331,533
Karl Bode, Senior Vice President, Chief Engineer, Unit Petroleum Company	2022	255,882	175,000	—	—	25,807	456,689
	2021	236,764	11,838	416,364	244,313	23,551	932,830

1. Compensation deferred is listed in the year earned. Mr. Smith began receiving a nominal salary of $1,000 per month effective June 16, 2021, which salary was granted to permit him to participate in our health insurance plan.
2. The amounts included in the "Stock Awards" column represent the aggregate grant date fair value of restricted stock units computed in accordance with FASB ASC Topic 718 "Stock Compensation," which excludes the effect of estimated forfeitures. The amount is based on the closing sales price of our common stock on the grant date. Mr. Smith was granted 18,168 restricted stock units on April 27, 2021, with a grant date fair value of $12.90 per share. Both Mr. Smith and the other two NEOs were granted restricted stock units on October 21, 2021, with a grant date fair value of $34.00 per share. The amount shown does not represent amounts paid to the NEOs.
3. The amounts included in the "Option Awards" column represent the aggregate grant date fair value computed in accordance with FASB ASC Topic 718 "Stock Compensation" but does not include any impact of estimated forfeitures. For a discussion of the valuation assumptions used in calculating these values, see Note 15 to our Consolidated Financial Statements included in this annual report on Form 10-K. The amount shown does not represent amounts paid to the NEOs.
4. Components of the items in this column for 2022 are detailed in the table below.

Name	Director Compensation [(a)] ($)	Executive Disability Insurance Premium ($)	401(k) Match [(b)] ($)	Personal Car Allowance ($)	Club Membership ($)	Total "All Other Compensation" ($)
Philip B. Smith	80,000	—	—	—	—	80,000
Christopher K. Menefee	—	2,764	12,001	—	5,109	19,874
Karl Bode	—	7,607	12,200	6,000	—	25,807

a. Reflects fees earned or paid in cash for service as a member of our Board of Directors and its chair.
b. Match was made in cash.

Outstanding Equity Awards at End of 2022

The following table sets forth information about our NEOs' outstanding equity awards at the end of 2022:

Outstanding Equity Awards at Fiscal Year-End						
	Options Awards				Stock Awards	
Name (a)	Number of securities underlying unexercised options - exercisable (#) (b)	Number of securities underlying unexercised options - unexercisable [(1)] (#) (c)	Option exercise price [(2)] ($) (d)	Option expiration date (e)	Number of shares or units of stock that have not vested [(3)] (#) (f)	Market value of shares or units of stock that have not vested [(4)] ($) (g)
Philip B. Smith	19,564	39,128	45.00	10/21/2026	29,717	1,719,426
Christopher K. Menefee	9,806	19,612	45.00	10/21/2026	11,206	648,379
Karl Bode	—	14,287	45.00	10/21/2026	8,164	472,369

1. Each option grant has a five-year term. Option awards were granted on October 21, 2021, and become exercisable in three equal installments on October 1st of each of 2022, 2023, and 2024. The option exercise price was $45.00 per share as of December 31, 2022.
2. On January 6, 2023, in accordance with provisions allowed under the LTIP, the Compensation Committee adjusted the Option exercise price by $10.00 to $35.00 per share to account for the special dividend paid on January 31, 2023.
3. The vesting schedule for the restricted stock units that have not vested are as follows for each NEO: For Messrs. Menefee and Bode, and for 33,538 shares held by Mr. Smith, the awards vest in three equal installments on November 21, 2022, October 1, 2023, and October 1, 2024; Mr. Smith has an additional award of 18,168 shares that vests in four equal installments on May 27, 2022, September 3, 2022, September 3, 2023, and September 3, 2024.
4. Market value is determined based on the market value of our common stock of $57.86, the quoted closing price of our common stock on the OTC Pink on December 30, 2022, the last trading day of the year.

