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, 2021
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
(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. ☐

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, 2021, 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, 2021) held by non-affiliates was approximately $127.7 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 31, 2022, 10,050,561 shares of the registrant's common stock were outstanding.

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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.

SARs – Stock appreciation rights.

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:

2011 Notes – The $250.0 million 6.625% senior subordinated notes due 2021 issued in 2011.

2012 Notes – The $400.0 million 6.625% senior subordinated notes due 2021 issued in 2012.

BOKF – Bank of Oklahoma Financial Corporation.

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

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

DIP Credit Agreement – The credit agreement the company entered into on May 27, 2020 with the lenders under its then existing Unit credit agreement.

Effective 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 replacing the DIP Credit Agreement and the Unit credit agreement.

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 Effective 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.

Predecessor – The company before the Effective Date.

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.

Predecessor Period – Relates to the financial position and results of operations of the company for the period of January 1, 2020 through August 31, 2020.

Successor Period – Relates to the financial position and results of operations of the company for the period of September 1, 2020 through December 31, 2021.

Superior – Our 50% owned subsidiary Superior Pipeline Company, L.L.C., and its subsidiaries.

The Notes – Collectively, the 2011 Notes and 2012 Notes.

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, and the market's receptiveness, to execute a strategic divestiture process;
- our ability to utilize the benefits of net operating losses and other deferred tax assets against potential future taxable income, including those that may be generated by a strategic divestiture process;
- our ability to retain or recruit key personnel throughout a strategic divestiture process;
- the number of gathering systems and processing plants we may plan to construct or acquire;
- volumes and prices for the natural gas we gather and process;
- 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 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;

- our estimates of any ceiling test write-downs or other potential asset impairments we may have to record in future periods; and
- our ability to carry out our post reorganization plans.

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;
- 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, 2021

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. Today, besides our drilling operations, we have operations in the exploration and production and mid-stream areas. 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 account. 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 is expanding the Divestiture Program to now include the potential sale of additional properties, including up to all of UPC's oil and gas properties and reserves. On January 20, 2022, the company announced that it has retained a financial advisor and launched the process.
- *Contract Drilling* – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for others and our account.
- *Mid-Stream* – carried out by Superior. This segment buys, sells, gathers, processes, and treats natural gas for third parties and our account.

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

This table provides certain information about our assets as of December 31, 2021:

Oil and Natural Gas	
Total number of wells in which we own an interest	5,253
Contract Drilling	
Total number of drilling rigs available for use	21
Mid-Stream	
Number of natural gas treatment plants we own	3
Number of processing plants we own	12
Number of natural gas gathering systems we own	18

Emergence From Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On May 22, 2020, the Debtors filed petitions for reorganization under Chapter 11 of Title 11 of the United States Code (Bankruptcy 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 filed their Plan and the related disclosure statement with the bankruptcy court on June 9, 2020. On August 6, 2020, the bankruptcy court entered the "Findings of Fact, Conclusions of Law, and Order (I) Approving the Disclosure Statement on a Final Basis and (II) Confirming the Debtors' Amended Joint Chapter 11 Plan of Reorganization" [Docket No. 340] (Confirmation Order) confirming the Plan. On September 3, 2020, the Debtors emerged from the Chapter 11 Cases.

2021 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

- Revenues before eliminations increased by 69% from 2020 primarily due to higher average commodity pricing, partially offset by lower production volumes.
- Operating costs before eliminations decreased 43% from 2020.
- Capital expenditures increased 89% from 2020.

Contract Drilling

- Revenues decreased 18% from 2020 primarily due to the absence of 2020 rig termination and standby fees. Average rig utilization increased 8% to 10.9 rigs during 2021 while there was a 4% decrease in average dayrate to $17,987.
- Operating costs decreased 7% from 2020 primarily due to a decrease in rig fleet from 58 to 21 in 2021.

Mid-Stream

- Revenues before eliminations increased 87% and operating expenses before eliminations increased 114% from 2020 primarily due to higher commodity pricing, partially offset by lower volumes.
- Acquired a cryogenic processing plant, approximately 1,620 miles of low-pressure gathering pipeline, and related compressor stations located in southern Kansas in November 2021.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 23 - Industry Segment Information of our Notes to Consolidated Financial Statements in Item 8 of this report for information about each of our segment's revenues, profits or losses, and total assets.

OIL AND NATURAL GAS

General. All our oil and natural gas properties are in the United States. Our producing oil and natural gas properties, unproved properties, and related assets are mainly in Oklahoma and Texas, and to a lesser extent Kansas, Louisiana, Montana, North Dakota, Utah, and Wyoming.

When we are the operator of a property, we try to use one of our drilling rigs to drill any wells on the property, and we also use our mid-stream segment to gather our gas if it is economical to do so.

This table presents certain information regarding our oil and natural gas operations as of December 31, 2021:

	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2021 Average Net Daily Production Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
Total	5,253	1,450.67	5	0.02	79,485	4,424	7,189

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 is expanding the Divestiture Program to now include the potential sale of additional properties, including up to all of UPC's oil and gas properties and reserves. On January 20, 2022, the company announced that it has retained a financial advisor and launched the process.

On March 8, 2022, the company closed on the sale of wells and related leases located near the Oklahoma Panhandle for $5.0 million, subject to customary closing and post-closing adjustments with an effective date of December 1, 2021. No gain or loss was recognized as the sale of these assets 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 $19.5 million, subject to customary closing and post-closing adjustments. No gain or loss was recognized as the sale of these assets 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 related leases located in Reno and Stafford Counties, Kansas for $7.1 million, subject to customary closing and post-closing adjustments. No gain or loss was recognized as the sale of these assets did not result in a significant alteration of the full cost pool.

We also sold $5.0 million of other non-core oil and natural gas assets, net of related expenses, during the year ended December 31, 2021. No gain or loss was recognized as the sale of these assets did not result in a significant alteration of the full cost pool.

Well and Leasehold Data. The following tables identify certain information regarding our oil and natural gas exploratory and development drilling operations:

	Successor				Predecessor	
	Year Ended December 31, 2021		Four Months Ended December 31, 2020		Eight Months Ended August 31, 2020	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Development:						
Oil	10	3.7	2	0.3	10	0.1
Natural Gas	—	—	1	—	12	0.3
Dry	—	—	—	—	—	—
Total development	10	3.7	3	0.3	22	0.4
Exploratory:						
Oil	13	0.7	—	—	—	—
Natural gas	—	—	—	—	—	—
Dry	1	—	—	—	—	—
Total exploratory	14	0.7	—	—	—	—
Total wells drilled	24	4.4	3	0.3	22	0.4

	Year Ended December 31,			
	2021		2020	
	Gross	Net	Gross	Net
Wells producing or capable of producing:				
Oil	736	141.2	1,534	604.8
Natural gas	2,380	649.0	4,601	1,598.3
Total	3,116	790.2	6,135	2,203.1

We did not develop any previously booked proved undeveloped oil and natural gas reserves in 2021 or 2020.

The following table summarizes our leasehold acreage at December 31, 2021:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net [1]	Gross	Net
Total	489,308	270,457	8,470	4,212	497,778	274,669

1. Approximately 100% of the net undeveloped acres are covered by leases that will expire in the years 2022—2024 unless drilling or production extends those leases.

Price and Production Data. The following tables identify 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:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
Average sales price per barrel of oil produced:			
Price before derivatives	$ 66.50	$ 39.23	$ 35.14
Effect of derivatives	(16.47)	(1.94)	(3.16)
Price including derivatives	$ 50.03	$ 37.29	$ 31.98
Average sales price per barrel of NGLs produced:			
Price before derivatives	$ 23.41	$ 9.28	$ 4.83
Effect of derivatives	—	—	—
Price including derivatives	$ 23.41	$ 9.28	$ 4.83
Average sales price per Mcf of natural gas produced:			
Price before derivatives	$ 3.55	$ 1.91	$ 1.11
Effect of derivatives	(0.62)	0.01	0.03
Price including derivatives	$ 2.93	$ 1.92	$ 1.14

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
Oil production (MBbls):			
Jazz Wilcox field	126	61	184
Buffalo Wallow field	108	48	118
Mendota field	88	35	76
All other fields	1,293	482	1,184
Total oil production	1,615	626	1,562
NGLs production (MBbls):			
Jazz Wilcox field	433	206	601
Buffalo Wallow field	581	261	618
Mendota field	437	155	327
All other fields	1,173	423	853
Total NGLs production	2,624	1,045	2,399
Natural gas production (MMcf):			
Jazz Wilcox field	5,169	2,414	7,003
Buffalo Wallow field	5,860	2,651	6,214
Mendota field	2,623	967	2,059
All other fields	15,360	4,974	11,287
Total natural gas production	29,012	11,006	26,563
Total production (MBoe):			
Jazz Wilcox field	1,420	669	1,952
Buffalo Wallow field	1,665	751	1,772
Mendota field	963	352	746
All other fields	5,026	1,734	3,918
Total production	9,074	3,506	8,388
Average production cost per equivalent Bbl [1]	$ 5.56	$ 5.27	$ 4.86

1. Excludes ad valorem taxes and gross production taxes.

Our Buffalo Wallow field in Hemphill County, Texas, contained 20% and 16% of our total proved reserves in 2021 and 2020, respectively, expressed on an oil-equivalent barrels basis. Our Mendota field, in the Granite Wash play in the Texas Panhandle, contained 15% and 16% of our total proved reserves for those same years also expressed on an oil-equivalent barrels basis. There are no other fields that accounted for over 15% of our proved reserves.

Oil, NGLs, and Natural Gas Reserves. The table below identifies our estimated proved developed and undeveloped oil, NGLs, and natural gas reserves:

	Year Ended December 31, 2021			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Total proved developed	9,019	21,525	220,640	67,317
Total proved undeveloped	—	—	—	—
Total proved	9,019	21,525	220,640	67,317

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, 2021, and comprised approximately 85% 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, 2021, we had no proved undeveloped reserves.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2021 and 2020, 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 customer accounted for 11% of our oil and natural gas revenues during the year ended December 31, 2021 and no other company accounted for over 10% of our oil and natural gas revenues besides our mid-stream segment. Our mid-stream segment purchased $48.0 million of our natural gas and NGLs production and provided gathering and transportation services of $3.3 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

CONTRACT DRILLING

General. Our contract drilling business is conducted through Unit Drilling Company. Through this company we drill onshore oil and natural gas wells for ourselves and for others. Our drilling operations are mainly in Oklahoma, Texas, and New Mexico.

The following table identifies certain information about our contract drilling segment assets and activity:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
Number of drilling rigs available for use	21	58	58
Average number of drilling rigs owned	30	58	58
Average number of drilling rigs utilized	10.9	7.2	11.5
Utilization rate [1]	36 %	12 %	20 %
Average revenue per day [2]	$ 19,097	$ 21,974	$ 26,106
Total footage drilled (feet in 1,000's)	4,487	1,062	2,999
Number of wells drilled	251	67	179

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 2021 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 maximum depth capacities of our various drilling rigs range from 9,500 to 40,000 feet allowing us to cover a wide range of our customers' drilling requirements.