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

Directors and Executive Officers

This table shows the number of shares of our common stock beneficially owned by each current director, each NEO, and all current directors and executive officers as a group as of March 14, 2023, with all shares directly owned unless otherwise noted:

Stock Owned by Our Directors and Executive Officers			
Name of Beneficial Owner	Common Stock (a)	Options Exercisable and RSUs Vesting within 60 days (b)	Total (c)
Robert R. Anderson	12,748	13,939 [(1)]	26,687
Alan J. Carr	—	—	—
Phil Frohlich [(2)]	—	—	—
Steven B. Hildebrand	—	—	—
Philip B. Smith	20,264	19,564	39,828
Andrei Verona	—	—	—
Christopher K. Menefee	—	9,806	9,806
Karl Bode	3,129	—	3,129
All directors and executive officers as a group (eight people) [(3)]	36,141	43,309	79,450

1. Represents 13,416 stock options that vested on January 7, 2023, and restricted stock units that will vest under the terms of Mr. Anderson's January 2022 Consulting Contract with the Company, as follows: 261 shares on April 7, 2023, and 261 shares on May 7, 2023.
2. Mr. Frohlich manages Prescott Group Capital Management, which owns 3,517,707 shares, or approximately 36% of our issued and outstanding shares of common stock as of March 14, 2023, as set forth in the table below and not included in Mr. Frohlich's share count in this table.
3. No officer or director individually owns more than 1% of our issued and outstanding shares of common stock, nor do our officers and directors as a group. Ownership percentages are based on the number of our issued and outstanding shares of common stock on March 14, 2023.

Stockholders Owning More Than 5% of Our Common Stock

This table sets forth information about the beneficial ownership of our common stock by the only stockholders we know of who own over five percent of our common stock. Holders of more than five percent of our common stock have not been required to file ownership reports with the SEC.

Stockholders Who Own More Than 5% of Our Common Stock		
Name and Address	Amount and Nature of Beneficial Ownership (1)	Percent of Class (2)
Prescott Group Capital Management, LLC 1924 S. Utica Avenue, Suite 1120 Tulsa, Oklahoma 74104	3,517,707	36.26%
RBC Global Asset Management Inc. RBC Centre 155 Wellington Street West, Suite 2300 Toronto, Ontario, Canada M5V 3K7	922,623	9.59%
NYL Investors LLC 51 Madison Avenue New York, New York 10010	623,361	6.48%

1. Beneficial ownership for Prescott Group Capital Management, LLC and NYL Investors LLC is as confirmed by the stockholders in March 2023. Information for RBC Global Asset Management Inc. is based on Schedule 13G filed with the SEC on February 14, 2023. Information is provided for reporting purposes only and should not be construed as an admission of actual beneficial ownership.
2. Based on the number of issued and outstanding shares of our common stock as of March 14, 2023.

Securities Authorized for Issuance Under Equity Compensation Plans as of December 31, 2022

Securities Authorized for Issuance Under Equity Compensation Plans			
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (1) (a)	Weighted-average exercise price of outstanding options, warrants and rights (2) ($) (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3) (c)
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders	698,213	45.00	290,142
Total	698,213	45.00	290,142

1. Includes 323,379 shares of RSUs, all of which were not approved by security holders. Our Long Term Incentive Plan was approved by the requisite creditors as part of our plan of reorganization, which was confirmed by order of the U.S. Bankruptcy Court on August 6, 2020. The material terms of our LTIP are described below.
2. Excludes the shares issuable upon the vesting of RSUs included in column (a), for which there is no weighted-average exercise price. On January 6, 2023, in accordance with the provisions allowed under the LTIP, the Compensation Committee adjusted the Option exercise price by $10.00 to $35.00 per share to account for the special dividend paid on January 31, 2023.
3. Represents shares available for issuance under our Long Term Incentive Plan.

Material Terms of Long Term Incentive Plan

Overview. Our LTIP was adopted in connection with our reorganization and became effective as of September 3, 2020. The following is a summary of the material terms of the LTIP. This summary is not complete. For more information concerning the LTIP, we refer you to the full text of the plan, which was filed as an exhibit to our Current Report on Form 8-K filed September 10, 2020.

The purpose of the LTIP is to attract, retain and motivate employees, officers, directors, consultants, and other service providers of the Company and its affiliates. The LTIP provides for the grant, from time to time, at the discretion of the Board of Directors or a Board of Directors committee, of Options, SARs, Restricted Stock, Restricted Stock Units, Stock Awards, Dividend Equivalents, Other Stock-Based Awards, Cash Awards, Performance Awards, Substitute Awards, or any combination of those awards.