The following table shows certain information about our drilling rigs as of December 31, 2021:

	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Drilling Rigs	16	5	21	20,238

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 2021 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 shows the average number of our drilling rigs working by quarter for the years indicated:

	2021	2020
First quarter	9.4	18.7
Second quarter	10.0	9.1
Third quarter	11.0	5.1
Fourth quarter	13.2	7.6

Drilling Rig Fleet. We reduced the number of drilling rigs available for use from 58 at December 31, 2020 to 21 during the second quarter of 2021 in order to focus on utilization of our BOSS drilling rigs and certain SCR rigs that are either currently under contract or candidates for future upgrades.

Dispositions. We sold non-core contract drilling assets for proceeds of $12.7 million, net of related expenses, resulting in net gains of $10.1 million during the year ended December 31, 2021.

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.

Most of our drilling contracts during 2021 and 2020 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 well-to-well 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 79% of our contract drilling revenues during the year ended December 31, 2021. 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. The contract drilling segment did not drill any wells for our oil and natural gas segment in 2021. 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.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries, of which we presently own a 50% interest. Superior's operations consist of buying, selling, gathering, processing, and treating natural gas. It operates 3 natural gas treatment plants, 12 processing plants, 18 active gathering systems, and approximately 3,822 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.

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, 2021, liquidation distributions paid first to SP Investor of $361.7 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 $361.7 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.

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 will no longer consolidate the financial position, operating results, and cash flows of Superior as of March 1, 2022. We will subsequently account for our investment in Superior as an equity method investment under the HLBV method.

The following table presents certain information regarding our mid-stream segment for the periods indicated:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
Gas gathered—Mcf/day	319,394	324,892	388,506
Gas processed—Mcf/day	130,000	135,615	158,031
NGLs sold—gallons/day	442,796	441,761	612,301

Dispositions and Acquisitions. In November 2021, we 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.

Impairment. 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.

Contracts. Our mid-stream segment provides its customers with a full range of gathering, processing, and treating services. These services are usually provided to each customer under long-term contracts (more than one year), but we also have short-term contracts. Our customer agreements include these types of contracts:

- *Fee-Based Contracts.* These contracts provide for a set fee for gathering, transporting, compressing, and treating services. Our mid-stream's revenue is a function of the volume of natural gas and is not directly dependent on the value of natural gas. For the year ended December 31, 2021, 76% of our mid-stream segment's total volumes and 73% of its operating margins (as defined below) were under fee-based contracts.
- *Commodity-Based Contracts.* These contracts consist of several contract structure types. Under these contract structures, our mid-stream segment purchases the raw well-head natural gas and settles with the producer at a stipulated price while retaining all sales proceeds from third parties or retains a negotiated percentage of the sales proceeds from the residue natural gas and NGLs it gathers and processes, with the remainder being paid to the producer. For the year ended December 31, 2021, 24% of our mid-stream segment's total volumes and 27% of operating margins (as defined below) were under commodity-based contracts.

For each of the above contract types, operating margin is defined as total operating revenues less operating expenses and does not include depreciation, amortization, and impairment, general and administrative expenses, interest expense, or income taxes.

Customers. Three customers accounted for 58% of our mid-stream revenues. We believe that there are other customers available to purchase our natural gas and NGLs if we were to lose these customers. Superior purchased $48.0 million of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $3.3 million. Intercompany revenue from services and purchases of production between Superior and our oil and natural gas segment has been eliminated in our consolidated financial statements.

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, during times of increased competition on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be intense.

Our mid-stream segment 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 in order 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 - safety and environmental stewardship are at the forefront of everything that we do.

As of March 3, 2022, we had 788 employees, none of whom are members of a union or labor organization. Our workforce includes 478 employees in our contract drilling segment, 136 employees in our oil and natural gas segment, 128 employees in our mid-stream segment, and 46 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, known as Subpart OOOOa, 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 of OOOOa 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.

Several states, including Colorado, Pennsylvania, New Mexico and Wyoming, have separately imposed their own regulations on methane emissions from the oil and natural gas sector. These regulations cover a variety of upstream and midstream sources and typically limit the venting and flaring of gas, require the installation of certain types of low-emitting equipment, and impose leak inspection and repair requirements. These and other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects, increase our costs of development and operations, and increase costs for well decommissioning and abandonment.

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 greenhouse gases (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, Oklahoma, Kansas, Colorado, and Wyoming 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, Oklahoma, and Kansas, 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, 2021, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $250 per month ($3.0 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 $130 per month ($1.6 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 $220 per month ($2.6 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 bank credit agreements. We have, and may continue to have, some indebtedness. As of December 31, 2021, we had no outstanding borrowings under the Exit credit agreement and $19.2 million of borrowings outstanding under the Superior credit agreement (as defined below).

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, 2021, we had no outstanding borrowings under our Exit credit agreement and $19.2 million outstanding under our Superior 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.

The amount Superior can borrow under its credit agreement may be affected by its cash flow.

Superior must maintain a funded debt to consolidated EBITDA ratio (as defined in the Superior credit agreement) of not greater than 4.00 to 1.00. If Superior's EBITDA falls below $50.0 million, its maximum funded debt would be limited to 4.00 times consolidated EBITDA.

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.

Changes in the method of determining LIBOR, or the replacement of LIBOR with an alternative reference rate, may hurt our indebtedness.

Our variable rate debt under both the Exit credit agreement and the Superior credit agreement is tied to LIBOR. On July 27, 2017, the Financial Conduct Authority announced that it would phase out LIBOR as a benchmark by the end of 2021. It is unclear whether new methods of calculating LIBOR will be established so that it continues to exist after 2021. There is no guarantee that a transition from LIBOR to an alternative will not cause financial market disruptions, significant increases in benchmark rates, or borrowing costs to borrowers, any of which could hurt our business, financial condition, and operations results.

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. We compete in gathering, processing, transporting, and treating natural gas with other mid-stream companies. We are continually competing with larger mid-stream companies for acquisitions and construction projects. Many of our competitors have greater financial resources, human resources, and geographic presence larger than we do.

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, 2021, we had no proved undeveloped drilling locations.

Our mid-stream operations involve many risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial, and our ability to recoup these costs is uncertain. Our operations may be curtailed, delayed, or canceled because of many things beyond our 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, 2021, one customer accounted for 11% of our oil and natural gas revenue, five customers accounted for 79% of our contract drilling revenues, and three customers accounted for 58% 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 our volumes and revenues.

We rely 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, we 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 we 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 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 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 from 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 the areas of conflict, the current conflict between Russia and Ukraine, and 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.

We could be subject to increased compliance costs related to the regulation of our pipelines.

Our 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 us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operating costs that could be significant. In addition, should we fail to comply with PHMSA or comparable state regulations, we 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 unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton and Hoxbar of Oklahoma, the Wilcox of Texas. 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, Oklahoma, Kansas, Colorado, and Wyoming, 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.

POST REORGANIZATION RISKS

Because our consolidated financial statements reflect fresh start accounting adjustments made on emergence from bankruptcy, financial information in our financial statements are not comparable to our financial information from prior periods.

With our emergence from bankruptcy on the Effective Date, we determined that the company qualified for fresh start accounting under ASC Topic 852, *Reorganizations*, under which our reorganization value, which represents the fair value of the entity before considering liabilities, is distributed to the fair value of assets in conformity with the purchase method of accounting for business combinations. We state our liabilities, other than deferred taxes, at a present value of amounts expected to be paid. Thus, our consolidated balance sheets and consolidated statements of operations are not comparable in many respects to consolidated balance sheets and consolidated statements of operations data for periods before we adopted fresh start accounting. You cannot compare information reflecting our post-emergence financial statements to information for periods before we emerged from bankruptcy without adjusting for fresh start accounting.

Even though the Plan has been consummated, we may not achieve our stated goals.

Even though the Plan has been substantially consummated, we may continue to face several risks, such as further deterioration or other changes in economic conditions, changes in our industry, changes in demand for our services, and increasing expenses. We cannot guarantee that the Plan and subsequent performance will achieve our stated goals.

Even though our debts were reduced through the Plan, we may need to raise additional funds through public or private debt or equity financing, or other various means to fund our business after completing the Chapter 11 Cases. Our access to additional financing may be limited, if available at all. Thus, adequate funds may not be available when needed or may not be available on favorable terms.

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 OTC Pink Marketplace 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 OTC Pink marketplace, the OTC Pink marketplace 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, (ii) undertaking any fundamental change to the nature of the business, or (iii) consummating a public offering of common stock.
- The board 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 or by the secretary of the company at the request of stockholders owning at least 25% of the voting stock.
- The board has the ability to authorize undesignated preferred stock. This ability makes it possible for our board 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 21 - 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

New Common Stock

After the Effective Date, we authorized 12.0 million shares of New Common Stock to be distributed under the Plan. The New Common Stock is not registered under Section 12 of the Exchange Act. On March 23, 2021, FINRA authorized a broker dealer to initiate a priced quotation of the New Common Stock on the OTC Pink Marketplace 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.

Since all of our stockholders maintain their shares in "street name" accounts and are not, individually, stockholders of record, as of March 31, 2022, there was one holder of record of our common stock.

Allocation of New Common Stock

As contemplated by the Plan, the company distributed 10,527,507 and 683,038 shares of New Common Stock to holders of the subordinated notes claims on December 11, 2020 and July 26, 2021, respectively, as well as 161,328 and 3,055 shares of New Common Stock to holders of allowed general unsecured claims on October 20, 2021 and February 23, 2022, respectively, as a result of the pro rata distribution of shares of New Common Stock out of the equity reserves established under the Plan for certain disputed claims against the company and UPC. The shares of New Common Stock were distributed pursuant to Section 1145 of the Bankruptcy Code (which generally exempts from registration under the federal and state securities laws the issuance of securities in exchange for interests in or claims against a debtor under a plan of reorganization). Pursuant to the Plan, all shares of New Common Stock were distributed in book-entry form through the facilities of The Depository Trust Company (DTC).

Common Stock Dividends

We have declared no cash dividends on our common stock. Any future determination by our board of directors to pay dividends on our common stock will be made only after considering our financial condition, results of operations, capital requirements, and other relevant factors. Under certain circumstances, none of which applied as of December 31, 2021, 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

In June 2021, we repurchased an aggregate of 600,000 shares of our common stock from the Lenders (as defined in Note 10 - Long-Term Debt And Other Long-Term Liabilities) which received these shares as an exit fee during our reorganization. The Lenders were paid $15.00 per share for their respective shares, for an aggregate cash purchase price of $9.0 million. The cash purchase price and direct acquisition costs are reflected as treasury stock on the consolidated balance sheets as of December 31, 2021.

In June 2021, our board of directors (the Board) authorized repurchasing up to $25.0 million of our outstanding common stock. In October 2021, the Board authorized an increase from $25.0 million of authorized repurchases to $50.0 million. The repurchases will be made through open market purchases, privately negotiated transactions, or other available means. We have 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, 2021, we had repurchased a total of 1,271,963 shares at an average share price of $32.57 for an aggregate purchase price of $41.4 million under the repurchase program.

During the year ended December 31, 2021, we also repurchased 78,000 shares in a privately negotiated transaction at a share price of $19.07 which were not part of the repurchase program.

The cumulative number of shares repurchased as of December 31, 2021 totaled 1,949,963, resulting in outstanding shares of 10,050,037.

The table below represents all share repurchases for the three months ended December 31, 2021:

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, 2021 through October 31, 2021	—	$ —	—	$ 40,653
November 1, 2021 through November 30, 2021	861,926	$ 34.80	861,926	$ 10,658
December 1, 2021 through December 31, 2021	60,000	$ 34.80	60,000	$ 8,570

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 our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account. We own 50% of this subsidiary.