Subject to adjustment in the event of certain transactions or changes of capitalization in accordance with the LTIP, 903,226 shares of the new common stock of the reorganized Company, par value $0.01 per share ("stock") have been reserved for issuance by awards to be issued under the LTIP. Shares available to be delivered under the LTIP will be made available from (i) authorized but unissued shares of stock; (ii) stock held in the treasury of the Company; or (iii) previously-issued shares of stock reacquired by the Company. 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 by issuance of other awards under the LTIP.

Eligible recipients of awards under the LTIP include any individual who, as of the date of grant, is an officer or employee of the Company or its affiliates and any other individual who provides services to the Company or its affiliates, including one of its directors. An employee on leave from the Company is considered eligible for awards under the LTIP.

Administration. The LTIP is administered by our compensation committee, which has discretion to determine the individuals to whom awards may be granted under the plan, the number of shares of our stock or the amount of cash subject to each award, the type of award, the manner in which such awards will vest and the other conditions applicable to awards. The compensation committee is empowered to clarify, construe or resolve any ambiguity in any provision of the LTIP or any award agreement and adopt such rules, forms, instruments and guidelines for administering the LTIP as it deems necessary or proper. The committee may delegate its powers to a subcommittee, a director, or an officer, if the delegation does not violate any applicable law.

Agreements. Awards granted under the LTIP will be evidenced by award agreements that provide additional terms and conditions associated with such awards, as determined by the compensation committee in its discretion. In the event of any conflict between the provisions of the LTIP and any such award agreement, the provisions of the LTIP will control.

Award Types. Types of awards available under the LTIP, which may be granted either alone, in addition to, or in tandem with any other award, include:

- Options - These include Incentive Stock Options ("ISO"s), which are intended to meet the ISO definition of Section 422 of the Internal Revenue Code, as well as Nonstatutory Options, which are any option that is not an ISO. Net settlement and cashless exercise are available methods of payment. No option may be exercisable for more than ten years following the grant date or, for persons owning stock with more than 10% of the total combined voting power of all classes of stock of the Company or its subsidiaries, five years from the grant date.

- Stock Appreciation Rights ("SAR"s) - A SAR is the right to receive, on exercise, an amount equal to the product of the excess of the fair market value of a share of stock on the date of exercise over the grant price of the SAR and the number of shares of stock subject to the exercise of the SAR. No SAR may be exercisable for more than ten years following the grant date.

- Restricted Stock - Restricted Stock is stock granted subject to certain restrictions and a risk of forfeiture. During the period of restriction, the stock may not be transferred, sold, pledge, hedged, hypothecated, margined or otherwise encumbered by the recipient.

- Restricted Stock Units ("RSU"s) - An RSU is a grant to receive stock, cash, or a combination of stock and cash at the end of a specified period, and may include any restrictions imposed by the compensation committee. Settlement of RSUs will occur on vesting or expiration of the specified period, and will be done by delivery of a number of shares of stock equivalent to the number of RSUs for which settlement is due, or cash in the amount of the fair market value of the specified number of shares of stock equal to the number of RSUs for which settlement is due, or a combination thereof, as determined by the compensation committee.

- Stock Awards - Stock awards are unrestricted shares of stock, and may be granted as a bonus, as additional compensation, or in lieu of cash in such amounts and subject to such terms as the compensation committee determines.

- Dividend Equivalents - Dividend Equivalents are rights to receive cash, stock or other awards or other property equal in value to dividends paid with respect to a specified number of shares of stock, or other periodic payments. Dividend Equivalents granted in connection with another award will be subject to the same restrictions or forfeiture risk as the award with respect to which the dividends accrue and will not be paid until that award has vested and been earned.

- Other Stock-Based Awards - The compensation committee may grant other awards denominated in or payable in, valued in whole or part by reference to, or otherwise based on, or related to, stock, as determined by the compensation committee, including convertible or exchangeable debt securities, other rights convertible or exchangeable into stock, purchase rights for stock, awards with value and payment contingent on performance of the Company or other factors determined by the compensation committee, and awards valued by reference to the book value of stock or the value of securities of, or the performance of, affiliates of the Company.

- Cash Awards - Cash Awards are awards denominated in cash.

- Substitute Awards - The compensation committee may grant awards in substitution or exchange for any other award granted under the LTIP or another plan of the Company or an affiliate. Substitute Awards may be granted in connection with a merger, consolidation, or acquisition of another entity or the assets of another entity.

- Performance Awards - The compensation committee may grant awards under the LTIP that are conditioned on one or more business criteria or individual performance criteria and a targeted level or levels of performance with respect to each criteria. Conditions or goals may be based on business criteria for the Company, on a consolidated basis, and/or for specified affiliates or business units of the Company. Conditions and goals may be set on an absolute or relative basis, and can differ for different award recipients. If significant events occur which the compensation committee expects to have a substantial effect on the applicable performance conditions, the compensation committee may revise the performance conditions. The performance period will be as determined by the compensation committee in its discretion but shall not exceed ten years. Amounts determined to have vested will be paid by March 15th of the year following the year included in the last day of the applicable performance period. Settlement may be made in cash, stock, or other awards or property, as determined by the compensation committee. Awards may be increased or decreased in the compensation committee's discretion.

Tax Withholding. The Company or its affiliates may withhold from any award or payment under an award the amount needed to cover taxes due or potentially payable and take such other action to satisfy payment of withholding taxes and other tax obligations related to any award in amounts as may be determined by the compensation committee in its sole discretion.

Transferability of Awards. Other than as permitted to be transferred by the compensation committee to an immediate family member or a family trust (or similar entities), or as transferred under a domestic relations orders, options and SARs shall be exercisable only by the participant during the participant's lifetime or by the person to whom those rights pass by will or the laws of descent and distribution. ISOs may not be transferred other than by will or the laws of descent and distribution. If provided by the compensation committee in an award agreement, an award may be transferred without consideration to immediate family members or related family trusts, limited partnerships, or similar entities or on such terms and conditions as the compensation committee may from time to time establish, and awards may be transferred under a qualified domestic relations order.

Form and Timing of Payment under Awards. Payments may be made in such forms as the compensation committee may determine in its discretion, including cash, stock, other awards or property, and may be made in lump sum, installments or on a deferred basis as long as the deferred or installment basis is set forth in an award agreement. Payments may include provisions for crediting or paying reasonable interest on installment or deferral amounts or the granting of Dividend Equivalents or other amounts in respect of installment or deferred payments denominated in stock.

Form of Stock Awards. Stock or other securities of the Company under an award under the LTIP may be evidenced in any manner deemed appropriate by the compensation committee including certificated stock, book entry, electronic or otherwise, and shall be subject to such restrictions as the compensation committee deems advisable or as required by applicable law. Appropriate legends will be inscribed.

Adjustment of Awards. In the event of a corporate event or transaction such as a merger, consolidation, reorganization, recapitalization, stock dividend, stock split, reverse stock split or similar event or transaction the compensation committee may make certain adjustments to awards, including, in its sole discretion, substitution or adjustment of the number and kind of shares that may be issued under the LTIP or under particular awards, the grant price or purchase price applicable to outstanding awards, and other value determinations applicable to the LTIP or outstanding awards. In the event we experience a change in control (as defined in the LTIP), the compensation committee may, but is not obligated to, make adjustments to the terms and conditions of outstanding awards, including, without limitation:

- acceleration of vesting and exercisability of awards, including subjecting the accelerated award to a time limitation after which rights under the award terminate;

- redemption or assumption in whole or in part of awards, for fair value or no value, depending on the award type and the price of the Company's stock at the time of the change of control;

- cancellation of awards remaining subject to restriction, with no payment for the award;

- make adjustments to outstanding awards as the committee deems appropriate to reflect the change of control or other such event, including the substitution, assumption, or continuation of awards by the successor Company or a parent or subsidiary of the successor Company.