In our oil and natural gas segment, we are optimizing production and converting non-producing reserves to producing, with selective drilling activities in core areas. 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 is expanding the Divestiture Program to now include the potential sale of additional properties, including up to all of UPC's oil and gas properties and reserves. On January 20, 2022, the company announced that it has retained a financial advisor and launched the process.

In our contract drilling segment, management reduced the number of drilling rigs available for use from 58 at December 31, 2020 to 21 during the second quarter of 2021 in order to focus on utilization of our BOSS drilling rigs and certain SCR rigs that are either currently under contract or candidates for future upgrades. Of the 21 rigs available for use, 14 are currently working, 3 are actively being marketed, and the remaining 4 will be considered for upgrade and marketing as future conditions warrant. We also plan to continue seeking opportunities to divest non-core, idle drilling equipment.

In our mid-stream segment, we are focused on continuing to generate predictable free cash flows with limited exposure to commodity prices. We also plan to continue seeking business development opportunities in our 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.

Upon our emergence from the Chapter 11 Cases on September 3, 2020, we adopted fresh start accounting as required by US GAAP. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements after August 31, 2020 are not comparable with our consolidated financial statements prior to that date.

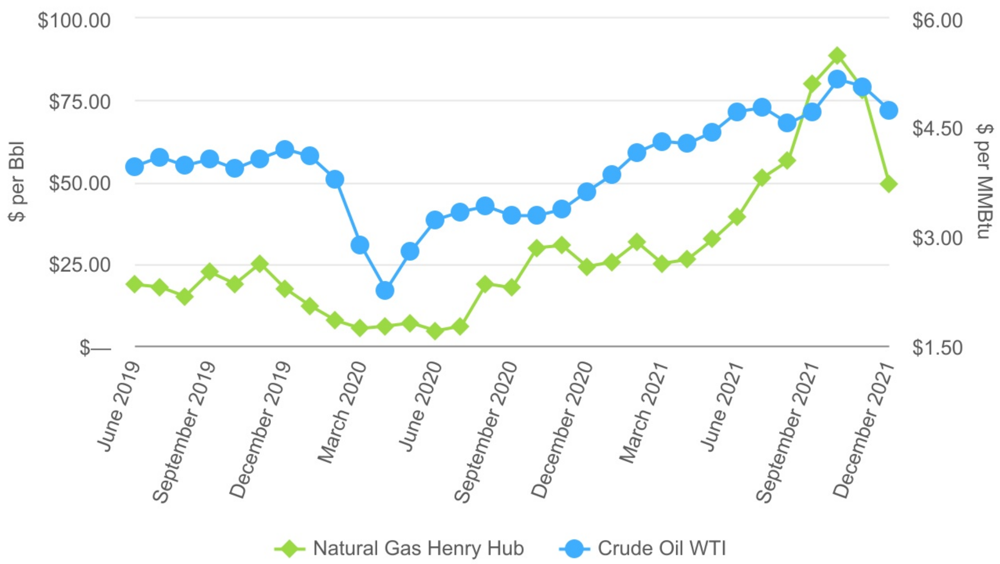
Recent Developments

Commodity Price Environment and COVID-19 Pandemic

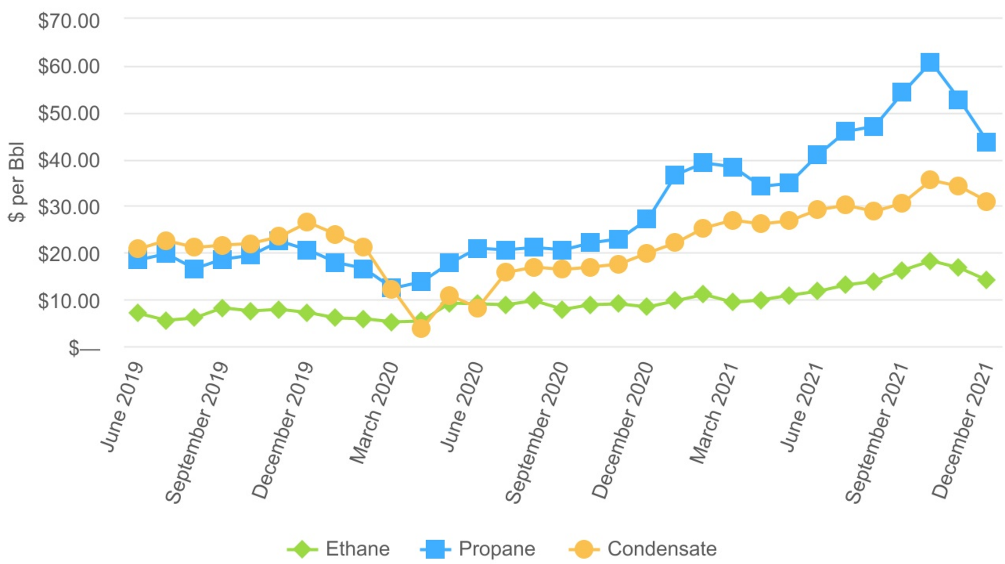
Our success depends, among other things, on prices we receive for our oil and natural gas production, the demand for oil, natural gas, and NGLs, and the demand for our drilling rigs which influences the amounts we can charge for those drilling rigs. While our operations are all within the United States, events outside the United States affect us and our industry, including political and economic uncertainty and geopolitical activity.

We are continuously monitoring the current and potential impacts of the COVID-19 pandemic, including any new variants, on our business. This includes how it has and may continue to impact our operations, financial results, liquidity, customers, employees, and vendors as new COVID-19 variants may have undetermined impacts to our business. In response to the pandemic, we have implemented various measures to ensure we are conducting our business in a safe and secure manner.

During the last two years commodity prices have been volatile, 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. NGLs prices reflect a weighted-average, based on production, of Mont Belvieu and Conway prices.

Stock Repurchase Activity

In June 2021, we repurchased an aggregate of 600,000 shares of our common stock from the Lenders (as defined in Note 10 - Long-Term Debt And Other Long-Term Liabilities) which received these shares as an exit fee during our reorganization. The Lenders were paid $15.00 per share for their respective shares, for an aggregate cash purchase price of $9.0 million.

In June 2021, our board of directors (the Board) authorized repurchasing up to $25.0 million of our outstanding common stock. In October 2021, the Board authorized an increase from $25.0 million of authorized repurchases to $50.0 million. The repurchases will be made through open market purchases, privately negotiated transactions, or other available means. We have 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, 2021, we had repurchased a total of 1,271,963 shares at an average share price of $32.57 for an aggregate purchase price of $41.4 million under the repurchase program.

During the year ended December 31, 2021, we also repurchased 78,000 shares in a privately negotiated transaction at a share price of $19.07 which were not part of the repurchase program.

The cumulative number of shares repurchased as of December 31, 2021 totaled 1,949,963, resulting in outstanding shares of 10,050,037.

Warrants

Each holder of the Old Common Stock outstanding before the Effective 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 will initially be exercisable for one share of New Common Stock, subject to adjustment as provided in the Warrant Agreement. The exercise price of the Warrants will be determined, and the Warrants will become exercisable, once the Debtors have completed the claims reconciliation process and resolved any objections to disputed claims under the Bankruptcy Petitions. The initial exercise price per share for the Warrants will be set at an amount that implies a recovery by holders of the Subordinated Notes of the $650 million principal amount of the Subordinated Notes plus interest thereon to the May 15, 2021 maturity date of the Notes. 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, dissolutions or winding up of the company (such earliest date, the Expiration Date). Each Warrant that is not exercised on or before the Expiration Date will expire, and all rights under that Warrant and the Warrant Agreement will cease on the Expiration Date.

The warrants issued to holders of the company’s Old Common Stock that did not opt-out of the releases under the Plan and that owned their shares of old common stock through Direct Registration are outlined below:

Issuance Date	Warrants Issued
December 21, 2020	1,764,164
February 11, 2021	42,511
July 29, 2021	10,521
October 13, 2021	5,005
Total	1,822,201

The company expects to issue approximately 21,117 more Warrants to the holders of the Old Common Stock that did not opt-out of the releases under the Plan and owned their shares through Direct Registration.

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. 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 will no longer consolidate the financial position, operating results, and cash flows of Superior as of March 1, 2022. We will subsequently account for our investment in Superior as an equity method investment under the HLBV method.

Critical Accounting Policies and Estimates

Summary

In this section, we identify those critical accounting policies we follow in preparing our financial statements and related disclosures. Many 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. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our reserves. That audit as of December 31, 2021 covered those reserves we projected to comprise 85% of the total proved developed future net income discounted at 10% (based on the SEC's unescalated pricing policy). Included in Part I, Item 1 of this report are the qualifications of our independent petroleum engineering firm and our employees responsible for preparing our reserve reports.

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. At December 31, 2021, our reserves were calculated based on applying 12-month 2021 average unescalated prices of $66.56 per barrel of oil, $44.22 per barrel of NGLs, and $3.60 per Mcf of natural gas (then adjusted for price differentials) over the estimated life of each of our oil and natural gas properties.

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.

Warrant Liability. We recognize 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. The liability will continue to be adjusted to fair value at each reporting period until the warrants meet the definition of an equity instrument, at which time they will be reported as shareholders' equity and no longer subject to future fair value adjustments.

Bankruptcy Reorganization. We have applied Accounting Standards Codification (ASC) 852, Reorganizations (ASC 852) in preparing our consolidated financial statements. ASC 852 requires that the financial statements, for periods subsequent to the Chapter 11 Cases, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, realized gains and losses and provisions for losses that are realized or incurred in the bankruptcy proceedings, are recorded in reorganization items, net on our accompanying consolidated statements of operations.

Fresh Start. The company qualified for and adopted fresh start accounting under the provisions of ASC 852. When applying ASC 852, an entity determines its reorganization value and enterprise value. Reorganization value, as determined under ASC 820, *Fair Value Measurement*, represents the fair value of the entity's total assets before the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The entity's enterprise value represents the estimated fair value of an entity’s long-term debt and equity. The assumptions used in estimating these values are inherently uncertain and require significant judgment.

Recently Issued Accounting Standards

Reference Rate Reform (Topic 848)—Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The FASB issued ASU 2020-04 and ASU 2021-01 which provide and clarify optional expedients and exceptions for applying generally accepted accounting principles to contract modifications, subject to meeting certain criteria, that reference LIBOR or another reference rate expected to be discontinued. The amendments within these ASUs will be in effect for a limited time beginning March 12, 2020, and an entity may elect to apply the amendments prospectively through December 31, 2022. We have not yet elected to use the optional guidance and continue to evaluate the options provided by ASU 2020-04 and ASU 2021-01.

Debt—Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging— Contracts in Entity’s Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity’s Own Equity. The FASB issued ASU 2020-06 which simplifies the accounting for convertible instruments by removing certain accounting models which separate the embedded conversion features from the host contract for convertible instruments. The ASU further removes certain settlement conditions that are required for equity contracts to qualify for the derivative scope exception and simplifies the diluted earnings per share calculation in certain areas. The ASU is effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. We will adopt ASU 2020-06 effective January 1, 2022. The adoption of this ASU is not expected to have a material impact on our consolidated financial statements.