Limitations on Transfer of Stock Awarded under the LTIP. Prior to any Qualifying Public Offering, as defined in the LTIP, the Company has a right of first refusal and a purchase option to purchase shares of stock from LTIP participants ceasing to be employees or service providers of the Company, as detailed in Section 9 of the LTIP. Appropriate stock legends will be inscribed denoting the foregoing transfer restrictions. Also as detailed in Section 9 of the LTIP, in connection with a Qualifying Public Offering, as defined in the LTIP, holders of shares of Company stock awarded under the LTIP may be restricted from transferring those shares for a specified "lock-up" period of time following the date of such an offering.

Section 409A of the Internal Revenue Code. Awards granted under the LTIP are intended but not required to comply with Section 409A of the Internal Revenue Code ("Section 409A"). The compensation committee may adjust the timing of award payments to comply with requirements of Section 409A and the "Nonqualified Deferred Compensation Rules," as defined in the LTIP. The LTIP provides that the Nonqualified Deferred Compensation Rules as so defined are incorporated by reference into the LTIP and control over the LTIP or any award agreement.

Clawback. The LTIP and all awards granted under it are subject to any clawback policies the Company may adopt, which could result in reduction, cancellation, forfeiture, or recoupment in certain circumstances of wrongful conduct.

Amendment and Termination. The compensation committee may amend or terminate the LTIP or any award agreement at any time without the consent of the Company's stockholders or LTIP participants, except that any amendment or alteration, including any increase in any share limitation, will be subject to stockholder approval if required by any federal or state law or regulation. The committee may otherwise in its discretion determine to submit changes to the plan for stockholder approval. Without the consent of an affected participant under a previously granted and outstanding award, the committee may not act to materially diminish the participants' rights under the LTIP or any award, provided that any adjustment in connection with any subdivision, consolidation, recapitalization, change of control or other reorganization is deemed not to materially and adversely affect the rights of any participant. No awards will be granted under the LTIP after September 3, 2030.

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

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. 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 and Cactus Drilling Company. Payments made to Kaiser Francis Oil Company totaled $5.7 million and $5.7 million during 2022 and 2021, respectively, while payments received totaled $12.9 million and $6.2 million during 2022 and 2021, respectively. No payments were made to Cactus Drilling Company during 2022 compared to $0.8 million during 2021. Additionally, on January 7, 2022 (the "grant date"), Mr. Anderson entered into a consulting contract with the Company. Under the terms of the consulting contract, Mr. Anderson agreed to provide advisory consulting services related to the Company's sale of up to all of the assets of its exploration and production segment in exchange for awards of 7,850 restricted stock units and 13,416 stock options having a total estimated grant date fair value of $0.3 million. The restricted stock units vest in equal monthly installments beginning one month from the grant date, and will be fully vested within thirty months of the grant date. The stock options became 100% exercisable at $45.00 per share one year from the grant date, and they expire on the date that is thirty months after the grant date. On January 6, 2023, in accordance with provisions allowed under the LTIP, the Compensation Committee adjusted the exercise price of all outstanding stock options to $35.00 per share effective January 31, 2023 to account for the special dividend paid on that date. The consulting contract had a six-month term, renewing in one-month terms thereafter until formally terminated.

Director Independence Determination

Our common stock is not listed on any national exchange or quoted on any inter-dealer quotation service that imposes independence requirements on our Board of Directors or any committee thereof. Under the corporate governance standards of the New York Stock Exchange ("NYSE"), generally a director does not qualify as independent if the director (or in some cases, members of the director's immediate family) has, or in the past three years has had, certain relationships or affiliations with us, our external or internal auditors or other companies that do business with us.

The Board of Directors has determined that all of our directors, except Messrs. Smith, Frohlich, and Anderson are independent under the NYSE standards. The Board of Directors determined that none of the independent directors has any material relationship with us that could impair such individual's independence. Mr. Smith is not considered to be an independent director because of his employment as one of our executive officers. Mr. Frohlich is not considered to be independent because he is considered to be an affiliate based on his management of Prescott Group Capital Management LLC, which controls approximately 36% of our issued and outstanding common stock as of March 14, 2023. Mr. Anderson is not considered to be independent because he has a consulting contract with us.

Each member of each of our Audit and Compensation Committees also qualifies as independent under NYSE standards, other than Mr. Frohlich, who serves on our Audit Committee.

Item 14. Principal Accountant Fees and Services

Fees Incurred for Grant Thornton LLP

Grant Thornton LLP was our independent registered accounting firm for fiscal years 2022 and 2021. This table shows the fees for professional audit services provided for the audit of our annual financial statements paid to Grant Thornton LLP for the stated years.

Type of Service	2022	2021
Audit Fees (1)	$950,000	$909,153
Audit-Related Fees (2)	$46,917	—
Tax Fees (3)	$58,535	$21,865
All Other Fees	—	—
Total	$1,055,452	$931,018

1. Audit fees include professional services for the audits of our consolidated financial statements and the Superior Pipeline Company, L.L.C. financial statements, review of our quarterly condensed consolidated financial statements, audit services provided for the issuance of consents, and assistance with review of documents filed with the SEC.
2. Audit-related fees include professional services for the audit of the Unit Corporation 401(k) Employee Thrift Plan's financial statements.
3. 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

Consistent with SEC policies regarding auditor independence, the audit committee has responsibility for appointing, setting compensation, and overseeing the work of the independent registered 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 registered 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 registered 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 registered 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 registered 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 registered 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 registered public accounting firm's services within each category. The fees are budgeted and the audit committee requires the independent registered 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 registered 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 registered 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.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Schedules, and Exhibits:

1. *Financial Statements:*

Included in Part II of this report:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2022 and 2021
Consolidated Statements of Operations for the years ended December 31, 2022 and 2021
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2022 and 2021
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2022 and 2021
Consolidated Statements of Cash Flows for the years ended December 31, 2022 and 2021
Notes to Consolidated Financial Statements

2. *Financial Statement Schedules:*

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

3. *Exhibits:*

The exhibit numbers in the following list correspond to the numbers assigned such exhibits in the Exhibit Table of Item 601 of Regulation S-K.

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 Consulting Agreement with Robert Anderson (filed as Exhibit 10.4 to Unit's Form 10-K, dated March 31, 2022, which is incorporated by reference herein).
10.5	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).
10.6	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).
10.7†	Employment Agreement, dated October 26, 2020, between Unit Corporation and Thomas Sell (filed as Exhibit 10.1 to Unit's Form 8-K, dated December 11, 2020, which is incorporated by reference herein).
10.8†	Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.8 to Unit's Form 10-K, dated March 31, 2022, which is incorporated by reference herein).
10.9†	Amendment No. 1 to Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.9 to Unit's Form 10-K, dated March 31, 2022, which is incorporated by reference herein).
10.10	Amended and Restated Management Services and Operating Agreement between SPC Midstream Operating, L.L.C. and Superior Pipeline Company, L.L.C. (filed as Exhibit 10.10 to Unit's Form 10-k, dated March 31, 2022, which is incorporated by reference herein).
10.11	Amended and Restated Credit Agreement, dated as of September 3, 2020, among Unit Corporation, Unit Drilling Company, Unit Petroleum Company, the lenders party thereto from time to time, the guarantors party thereto and BOKF, NA dba Bank of Oklahoma as administrative agent and collateral agent (filed as Exhibit 10.1 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.12	First Amendment to Amended and Restated Credit Agreement dated April 6, 2021 (filed as Exhibit 10.1 to Unit's Form 10-Q, dated May 12, 2021, which is incorporated by reference herein).
10.13	Second Amendment to Amended and Restated Credit Agreement effective July 26, 2021 (filed as Exhibit 10.1 to Unit's Form 10-Q, dated August 16, 2021, which is incorporated by reference herein).
10.14	Third Amendment to Amended and Restated Credit Agreement effective October 20, 2021 (filed as Exhibit 10.1 to Unit's Form 10-Q, dated November 12, 2021, which is incorporated by reference herein).
10.15	Fourth Amendment to Amended and Restated Credit Agreement effective November 1, 2022 (filed as Exhibit 10.1 to Unit's Form 10-Q, dated November 10, 2022, which is incorporated by reference herein).
10.16	Credit Agreement dated May 10, 2018, by and among Superior Pipeline Company, L.L.C. and BOKF, NA DBA Bank of Oklahoma, as Administrative Agent, and the institutions named therein (as lenders) (filed as Exhibit 10.1 to Unit's Form 8-K dated May 16, 2018, which is incorporated by reference herein).
10.17	First Amendment to Credit Agreement, dated June 27, 2018, by and among Superior Pipeline Company, L.L.C. and the subsidiaries named therein (as borrowers), BOKF, NA dba Bank of Oklahoma, as Administrative Agent, and the institutions named therein (as lenders) (filed as Exhibit 10.1(b) to Unit's Form 10-Q, dated August 9, 2018, which is incorporated by reference herein).
10.18	Amended and Restated Credit Agreement, dated April 29, 2022 by and among Superior Pipeline Company, L.L.C. and BOKF, NA DBA Bank of Oklahoma as Administrative Agent, and the institutions named therein (as lenders) (filed as Exhibit 10.1 to Unit's Form 10-Q, dated May 12, 2022, which is incorporated by reference herein).
10.19	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).
10.20	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).
10.21	Second Amended and Restated Limited Liability Company Agreement of Superior Pipeline Company, L.L.C., dated as of July 1, 2019 (filed as Exhibit 10.1 to Unit's Form 10-Q, dated October 21, 2020, which is incorporated by reference herein).
10.22	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Superior Pipeline Company, L.L.C., dated as of July 1, 2019 (filed as Exhibit 10.2 to Unit's Form 10-Q, dated October 21, 2020, which is incorporated by reference herein).
10.23	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement of Superior Pipeline Company, L.L.C., dated as of March 1, 2022 (filed as Exhibit 10.21 to Unit's Form 10-K, dated March 31, 2022, which is incorporated by reference herein).
10.24	Purchase and Sale Agreement, dated March 28, 2018, by and between Unit Corporation and SP Investor Holdings, LLC (filed as Exhibit 10.1 to Unit's Form 10-Q, dated May 3, 2018, which is incorporated by reference herein).