Recently Adopted Accounting Standards

Income Taxes (Topic 740)—Simplifying the Accounting for Income Taxes. The FASB issued ASU 2019-12 to simplify the accounting for income taxes by removing certain exceptions to the general principles in Topic 740. The amendments also improve consistent application of and simplify GAAP for other areas of Topic 740 by clarifying and amending existing guidance. The amendment is effective for reporting periods beginning after December 15, 2020. The adoption of this standard did not have a material impact to our consolidated financial statements.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity primarily depend on the cash flow from our operations and borrowings under our credit agreements. The principal factors determining our cash flow are:

- the amount of natural gas, oil, and NGLs we produce;
- the prices we receive for our natural gas, oil, and NGLs production;
- the use 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 the Exit credit agreement and the Superior credit agreement are adequate to cover our liquidity requirements for at least the next 12 months.

Below is a summary of certain financial information for the periods indicated:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
Net cash provided by operating activities	$ 175,969	$ 29,807	$ 44,956
Net cash provided by (used in) investing activities	36,205	(2,258)	(20,139)
Net cash provided by (used in) financing activities	(160,748)	(47,775)	7,552
Net increase (decrease) cash, restricted cash, and cash equivalents	$ 51,426	$ (20,226)	$ 32,369

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 oil, NGL, and natural gas we produce, settlements of derivative contracts, third-party use for our drilling rigs and mid-stream services, and the rates we can charge for those 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, 2021 increased by $101.2 million as compared to the year ended December 31, 2020 primarily due to increased operating profit in all three segments partially offset by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

We have historically dedicated a substantial portion of our capital budgets to our exploration for and production of oil, NGLs, and natural gas. These expenditures are necessary to off-set the inherent production declines typically experienced in oil and gas wells. Although we have curtailed our spending throughout 2020 and into 2021, we expect the majority of future capital budgets to be focused on low cost capital projects to enhance production and reserves in this favorable price environment.

Net cash provided by (used in) investing activities increased by $58.6 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to proceeds received from the disposition of our corporate headquarters building and land, an increase in proceeds received from the disposition of other non-core assets, and a decrease in capital expenditures resulting from a decrease in the number of wells drilled and oil and gas property acquisitions, partially offset by the Superior gathering system acquisition.

Cash Flows from Financing Activities

Net cash provided by (used in) financing activities decreased by $120.5 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to higher payments on our credit agreements, the repurchase of common stock, lower borrowings under our credit agreements, distributions made to non-controlling interests, and lower bank overdrafts.

As of December 31, 2021, we had unrestricted cash and cash equivalents totaling $64.1 million, which includes $17.2 million of cash and cash equivalents held by Superior, and $19.2 million of outstanding borrowings, all of which was borrowed under the Superior credit agreement. Unit had no outstanding borrowings under the Exit credit agreement.

Below, we summarize certain financial information as of December 31:

	Successor 2021	Successor 2020
	(In thousands)	
Working capital	$ 5,792	$ 2,575
Current portion of long-term debt	$ —	$ 600
Long-term debt [(1)]	$ 19,200	$ 98,400
Shareholders' equity attributable to Unit Corporation	$ 187,397	$ 179,222

Working Capital

Typically, our working capital balance fluctuates, in part, because of 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 derivative activity. We had positive working capital of $5.8 million at December 31, 2021 compared to positive working capital of $2.6 million as of December 31, 2020. The increase in working capital is primarily due to higher cash and cash equivalents and accounts receivable, partially offset by higher current derivative liabilities, warrant liability, and accounts payable. Both the Superior credit agreement and the Exit credit agreement may be used for working capital. As of December 31, 2021, we had no outstanding borrowings under the Exit credit agreement and $19.2 million of outstanding borrowings under the Superior credit agreement. The effect of our derivatives decreased working capital by $40.9 million as of December 31, 2021 and decreased working capital by $1.0 million as of December 31, 2020.

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.

During the year ended December 31, 2021, the company repaid $145.1 million of borrowings under the Exit credit agreement with cash generated from operations as well as from proceeds from divestitures of non-core assets. As of December 31, 2021, we had no outstanding long-term borrowings under the Exit credit agreement.

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). The maturity date of borrowings under the Superior credit agreement is March 10, 2023. As of December 31, 2021, we had $19.2 million of borrowings and $0.5 million of letters of credit outstanding under the Superior credit agreement.

Capital Requirements

Oil and Natural Gas Segment Dispositions, Acquisitions, and Capital Expenditures. 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.

Capital expenditures for oil and gas properties on the full cost method for the year ended December 31, 2021 by this segment, excluding a $0.5 million increase in the ARO liability, totaled $17.3 million. Capital expenditures for the four months ended December 31, 2020, excluding a $1.7 million reduction in the ARO liability, totaled $4.0 million while capital expenditures for the eight months ended August 31, 2020, excluding a $29.2 million reduction in the ARO liability and $0.4 million for acquisitions (including associated ARO), totaled $5.4 million. We participated in the completion of 12 gross wells (1.75 net wells) drilled by other operators during the year ended December 31, 2021 compared to 3 gross wells (0.30 net wells) drilled by other operators in which we participated during the four months ended December 31, 2020 and 16 gross wells (0.35 net wells) drilled by other operators in which we participated during the eight months ended August 31, 2020.

On June 25, 2021, the company entered into a purchase and sale agreement to which we agreed to sell substantially all of our wells and the leases related thereto located near Oklahoma City, Oklahoma for $19.5 million, subject to customary closing and post-closing adjustments. The divestiture closed on August 16, 2021, with an effective date of May 1, 2021. The sale of these assets did not result in a significant alteration of the full cost pool, and therefore no gain or loss was recognized.

On March 30, 2021, the company entered into a purchase and sale agreement to which we agreed to sell substantially all of our wells and the leases related thereto located in Reno and Stafford Counties, Kansas for $7.1 million, subject to customary closing and post-closing adjustments. This divestiture closed on May 6, 2021, with an effective date of February 1, 2021. The sale of these assets did not result in a significant alteration of the full cost pool and therefore, no gain or loss was recognized.

We also sold $5.0 million of other non-core oil and natural gas assets, net of related expenses, during the year ended December 31, 2021, compared to $0.4 million during the four months ended December 31, 2020, and $1.2 million during the eight months ended August 31, 2020. No gain or loss was recognized as the sale of these assets did not result in a significant alteration of the full cost pool.

*Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. C*apital expenditures for 2021 were primarily related to maintenance capital on operating drilling rigs. We also pursued the disposal or sale of our non-core, idle drilling rig fleet. We incurred $2.9 million in capital expenditures during the year ended December 31, 2021 compared to $0.6 million and $2.4 million during the four months ended December 31, 2020 and eight months ended August 31, 2020, respectively.

We sold non-core contract drilling assets for proceeds of $12.7 million, net of related expenses, during the year ended December 31, 2021, compared to $1.3 million during the four months ended December 31, 2020, and $4.8 million during the eight months ended August 31, 2020. These proceeds resulted in net gains of $10.1 million during the year ended December 31, 2021, compared to $0.5 million during the four months ended December 31, 2020, and $1.4 million during the eight months ended August 31, 2020.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. During the year ended December 31, 2021, our mid-stream segment incurred $24.5 million in capital expenditures (including the $13.0 million acquisition of a gathering and processing system in southern Kansas) compared to $1.3 million and $9.3 million during the four months ended December 31, 2020 and eight months ended August 31, 2020, respectively.

Contractual Commitments

We had the following contractual commitments as of December 31, 2021:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Long-term debt [1]	$ 19,200	$ —	$ 19,200	$ —	$ —
Operating leases [2]	14,001	4,382	6,004	3,565	50
Firm transportation commitments [3]	880	880	—	—	—
Total contractual obligations	$ 34,081	$ 5,262	$ 25,204	$ 3,565	$ 50

1. Represents outstanding borrowings as of December 31, 2021 under the Superior credit agreement with a maturity date of May 10, 2023. Unit's Exit credit agreement has a maturity date of March 1, 2024, but no outstanding balance as of December 31, 2021.
2. Represents payments related to the noncancellable terms of certain leases for office space, land, and equipment, including pipeline equipment and office equipment capitalized on the consolidated balance sheets as of December 31, 2021.
3. Represent firm transportation commitments to transport our natural gas from various systems.

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, 2021, based on our fourth quarter 2021 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	2022	2023
Daily oil production	53%	24%
Daily natural gas production	50%	28%

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, 2021 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 $58.7 million as of December 31, 2021.

Warrants

We recognize 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. The liability will continue to be adjusted to fair value at each reporting period until the warrants meet the definition of an equity instrument, at which time they will be reported as shareholders' equity and 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:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
		(In thousands)	
Loss on derivatives	$ (97,615)	$ (985)	$ (10,704)
Cash settlements paid on commodity derivatives	(44,591)	(1,133)	(4,244)
Loss on derivatives less cash settlements paid on commodity derivatives	$ (53,025)	$ 148	$ (6,460)
Loss on change in fair value of warrants	$ (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 $40.9 million and long-term derivative liabilities of $17.9 million as of December 31, 2021 compared to current derivative liabilities of $1.0 million and non-current derivative liabilities of $4.7 million as of December 31, 2020.

Stock-Based Compensation

We granted 315,529 restricted stock units (RSU) 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. We did not capitalize any compensation cost to oil and natural gas properties due to the absence of significant drilling.

We did not grant any new awards during the four months ended December 31, 2020 or the eight months ended August 31, 2020. On the Effective Date, all equity-based awards that were outstanding immediately before the Effective Date were cancelled. The cancellation of the awards resulted in an acceleration of unrecorded stock compensation expense during the eight months ended August 31, 2020. We recognized compensation expense of $6.1 million for all our prior restricted stock awards including the acceleration of the unrecorded stock compensation expense. We did not capitalize any compensation cost to oil and natural gas properties due to the absence of significant drilling.