21	Subsidiaries of the Registrant (filed herewith).
23.1	Consent of Ryder Scott Company, L.P. (filed herewith).
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herewith).
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act (filed herewith).
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
99.1	Ryder Scott Company, L.P. Summary Report (filed herewith).
101.INS	XBRL Instance Document. The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the inline XBRL document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File. The cover page interactive data file does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document (contained in Exhibit 101)

† Indicates a management contract or compensatory plan identified under the requirements of Item 15 of Form 10-K.

Item 16. Form 10-K Summary

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

UNIT CORPORATION

DATE: March 17, 2023

By: /s/ PHILIP B. SMITH

PHILIP B. SMITH
President and Chief Executive Officer and Chairman of the Board
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 17th day of March, 2023.

Name	Title
/s/ PHILIP B. SMITH **Philip B. Smith**	President and Chief Executive Officer and Chairman of the Board (Principal Executive Officer)
/s/ THOMAS D. SELL **Thomas D. Sell**	Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)
/s/ ROBERT ANDERSON **Robert Anderson**	Director
/s/ ALAN J. CARR **Alan J. Carr**	Director
/s/ PHIL FROHLICH **Phil Frohlich**	Director
/s/ STEVEN B. HILDEBRAND **Steven B. Hildebrand**	Director
/s/ ANDREI VERONA **Andrei Verona**	Director

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

All the companies listed below are included in Unit Corporation's consolidated financial statements. Except as otherwise indicated below, Unit Corporation has 100% direct or indirect ownership of, and ultimate voting control in, each of these companies. The list is as of December 31, 2022 and excludes subsidiaries which are primarily inactive or taken singly, or as a group, do not constitute significant subsidiaries:

Subsidiary	State or Province of Incorporation	Percentage Owned
Unit Drilling Company	Oklahoma	100%
Unit Petroleum Company	Oklahoma	100%

Exhibit 23.1

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the filing of our reserves audit report dated January 30, 2023, as Exhibit 23.1 to the Unit Corporation annual report on Form 10-K for the year ended December 31, 2022 and to any reference made to us on that form 10-K.

/s/ RYDER SCOTT COMPANY, L.P.

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

Houston, Texas
March 17, 2023

Exhibit 31.1

302 CERTIFICATIONS

I, Philip B. Smith, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 17, 2023

/s/ Philip B. Smith
PHILIP B. SMITH
President and Chief Executive Officer

Exhibit 31.2

302 CERTIFICATIONS

I, Thomas D. Sell, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 17, 2023

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

Exhibit 32

CERTIFICATION
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(SUBSECTIONS (A) AND (B) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Unit Corporation a Delaware corporation (the "Company"), does hereby certify, to such officer's knowledge, that:

The Annual Report on Form 10-K for the year ended December 31, 2022 (the "Form 10-K") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2022 and 2021, and for the twelve months ended December 31, 2022 and 2021.

Dated: March 17, 2023

By: /s/ Philip B. Smith
Philip B. Smith
President and Chief Executive Officer

Dated: March 17, 2023

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

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-K or as a separate disclosure document.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Unit Corporation and will be retained by Unit Corporation and furnished to the Securities and Exchange Commission or its staff on request.

UNIT CORPORATION

Estimated

Net Future Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2022

\s\ Robert J. Paradiso

Robert J. Paradiso, P.E.
TBPELS License No. 111861
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
FAX (713) 651-0849
TELEPHONE (713) 651-9191

January 30, 2023

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 th proved reserves as of December 31, 2022 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 Ga Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations)Our reserves audit, completed on January 18, 2023 and presented herein, was prepared for public disclosure by Unit in filings made with the SEC in accordance with the disclosure requirements set forth ir 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, 2022.The properties reviewed by Ryder Scott incorporate 448 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 2022. 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, 2022.

The properties reviewed by Ryder Scott account for a portion of Unit's total proved discounted future net income using SEC hydrocarbon pric parameters as of December 31, 2022. Based on the reserves and income projections prepared by Unit, the audit conducted by Ryder Scott addresses approximately 86 percent of the total proved discounted future net income at 10% of Unit as of December 31, 2022.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil an 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, 2022 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, 2022, 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 and for those that we did not review are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests of
Unit Corporation
As of December 31, 2022

	Total Proved Developed Producing
Net Reserves of Properties Audited by Ryder Scott	
Oil/Condensate – MBarrels	6,670
Plant Products – MBarrels	17,385
Gas - MMcf	170,049
MBOE	52,397
Net Reserves of Properties Not Audited by Ryder Scott	
Oil/Condensate – MBarrels	1,011
Plant Products – MBarrels	2,747
Gas - MMcf	42,360
MBOE	10,818
Total Net Reserves	
Oil/Condensate – MBarrels	7,681
Plant Products – MBarrels	20,132
Gas - MMcf	212,409
MBOE	63,215

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 proved reserves prepared by Unit for the properties that we reviewed were estimated by performance methods. All of the reserves attributable to producing wells and/or reservoirs were estimated by performance 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, 2022 in those cases where such data were considered to be definitive. 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. Unit has informed us they do not have any fixed price contractual arrangements.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2022 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. In certain geographic areas, 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 each o the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realiz Prices
United States	Oil/Condensate	WTI Cushing	$93.67/bbl	$95.00/bbl
	NGLs	WTI Cushing	$93.67/bbl	$39.78/bbl
	Gas	Henry Hub	$6.357/MMBTU	$6.52/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 o 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 from wells currently on production. 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 from wells currently on production 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, 2022 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, 2022. The other properties represent approximately 14 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, 2022.

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 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
Vice President

[SEAL]

RJP (HGA)/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 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 2022 continuing education hours, Mr. Paradiso attended 6 hours of formalized training during the 2021 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 24½ hours of formalized in-house training during 2022 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, Greenhouse Gas Emissions statements, reservoir engineering, geoscience and petroleum economics evaluation methods and procedures, and ethics for consultants.

Based on his educational background, professional training and more than 43 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 Reportin 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; Fina 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 complet 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, ga 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.*

<u>Note to paragraph (a)(26):</u> 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 (<u>i.e.</u>, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (<u>i.e.</u>, 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.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(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 excerp from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

<u>DEVELOPED RESERVES (SEC DEFINITIONS)</u>

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.

<u>Developed Producing (SPE-PRMS Definitions)</u>

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.

<u>Developed Producing Reserves</u>
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.