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, 2021 versus Year Ended December 31, 2020

Provided below is a comparison of selected operating and financial data (in thousands unless otherwise specified):

	Successor	Successor	Predecessor	
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020	Percent Change [(1)]
Total revenue, before eliminations	$ 690,012	$ 145,362	$ 291,493	58 %
Total revenue, after eliminations	$ 638,716	$ 133,528	$ 276,957	56 %
Net income (loss)	$ 48,216	$ (13,988)	$ (890,624)	105 %
Net income (loss) attributable to non-controlling interest	$ (12,431)	$ 4,152	$ 40,388	(128) %
Net income (loss) attributable to Unit Corporation	$ 60,647	$ (18,140)	$ (931,012)	106 %
Oil and Natural Gas:				
Revenue, before eliminations	$ 272,231	$ 57,580	$ 103,443	69 %
Operating costs, before eliminations	$ 83,221	$ 26,111	$ 119,664	(43) %
Average oil price (Bbl)	$ 50.03	$ 37.29	$ 31.98	49 %
Average oil price excluding derivatives (Bbl)	$ 66.50	$ 39.23	$ 35.14	83 %
Average NGLs price (Bbl)	$ 23.41	$ 9.28	$ 4.83	NM
Average NGLs price excluding derivatives (Bbls)	$ 23.41	$ 9.28	$ 4.83	NM
Average natural gas price (Mcf)	$ 2.93	$ 1.92	$ 1.14	114 %
Average natural gas price excluding derivatives (Mcf)	$ 3.55	$ 1.91	$ 1.11	163 %
Oil production (MBbls)	1,615	626	1,562	(26) %
NGLs production (MBbls)	2,624	1,045	2,399	(24) %
Natural gas production (MMcf)	29,012	11,006	26,561	(23) %
Contract Drilling:				
Revenue, before eliminations	$ 76,107	$ 19,413	$ 73,519	(18) %
Operating costs, before eliminations	$ 60,973	$ 13,852	$ 51,810	(7) %
Average number of drilling rigs in use	10.9	7.2	11.5	8 %
Total drilling rigs available for use at the end of the period	21	58	58	(64) %
Average dayrate on daywork contracts	$ 17,987	$ 17,807	$ 18,911	(4) %
Mid-Stream:				
Revenue, before eliminations	$ 341,674	$ 68,369	$ 114,531	87 %
Operating costs, before eliminations	$ 286,199	$ 53,147	$ 80,607	114 %
Gas gathered--Mcf/day	319,394	324,892	388,506	(13) %
Gas processed--Mcf/day	130,000	135,615	158,031	(14) %
Gas liquids sold--gallons/day	442,796	441,761	612,301	(20) %
Number of natural gas gathering systems	18	17	18	6 %
Number of processing plants	12	11	11	9 %
Corporate and Other:				
General and administrative expense, before eliminations	$ 21,399	$ 6,702	$ 42,766	(57) %
Interest expense, net	$ (4,266)	$ (3,275)	$ (22,882)	(84) %
Write-off of debt issuance costs	$ —	$ —	$ (2,426)	(100) %
Reorganization items, net	$ (4,294)	$ (2,273)	$ 133,975	(103) %
Loss on derivatives	$ (97,615)	$ (985)	$ (10,704)	NM
Loss on change in fair value of warrants	$ (18,937)	$ —	$ —	— %
Income tax (benefit) expense	$ 173	$ (302)	$ (14,630)	101 %
Average interest rate	6.4 %	6.8 %	5.5 %	14 %
Average long-term debt outstanding	$ 46,222	$ 121,740	$ 526,167	(88) %

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

Oil and Natural Gas

Oil and natural gas revenues increased $111.2 million or 69% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to higher commodity prices partially offset by lower production volumes. The decrease in volumes was 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 decreased $62.6 million or 43% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to the absence of gains recognized on the settlement of Predecessor Period liabilities subject to compromise under the Plan offset by increased production tax expenses due to increased revenues.

Impairment of oil and natural gas properties decreased $419.8 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 due to the absence of the ceiling test write-downs and salt water disposal asset impairment recorded during the year ended December 31, 2020.

Depreciation, depletion, and amortization of oil and natural gas properties decreased $59.0 million or 71% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to a lower depreciable base subsequent to fresh start accounting and lower average production.

Contract Drilling

Contract drilling revenues decreased $16.8 million or 18% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to lower rig termination and standby fees of $0.1 million in 2021 compared to $18.5 million in 2020. Additionally, there was an 8% increase in the average number of drilling rigs in use and a 4% decrease in the average dayrate. Average drilling rig utilization increased from 10.1 drilling rigs in the year ended December 31, 2020 to 10.9 drilling rigs in the year ended December 31, 2021.

Contract drilling operating costs decreased 4.7 million or 7% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to the reduced number of drilling rigs operating.

Impairment of contract drilling equipment decreased $410.1 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 due to the absence of impairments of SCR drilling rigs and other equipment recorded during the year ended December 31, 2020.

Depreciation of contract drilling equipment decreased $11.3 million or 64% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to fewer rigs available for use and a lower depreciable base subsequent to fresh start accounting, partially offset by higher average drilling rig utilization.

Mid-Stream

Mid-Stream revenues increased $158.8 million or 87% during the year ended December 31 2021 compared to the year ended December 31, 2020 primarily due to higher prices, partially offset by lower volumes. Gas processed volumes per day decreased 14% between the comparative periods primarily due to declining volumes and fewer new wells connected to our processing systems. Gas gathered volumes per day decreased 13% between the comparative periods also due to declining volumes and fewer new wells connected to our gathering systems. We also experienced overall lower volumes due to the February 2021 winter storm.

Operating costs increased $152.4 million or 114% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to higher gas, NGLs, and condensate prices, partially offset by lower purchase volumes.

Impairment of mid-stream assets decreased $53.3 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to the absence of $64.0 million of impairment of certain assets in southern Kansas and central Oklahoma recorded during the year ended December 31, 2020, partially offset by $10.7 million of impairment to a gathering system in Pennsylvania during the year ended December 31, 2021.

Depreciation of mid-stream assets decreased $7.5 million or 19% primarily due to a lower depreciable base subsequent to fresh start accounting.

General and Administrative

General and administrative expenses decreased $28.1 million or 57% during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to lower headcount, the absence of separation benefits recognized during 2020 as well as lower legal spend.

Interest, net

Interest expense decreased $21.9 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to a reduction in average long-term debt outstanding, partially offset by a higher average interest rate. Our average long-term debt outstanding decreased $345.1 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to the Notes being settled in conjunction with the Plan as well as subsequent payments made under the Exit credit agreement while our average interest rate increased from 5.6% during the year ended December 31, 2020 to 6.4% during the year ended December 31, 2021.

Write-off of Debt Issuance Costs

Unamortized debt issuance costs of $2.4 million were written off during the year ended December 31, 2020 due to the termination of the remaining commitments of the Predecessor Period Unit credit agreement.

Reorganization Items, Net

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

Loss on Derivatives

Loss on derivatives increased by $85.9 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to increases in commodity market pricing.

Loss on Change in Fair Value of Warrants

Loss on change in fair value of warrants increased by $18.9 million during the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to increases in Unit's share price as well as higher volatility assumptions, partially offset by lower duration to exercise given the passage of time.

Income Tax

Income tax expense was $0.2 million during the year ended December 31, 2021 compared to an income tax benefit of $14.9 million during the year ended December 31, 2020 primarily due to the absence of the losses generated during the year ended December 31, 2020 and the full valuation allowance against our net deferred tax asset.

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. Increases in these 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 2021 production, a $0.10 per Mcf change in what we are paid for our natural gas production would cause a corresponding $250 per month ($3.0 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $130 per month ($1.6 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $220 per month ($2.6 million annualized) change in our pre-tax 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, 2021, these non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'22 - Dec'22	Natural gas - swap	5,000 MMBtu/day	$2.605	IF - NYMEX (HH)
Jan'23 - Dec'23	Natural gas - swap	22,000 MMBtu/day	$2.456	IF - NYMEX (HH)
Jan'22 - Dec'22	Natural gas - collar	35,000 MMBtu/day	$2.50 - $2.68	IF - NYMEX (HH)
Jan'22 - Jun'22	Crude oil - swap	986 Bbl/day	$70.3	WTI - NYMEX
Jan'22 - Dec'22	Crude oil - swap	2,300 Bbl/day	$42.25	WTI - NYMEX
Jan'23 - Dec'23	Crude oil - swap	1,300 Bbl/day	$43.60	WTI - NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreements. Borrowings under our Exit credit agreement and Superior credit agreement bear interest at variable interest rates. Based on our average outstanding long-term debt subject to a variable rate in 2021, a 1% increase in the interest rate on the outstanding borrowings under these facilities would reduce our annual pre-tax cash flow by approximately $0.5 million.

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, 2021 and 2020 (Successor), the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity, and cash flows for the year ended December 31, 2021 and the period from September 1, 2020 to December 31, 2020 (Successor) and for the period from January 1, 2020 to August 31, 2020 (Predecessor), 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, 2021 and 2020, and the results of its operations and its cash flows for the year ended December 31, 2021 and for the periods from September 1, 2020 to December 31, 2020 (Successor) and from January 1, 2020 to August 31, 2020 (Predecessor), in conformity with accounting principles generally accepted in the United States of America.

Basis of presentation

As discussed in Note 2 to the financial statements, the United States Bankruptcy Court for the District of Delaware entered an order confirming the plan for reorganization on August 6, 2020, and the Company emerged from bankruptcy on September 3, 2020. Accordingly, the accompanying financial statements have been prepared in conformity with FASB Accounting Standards Codification 852, Reorganizations, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods, as described in Note 25.

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 the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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 a critical audit matter 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 matters 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 and proved property impairment — oil and natural gas reserve quantities and future cash flows

As described further in Note 3 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 and to determine if any full cost ceiling impairment exists for its oil and natural gas properties, and if applicable, record impairment. 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 and impairment 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 and potential impairment of oil and natural gas properties.

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 or impairment 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 third-party 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 and impairment calculations that included these proved reserves.
- We evaluated certain 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, 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 31, 2022

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Successor December 31, 2021	Successor December 31, 2020
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 64,140	$ 12,145
Restricted cash	—	569
Accounts receivable, net of allowance for credit losses of $2,511 and $3,783 at December 31, 2021 and December 31, 2020, respectively	87,248	57,846
Current income taxes receivable	—	1,150
Prepaid expenses and other	5,542	11,212
Total current assets	156,930	82,922
Property and equipment:		
Oil and natural gas properties, on the full cost method:		
Proved properties	225,014	238,581
Unproved properties not being amortized	422	1,591
Drilling equipment	66,058	63,687
Gas gathering and processing equipment	274,748	251,404
Corporate land and building	—	32,635
Transportation equipment	4,550	3,130
Other	8,631	9,961
	579,423	600,989
Less accumulated depreciation, depletion, amortization, and impairment	128,880	54,189
Net property and equipment	450,543	546,800
Right of use asset (Note 19)	12,445	5,592
Other assets	9,559	14,389
Total assets [(1)]	$ 629,477	$ 649,703

1. Unit Corporation's consolidated total assets as of December 31, 2021 include current and long-term assets of its variable interest entity (VIE) (Superior) of $61.1 million and $229.5 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated cash and cash equivalents of $64.1 million as of December 31, 2021 includes $17.2 million held by Superior. Unit Corporation's consolidated total assets as of December 31, 2020 include current and long-term assets of its variable interest entity (VIE) (Superior) of $45.8 million and $247.8 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated cash and cash equivalents of $12.1 million as of December 31, 2020 includes $11.6 million held by Superior.

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (Continued)

		Successor December 31, 2021		Successor December 31, 2020
		(In thousands except share and par value amounts)		
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	58,625	$	40,829
Accrued liabilities (Note 9)		22,450		21,743
Current operating lease liability (Note 19)		3,791		4,075
Current portion of long-term debt (Note 10)		—		600
Current derivative liabilities (Note 17)		40,876		1,047
Warrant liability (Note 17)		19,822		885
Current portion of other long-term liabilities (Note 10)		5,574		11,168
Total current liabilities		151,138		80,347
Long-term debt (Note 10)		19,200		98,400
Non-current derivative liabilities (Note 17)		17,855		4,659
Operating lease liability (Note 19)		8,677		1,445
Other long-term liabilities (Note 10)		32,939		39,259
Deferred income taxes (Note 13)		—		—
Commitments and contingencies (Note 21)				
Shareholders' equity:				
Common stock, $0.01 par value, 25,000,000 shares authorized, 12,000,000 shares issued and 10,050,037 outstanding as of December 31, 2021, and 12,000,000 issued and outstanding as of December 31, 2020		120		120
Treasury stock		(51,965)		—
Capital in excess of par value		198,171		197,242
Retained earnings (deficit)		41,071		(18,140)
Total shareholders' equity attributable to Unit Corporation		187,397		179,222
Non-controlling interests in consolidated subsidiaries		212,271		246,371
Total shareholders' equity		399,668		425,593
Total liabilities and shareholders' equity [1]	$	629,477	$	649,703

1. Unit Corporation's consolidated total liabilities as of December 31, 2021 include current and long-term liabilities of Superior of $42.3 million and $21.2 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. All of Unit Corporation's consolidated long-term debt of $19.2 million as of December 31, 2021 was held by Superior. Unit Corporation's consolidated total liabilities as of December 31, 2020 include current and long-term liabilities of the VIE of $28.4 million and $2.6 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. None of Unit Corporation's consolidated long-term debt of $98.4 million as of December 31, 2020 was held by Superior.

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands except per share amounts)		
Revenues:			
Oil and natural gas	$ 224,232	$ 57,578	$ 103,439
Contract drilling	76,107	19,413	73,519
Gas gathering and processing	338,377	56,537	99,999
Total revenues	638,716	133,528	276,957
Expenses:			
Operating costs:			
Oil and natural gas	79,924	25,256	117,691
Contract drilling	60,973	13,852	51,810
Gas gathering and processing	234,684	42,169	68,045
Total operating costs	375,581	81,277	237,546
Depreciation, depletion, and amortization	64,326	27,962	115,496
Impairments (Note 4)	10,673	26,063	867,814
Loss on abandonment of assets (Note 4)	—	—	18,733
General and administrative	24,915	6,702	42,766
Gain on disposition of assets	(10,877)	(619)	(89)
Total operating expenses	464,618	141,385	1,282,266
Income from operations	174,098	(7,857)	(1,005,309)
Other income (expense):			
Interest, net	(4,266)	(3,275)	(22,824)
Write-off debt issuance costs	—	—	(2,426)
Gain (loss) on derivatives (Note 17)	(97,615)	(985)	(10,704)
Loss on change in fair value of warrants (Note 17)	(18,937)	—	—
Reorganization items, net (Note 25)	(4,294)	(2,273)	133,975
Other, net	(597)	100	2,034
Total other income (expense)	(125,709)	(6,433)	100,055
Income (loss) before income taxes	48,389	(14,290)	(905,254)
Income tax expense (benefit):			
Current	173	(302)	(917)
Deferred	—	—	(13,713)
Total income taxes	173	(302)	(14,630)
Net income (loss)	48,216	(13,988)	(890,624)
Net income (loss) attributable to non-controlling interest	(12,431)	4,152	40,388
Net income (loss) attributable to Unit Corporation	$ 60,647	$ (18,140)	$ (931,012)
Net income (loss) attributable to Unit Corporation per common share (Note 8):			
Basic	$ 5.32	$ (1.51)	$ (17.45)
Diluted	$ 5.26	$ (1.51)	$ (17.45)

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
Net income (loss)	$ 48,216	$ (13,988)	$ (890,624)
Other comprehensive income (loss), net of taxes:			
Reclassification adjustment for write-down of securities	—	—	—
Comprehensive income (loss)	48,216	(13,988)	(890,624)
Less: Comprehensive income (loss) attributable to non-controlling interest	(12,431)	4,152	40,388
Comprehensive income (loss) attributable to Unit Corporation	$ 60,647	$ (18,140)	$ (931,012)

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, 2019 (Predecessor)	10,591	—	644,152	199,135	201,757	1,055,635
Net income (loss)	—	—	—	(931,012)	40,388	(890,624)
Activity in stock-based compensation plans	113	—	6,001	—	55	6,169
Balances, August 31, 2020 (Predecessor)	10,704	—	650,153	(731,877)	242,200	171,180
Cancellation of Predecessor equity	(10,704)	—	(650,153)	731,877	—	71,020
Issuance of Successor equity	120	—	197,203	—	—	197,323
Balances, September 1, 2020 (Successor)	120	—	197,203	—	242,200	439,523
Net income (loss)	—	—	—	(18,140)	4,152	(13,988)
Activity in stock-based compensation plans	—	—	39	—	19	58
Balances, December 31, 2020 (Successor)	120	—	197,242	(18,140)	246,371	425,593
Net income (loss)				60,647	(12,431)	48,216
Activity in stock-based compensation plans	—	—	929	—	31	960
Distributions to non-controlling interests	—	—	—	—	(23,136)	(23,136)
Balance correction (Note 3)	—	—	—	(1,436)	1,436	—
Repurchases of common stock	—	(51,965)	—	—	—	(51,965)
Balances, December 31, 2021 (Successor)	$ 120	$ (51,965)	$ 198,171	$ 41,071	$ 212,271	$ 399,668

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
OPERATING ACTIVITIES:			
Net income (loss)	$ 48,216	$ (13,988)	$ (890,624)
Adjustments to reconcile net income operating activities:			
Depreciation, depletion, and amortization	64,326	27,962	115,496
Impairments (Note 4)	10,673	26,063	867,814
Loss on abandonment of assets (Note 4)	—	—	18,733
Amortization of debt issuance costs and debt discount (Note 10)	—	—	1,079
Loss on derivatives (Note 17)	97,615	985	10,704
Cash receipts (payments) on derivatives settled (Note 17)	(44,591)	(1,133)	(4,244)
Loss on change in fair value of warrants (Note 17)	18,937	—	—
Gain on disposition of assets	(10,877)	(619)	(89)
Write-off of debt issuance costs	—	—	2,426
Deferred tax expense (Note 13)	—	—	(13,713)
Stock-based compensation plans	929	58	4,786
Credit loss expense	1,633	—	3,155
ARO liability accretion (Note 11)	1,893	467	1,545
Contract assets and liabilities, net (Note 5)	3,699	1,316	2,459
Capitalized contract fulfillment costs, net	(537)	—	—
Noncash reorganization items	10	67	(138,797)
Other, net	(843)	(3,046)	12,164
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(31,034)	(7,226)	28,880
Materials and supplies	—	—	89
Prepaid expenses and other	(4,953)	1,795	(3,849)
Accounts payable	23,141	1,484	(18,381)
Accrued liabilities	(3,331)	(4,048)	44,811
Income taxes	1,160	(301)	906
Contract advances	(97)	(29)	(394)
Net cash provided by operating activities	175,969	29,807	44,956
INVESTING ACTIVITIES:			
Capital expenditures	(30,305)	(4,057)	(25,775)
Producing property and other oil and natural gas acquisitions	—	—	(382)
Other acquisitions	(13,000)	—	—
Proceeds from disposition of property and equipment	79,510	1,799	6,018
Net cash provided by (used in) investing activities	$ 36,205	$ (2,258)	$ (20,139)

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

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
FINANCING ACTIVITIES:			
Borrowings under line of credit, including borrowings under DIP credit facility	$ 65,300	$ —	$ 87,400
Payments under line of credit	(145,100)	(49,000)	(64,100)
DIP financing costs	—	—	(990)
Exit facility financing costs	—	—	(3,225)
Net payments on finance leases	(3,216)	(1,406)	(2,757)
Employee taxes paid by withholding shares	—	—	(43)
Distributions to non-controlling interest	(23,136)	—	—
Repurchase of common stock	(51,965)	—	—
Bank overdrafts (Note 3)	(2,631)	2,631	(8,733)
Net cash provided by (used in) financing activities	(160,748)	(47,775)	7,552
Net increase (decrease) in cash, restricted cash, and cash equivalents	51,426	(20,226)	32,369
Cash, restricted cash, and cash equivalents, beginning of period	12,714	32,940	571
Cash, restricted cash, and cash equivalents, end of period	$ 64,140	$ 12,714	$ 32,940
Supplemental disclosure of cash flow information:			
Cash paid for:			
Interest paid (net of capitalized)	$ 4,769	$ 2,571	$ 6,417
Income taxes	$ —	$ —	$ —
Reorganization items	$ 4,283	$ 2,206	$ 4,822
Changes in accounts payable and accrued liabilities related to purchases of property and equipment	$ (1,249)	$ 1,902	$ 8,561
Non-cash reductions (increases) to oil and natural gas properties related to asset retirement obligations	$ (478)	$ 1,702	$ 29,189
Non-cash trade of property and equipment	$ —	$ —	$ 1,403

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 in the United States and are organized in the following three reporting segments: (1) Oil and Natural Gas, (2) Contract Drilling, and (3) Mid-Stream.

Oil and Natural Gas. Carried out by our subsidiary, Unit Petroleum Company, 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 mainly in Oklahoma and Texas, and to a lesser extent, in Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Utah, and Wyoming.

Contract Drilling. Carried out by our subsidiary, 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 mainly in Oklahoma, Texas, New Mexico, Wyoming, and North Dakota.

Mid-Stream. Carried out by our subsidiary, Superior, we buy, sell, gather, transport, process, and treat natural gas for our own account and for third parties. Mid-stream operations are performed in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

NOTE 2 – 2020 EMERGENCE FROM VOLUNTARY REORGANIZATION UNDER CHAPTER 11

Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On May 22, 2020, the Debtors filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. The Chapter 11 proceedings were jointly administered under 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.

On August 6, 2020, the bankruptcy court entered the "Findings of Fact, Conclusions of Law, and Order (I) approving the Disclosure Statement on a Final Basis and (II) confirming the Plan on a final basis. On September 3, 2020, the conditions to effectiveness for the Plan were satisfied, and the Debtors emerged from Chapter 11.

Following emergence, we implemented the Plan as follows:

- Each lender under the (i) the Unit credit agreement, and (ii) the DIP Credit Agreement received (or was entitled to receive) its pro rata share of revolving loans, term loans, and letter of credit participation under the Exit Credit Agreement, in exchange for the lender’s allowed claims under the Unit credit agreement or DIP Credit Agreement;
- Each lender under the Unit credit agreement and the DIP Credit Agreement received its pro rata share of an equity fee under the exit facility equal to 5% of the New Common Stock (subject to dilution by shares reserved for issuance under a management incentive plan and upon exercise of the warrants described below);
- The company issued a total of 12.0 million shares of New Common Stock at a par value of $0.01 per share to be subsequently distributed in accordance with the Plan;
- Each holder of the Notes received its pro rata share of New Common Stock based on equity allocations at each of Unit, UDC, and UPC in exchange for the holder’s allowed Notes claim;
- Each holder of an allowed general unsecured claim against Unit or UPC was entitled to receive its pro rata share of New Common Stock based on equity allocations at each of Unit and UPC, respectively;
- A disputed claims reserve was established for distribution of New Common Stock on allowance of certain disputed general unsecured claims;

- Each holder of an allowed general unsecured claim against UDC, 8200 Unit, Unit Drilling Colombia and Unit Drilling USA received payment or will receive payment in full for that claim in the ordinary course of business; and
- Each retained or former employee with a claim for vested severance benefits, who opted into a settlement, received or will receive cash payment(s) for the claim in lieu of an allocation of New Common Stock otherwise provided to holders of general unsecured claims.

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 New 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.

Warrants

Each holder of the Old Common Stock outstanding before the Effective 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 will initially be exercisable for one share of New Common Stock, subject to adjustment as provided in the Warrant Agreement. The exercise price of the Warrants will be determined, and the Warrants will become exercisable, once the Debtors have completed the claims reconciliation process and resolved any objections to disputed claims under the Bankruptcy Petitions. The initial exercise price per share for the Warrants will be set at an amount that implies a recovery by holders of the Subordinated Notes of the $650 million principal amount of the Subordinated Notes plus interest thereon to the May 15, 2021 maturity date of the Notes. 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, dissolutions or winding up of the company (such earliest date, the Expiration Date). Each Warrant that is not exercised on or before the Expiration Date will expire, and all rights under that Warrant and the Warrant Agreement will cease on the Expiration Date.

The warrants issued to holders of the company's Old Common Stock that did not opt-out of the releases under the Plan and that owned their shares of old common stock through Direct Registration are outlined below:

Issuance Date	Warrants Issued
December 21, 2020	1,764,164
February 11, 2021	42,511
July 29, 2021	10,521
October 13, 2021	5,005
Total	1,822,201

The company expects to issue approximately 21,117 more Warrants to the holders of the Old Common Stock that did not opt-out of the releases under the Plan and owned their shares through Direct Registration.

Events of Default

The filing of the Chapter 11 Cases, in addition to other events of default including cross-defaults, constituted an event of default that accelerated the company's obligations under the Unit credit agreement and the indenture governing the Notes. Under the Bankruptcy Code, the creditors under these debt agreements were stayed from taking any action against the company. Superior and its subsidiaries were not debtors in the Chapter 11 Cases, and the Chapter 11 Cases did not result in an event of default under the Superior credit agreement. In addition, the Debtors' filing of the bankruptcy petitions constituted a termination event under the Debtors' hedge agreements, which allowed the counterparties to those hedge agreements to terminate the outstanding hedges, as those termination events were not stayed by the Chapter 11 Cases.

On filing the Chapter 11 Cases, Unit entered into a Continuation Agreement (Continuation Agreement) with Superior, SPC Midstream Operating, L.L.C., and SP Investor to continue the parties' contractual relationships during the Chapter 11 Cases under the governance, operational, and related agreements entered into by those parties at the formation of the company's midstream joint venture with SP Investor, which agreements contained certain provisions that otherwise would have been triggered by filing the Chapter 11 Cases.

Liquidity and Borrowings

The Debtors entered into the DIP Credit Agreement. Before repayment and termination on the Effective Date, borrowings under the DIP Credit Agreement would have matured on the earliest of (i) September 22, 2020 (subject to a two-month extension to be approved by the DIP lenders), (ii) the sale of all or substantially all the assets of the Debtors under Section 363 of the Bankruptcy Code or otherwise, (iii) the effective date of a plan of reorganization or liquidation in the Chapter 11 Cases, (iv) the entry of an order by the bankruptcy court dismissing any of the Chapter 11 Cases or converting such Chapter 11 Cases to a case under Chapter 7 of the Bankruptcy Code, and (v) the date of termination of the DIP lenders' commitments and the acceleration of any outstanding extensions of credit, in each case, under the DIP Credit Agreement and subject to the bankruptcy court's orders.

On the Effective Date, the DIP Credit Agreement was repaid in full and terminated. Following the Debtors' emergence from the Chapter 11 Cases, each holder of an allowed claim under the DIP Credit Agreement received its pro rata share of revolving loans, term loans, and letter-of-credit participations under the Exit credit agreement. In addition, each holder received or was entitled to receive its pro rata share of an equity fee under the exit facility equal to 5% of the New Common Stock (subject to dilution by shares reserved for issuance under a management incentive plan and on exercise of the Warrants).

Also on the Effective Date, under the Plan, we entered into an amended and restated credit agreement (Exit credit agreement). Refer to Note 10 – Long-Term Debt And Other Long-Term Liabilities for the terms of the Exit credit agreement.

The Debtors discontinued recording interest on liabilities subject to compromise as of the filing of the Chapter 11 Cases. Contractual interest on liabilities subject to compromise not reflected in the consolidated statements of operations for the eight months ended August 31, 2020 was approximately $12.4 million, respectively, representing interest expense from the filing date through August 31, 2020. In addition, the Debtors did not make the May 15, 2020 $21.5 million required interest payment on the Notes.

NOTE 3 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. We have consolidated the activities of Superior, a 50/50 joint venture between Unit and SP Investor Holdings, LLC which qualifies as a VIE under generally accepted accounting principles in the United States (U.S. GAAP), for each of the periods presented in the consolidated financial statements. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power to direct those activities that most significantly affect the economic performance of Superior as further described in Note 20 – Variable Interest Entities. All intercompany transactions and accounts have been eliminated.

During 2021, management identified an error in the initial allocation of equity between Unit Corporation and non-controlling interests as of the Fresh Start Reporting 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/(loss) or shareholders' equity.

2020 Reorganization and Fresh Start Accounting. The consolidated financial statements in Note 25 - Fresh Start Accounting have been prepared in accordance with Financial Accounting Standard Board (FASB) ASC Topic 852, *Reorganizations*. We evaluated the events between September 1, 2020 and September 3, 2020 and concluded that the use of an accounting convenience date of September 1, 2020 (Fresh Start Reporting Date) would not have a material impact to the consolidated financial statements. This was reflected in our consolidated balance sheets as of September 1, 2020. Accordingly, our consolidated financial statements and notes after September 1, 2020, are not comparable to the consolidated financial statements and notes before that date. We refer to the reorganized company in these consolidated financial statements and notes as the "Successor" for periods subsequent to August 31, 2020, and "Predecessor" for periods prior to September 1, 2020, and the consolidated financial statements and notes have been presented with a "black line" division to delineate the lack of comparability between the Predecessor and Successor periods.

We have applied the relevant guidance provided in U.S. GAAP regarding the accounting and financial statement disclosures for entities that have filed petitions with the bankruptcy court and reorganized as going concerns in preparing the consolidated financial statements and notes through the period ended August 31, 2020. That guidance requires certain transactions and events that were directly related to our reorganization be distinguished from our normal business operations for periods after our bankruptcy filing on May 22, 2020 or post-petition periods. Accordingly, certain expenses, realized gains, and losses and provisions that were realized or incurred in the Chapter 11 Cases have been included in "Reorganization items, net" on our consolidated statements of operations.

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;
- reorganization fair value as of the Effective Date,
- grant date fair value of stock-based compensation;
- workers' compensation liabilities;
- contingency, litigation, and environmental liabilities;
- and realizability of deferred tax assets;

Cash and Cash Equivalents. We include as cash and cash equivalents all cash on hand and on deposit, as well as highly liquid investments with maturities of three months or less which are readily convertible into known amounts of cash. The financing section of our consolidated statements of cash flows reflects bank overdraft activity. Bank overdrafts are checks issued before the end of the period, but not presented to our bank for payment before the end of the period. There were no bank overdrafts as of December 31, 2021 and $2.6 million as of December 31, 2020.

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 in 2021 or 2020.

Capitalized costs are amortized on a units-of-production method based on proved oil and natural gas reserves. The calculation of DD&A includes all capitalized costs, estimated future expenditures to be incurred in developing proved reserves, and estimated dismantlement and abandonment costs, net of estimated salvage values less accumulated amortization, unproved properties, and equipment not placed in service. The average rates used for DD&A were $2.67, $4.21, and $7.77 per Boe for the year ended December 31, 2021, the four months ended December 31, 2020, and the eight months ended August 31, 2020.

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 our investment in our oil and natural gas properties. There were no intercompany drilling services provided for elimination in the year ended December 31, 2021, four months ended December 31, 2020, or eight months ended August 31, 2020.

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, corporate land and building, transportation equipment, and other property and equipment. Drilling equipment, gas gathering and processing equipment, corporate land and building, 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. Prior to emergence from bankruptcy, we recorded depreciation of drilling equipment using the units-of-production method based on estimated useful lives starting at 15 years, including a minimum provision of 20% of the active rate when the equipment is idle, unless idle for greater than 48 months, then it was depreciated at the full active rate. We also used the composite method of depreciation for drill pipe and collars and calculate the depreciation by footage drilled compared to total estimated remaining footage. As of emergence and thereafter, we elected to depreciate all drilling assets utilizing the straight-line method over the estimated useful lives of the assets ranging from four to ten years. Depreciation on our former corporate building was computed using the straight-line method over the estimated useful life of 39 years. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from three to 15 years.

Impairment and disposal. 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.

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 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.

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 in 2021 or 2020.

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 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.

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 gain (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 receipts (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 $0.6 million on certain wells where we estimate that insufficient reserves are available for us to recover our under-production from future production volumes and a liability of $1.1 million on certain properties where there are insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes as of December 31, 2021. 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. We recognize 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. The liability will continue to be adjusted to fair value at each reporting period until the warrants meet the definition of an equity instrument, at which time they will be reported as shareholders' equity and no longer subject to future fair value adjustments.

Recently Issued Accounting Standards

Reference Rate Reform (Topic 848)—Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The FASB issued ASU 2020-04 and ASU 2021-01 which provide and clarify optional expedients and exceptions for applying generally accepted accounting principles to contract modifications, subject to meeting certain criteria, that reference LIBOR or another reference rate expected to be discontinued. The amendments within these ASUs will be in effect for a limited time beginning March 12, 2020, and an entity may elect to apply the amendments prospectively through December 31, 2022. We have not yet elected to use the optional guidance and continue to evaluate the options provided by ASU 2020-04 and ASU 2021-01.

Debt—Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging— Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity. The FASB issued ASU 2020-06 which simplifies the accounting for convertible instruments by removing certain accounting models which separate the embedded conversion features from the host contract for convertible instruments. The ASU further removes certain settlement conditions that are required for equity contracts to qualify for the derivative scope exception and simplifies the diluted earnings per share calculation in certain areas. The ASU is effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. We will adopt ASU 2020-06 effective January 1, 2022. The adoption of this ASU is not expected to have a material impact on our consolidated financial statements.

Recently Adopted Accounting Standards

Income Taxes (Topic 740)—Simplifying the Accounting for Income Taxes. The FASB issued ASU 2019-12 to simplify the accounting for income taxes by removing certain exceptions to the general principles in Topic 740. The amendments also improve consistent application of and simplify GAAP for other areas of Topic 740 by clarifying and amending existing guidance. The amendment is effective for reporting periods beginning after December 15, 2020. The adoption of this standard did not have a material impact to our consolidated financial statements.

NOTE 4 - IMPAIRMENTS

Oil and Natural Gas Properties

2021

There were no impairments recorded during the year ended December 31, 2021.

2020

During the four months ended December 31, 2020, the application of the full cost accounting rules resulted in non-cash ceiling test write-downs of $26.1 million pre-tax primarily due to the use of average 12-month historical commodity prices for the ceiling test versus the forward prices used for our Fresh Start fair value estimates. These charges are included within impairments in our consolidated statements of operations.

During the eight months ended August 31, 2020, we determined our undeveloped acreage would not be fully developed and thus the carrying values of certain of our unproved oil and gas properties were not recoverable resulting in an impairment of $226.5 million. That impairment had a corresponding increase to our depletion base and contributed to our recorded full cost ceiling impairment. We recorded a non-cash ceiling test write-down of $393.7 million pre-tax ($346.6 million, net of tax) during the eight months ended August 31, 2020 due to the reduction for the 12-month average commodity prices and the impairment of our unproved oil and gas properties described above. These charges are included within impairments in our consolidated statements of operations.

In addition to the impairment evaluations of our proved and unproved oil and gas properties in the eight months ended August 31, 2020, we also evaluated the carrying value of our salt water disposal assets. Based on our revised forecast, we determined that some were no longer expected to be used and wrote off the assets for total expense of $17.6 million during the eight months ended August 31, 2020. These amounts are reported in loss on abandonment of assets in our consolidated statements of operations.

Contract Drilling

2021

There were no impairments recorded during the year ended December 31, 2021.

2020

During the eight months ended August 31, 2020, we recorded expense of $1.1 million related to the write-down of certain equipment that we consider abandoned. These amounts are reported in loss on abandonment of assets in our consolidated statements of operations.

During the eight months ended August 31, 2020, due to market conditions, we performed impairment testing on two asset groups which were comprised of our SCR diesel-electric drilling rigs and our BOSS drilling rigs. We concluded that the net book value of the SCR drilling rigs asset group was not recoverable through estimated undiscounted cash flows and recorded a non-cash impairment charge of $407.1 million in addition to non-cash impairment charges of $3.0 million for other miscellaneous drilling equipment. These charges are included within impairments in our consolidated statements of operations. We concluded that no impairment was needed on the BOSS drilling rigs asset group as of March 31, 2020 as the undiscounted cash flows exceeded the $242.5 million carrying value of the asset group by a relatively minor margin. Some of the more sensitive assumptions used in evaluating the contract drilling rigs asset groups for potential impairment included forecasted utilization, gross margins, salvage values, discount rates, and terminal values. There were no additional triggering events identified during the eight months ended August 31, 2020 or four months ended December 31, 2020.

Mid-Stream

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.

2020

During the three months ended March 31, 2020, we determined that the carrying value of certain long-lived asset groups in southern Kansas, and central Oklahoma where lower pricing is expected to impact drilling and production levels, are not recoverable and exceeded their estimated fair value. We recorded non-cash impairment charges of $64.0 million based on the estimated fair value of the asset groups. These charges are included within impairments in our consolidated statements of operations. There were no additional triggering events identified during the eight months ended August 31, 2020 or one month ended September 30, 2020.

NOTE 5 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Our revenue streams are reported under our three segments: oil and natural gas, contract drilling, and mid-stream. This is our disaggregation of revenue and how our segment revenue is reported (as reflected in Note 23 – Industry Segment Information). Revenue from the oil and natural gas segment is derived from sales of our oil and natural gas production. Revenue from the contract drilling segment is derived by contracting with upstream companies to drill an agreed-on number of wells or provide drilling rigs and services over an agreed-on period. Revenue from the Mid-Stream segment is derived from gathering, transporting, and processing natural gas production and selling those commodities.

We satisfy the performance obligation under each segment's contracts as follows:

- contract drilling and mid-stream contracts - satisfy the performance obligations over the agreed-on time;
- oil and natural gas contracts - satisfy the performance obligation with each volume delivery.

For oil and natural gas contracts, as it is more feasible, we account for these deliveries monthly.

Per the contracts for all segments, customers pay for the services/goods received monthly within an agreed number of days following the end of the month. Other than the mid-stream demand fees and shortfall fees discussed further below, there were no other contract assets or liabilities falling within the scope of this accounting pronouncement.

Oil and Natural Gas Revenues

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 Revenues

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 related 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 Contracts Revenues

Revenues 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. The typical revenue contracts used by this segment are gas gathering and processing agreements as well as product sales. We recognize 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.

The table below shows the changes in our contract asset and contract liability balances during periods presented which are primarily associated with demand fees and the impact to gas gathering and processing revenues:

	Classification on the Consolidated Balance Sheets	Successor December 31, 2021	Successor December 31, 2020	Change
			(In thousands)	
Assets				
Current contract assets	Prepaid expenses and other	$ 174	$ 6,084	$ (5,910)
Non-current contract assets	Other assets	—	173	(173)
Total contract assets		$ 174	$ 6,257	$ (6,083)
Liabilities				
Current contract liabilities	Current portion of other long-term liabilities	$ 1,588	$ 2,583	$ (995)
Non-current contract liabilities	Other long-term liabilities	200	1,589	(1,389)
Total contract liabilities		1,788	4,172	(2,384)
Contract assets (liabilities), net		$ (1,614)	$ 2,085	$ (3,699)

Included below is the adjustment to demand fees from adopting ASC 606 over the remaining term of the contracts as of December 31, 2021.

Contract	Remaining Term of Contract	2022	2023 and beyond	Total Remaining Impact to Revenue
			(In thousands)	
Demand fee contracts	1 - 10 months	$ 1,374	$ —	$ 1,374

NOTE 6 – ACQUISITIONS AND DIVESTITURES

Oil and Natural Gas

There was no significant acquisition activity during the year ended December 31, 2021 or the four months ended December 31, 2020. We acquired $0.4 million of producing and other oil and natural gas properties during the eight months ended August 31, 2020.

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 is expanding the Divestiture Program to now include the potential sale of additional properties, including up to all of UPC's oil and gas properties and reserves. On January 20, 2022, the company announced that it has retained a financial advisor and launched the process.

On March 8, 2022, the company closed on the sale of wells and related leases located near the Oklahoma Panhandle for $5.0 million, subject to customary closing and post-closing adjustments with an effective date of December 1, 2021. No gain or loss was recognized as the sale of these assets 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 $19.5 million, subject to customary closing and post-closing adjustments. No gain or loss was recognized as the sale of these assets 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 related leases located in Reno and Stafford Counties, Kansas for $7.1 million, subject to customary closing and post-closing adjustments. No gain or loss was recognized as the sale of these assets did not result in a significant alteration of the full cost pool.

We also sold $5.0 million of other non-core oil and natural gas assets, net of related expenses, during the year ended December 31, 2021, compared to $0.4 million during the four months ended December 31, 2020, and $1.2 million during the eight months ended August 31, 2020. No gain or loss was recognized as the sale of these assets did not result in a significant alteration of the full cost pool.

Contract Drilling

There was no significant acquisition activity during the year ended December 31, 2021, the four months ended December 31, 2020, or eight months ended August 31, 2020.

We sold non-core contract drilling assets for proceeds of $12.7 million, net of related expenses, during the year ended December 31, 2021, compared to $1.3 million during the four months ended December 31, 2020, and $4.8 million during the eight months ended August 31, 2020. These proceeds resulted in net gains of $10.1 million during the year ended December 31, 2021, compared to $0.5 million during the four months ended December 31, 2020, and $1.4 million during the eight months ended August 31, 2020.

Mid-Stream

In November 2021, we 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 acquisition activity during the year ended December 31, 2020.

There was no significant divestiture activity during the year ended December 31, 2021, the four months ended December 31, 2020, or eight months ended August 31, 2020.

Corporate and Other

In September 2021, we closed the sale of our corporate headquarters building and land for $35.0 million 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 7 – CAPITAL STOCK

In June 2021, we repurchased an aggregate of 600,000 shares of our common stock from the Lenders (as defined in Note 10 - Long-Term Debt And Other Long-Term Liabilities) which received these shares as an exit fee during our reorganization. The Lenders were paid $15.00 per share for their respective shares, for an aggregate cash purchase price of $9.0 million. The cash purchase price and direct acquisition costs are reflected as treasury stock on the consolidated balance sheets as of December 31, 2021.

In June 2021, our board of directors (the Board) authorized repurchasing up to $25.0 million of our outstanding common stock. In October 2021, the Board authorized an increase from $25.0 million of authorized repurchases to $50.0 million. The repurchases will be made through open market purchases, privately negotiated transactions, or other available means. We have 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, 2021, we had repurchased a total of 1,271,963 shares at an average share price of $32.57 for an aggregate purchase price of $41.4 million under the repurchase program.

During the year ended December 31, 2021, we also repurchased 78,000 shares in a privately negotiated transaction at a share price of $19.07 which were not part of the repurchase program.

The cumulative number of shares repurchased as of December 31, 2021 totaled 1,949,963, resulting in outstanding shares of 10,050,037.

NOTE 8 – EARNINGS (LOSS) PER SHARE

Information related to the calculation of earnings (loss) per share attributable to Unit Corporation for the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020 is as follows:

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2021 (Successor)			
Basic earnings attributable to Unit Corporation per common share	$ 60,647	11,405	$ 5.32
Effect of dilutive restricted stock units	—	115	(0.06)
Diluted earnings attributable to Unit Corporation per common share	$ 60,647	11,520	$ 5.26
For the four months ended December 31, 2020 (Successor)			
Basic loss attributable to Unit Corporation per common share	$ (18,140)	12,000	$ (1.51)
For the eight months ended August 31, 2020 (Predecessor)			
Basic loss attributable to Unit Corporation per common share	$ (931,012)	53,368	$ (17.45)

There were no potentially dilutive shares for inclusion during the eight months ended August 31, 2020 and four months ended December 31, 2020 as the company's stock-based awards outstanding immediately before the Effective Date were cancelled on the Effective Date.

The following stock options were not included in the computation of diluted earnings (loss) per share because the option exercise prices were greater than the average market price of our common stock for the year ended December 31, 2021:

	2021
Stock options	361,418
Average exercise price	$ 45.00

NOTE 9 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31:

	Successor 2021	Successor 2020
	(In thousands)	
Employee costs	$ 10,005	$ 8,878
Lease operating expenses	3,451	6,405
Capital expenditures	3,962	—
Taxes	3,320	2,324
Interest payable	296	884
Legal settlement (Note 21)	—	2,070
Other	1,416	1,182
Total accrued liabilities	$ 22,450	$ 21,743

NOTE 10 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

Long-term debt consisted of the following as of December 31:

	Successor		Successor	
	2021		2020	
	(In thousands)			
Current portion of long-term debt:				
Exit credit agreement with an average interest rate of 6.7%	$	—	$	600
Long-term debt:				
Exit credit agreement with an average interest of 6.7%		—		98,400
Superior credit agreement with an average interest rate of 2.1% at December 31, 2021		19,200		—
Total long-term debt	$	19,200	$	98,400

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, (ii) the guarantors, including the company and all its subsidiaries existing as of the Effective Date (other than Superior Pipeline Company, L.L.C. and its subsidiaries), (iii) the lenders under the agreement (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. Revolving Loans and Term Loans (each as defined in the Exit credit agreement) may be Eurodollar Loans or ABR Loans (each as defined in the Exit credit agreement). Revolving Loans that are Eurodollar Loans will bear 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. Revolving Loans that are ABR Loans will bear 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 are Eurodollar Loans will bear interest at a rate per annum equal to the Adjusted LIBO Rate for the applicable interest period plus 625 basis points. Term Loans that are ABR Loans will bear 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.

The Exit credit agreement requires the company to comply with certain financial ratios, including a covenant that the company will not permit the Net Leverage Ratio (as defined in the Exit credit agreement) as of the last day of the fiscal quarters ended (i) December 31, 2020 and March 31, 2021, to be greater than 4.00 to 1.00, (ii) June 30, 2021 and September 30, 2021, to be greater than 3.75 to 1.00, and (iii) December 31, 2021 and any fiscal quarter thereafter, to be greater than 3.25 to 1.00. In addition, beginning with the fiscal quarter ended December 31, 2020, the company may not (a) permit the Current Ratio (as defined in the Exit credit agreement) as of the last day of any fiscal quarter to be less than 1.00 to 1.00 or (b) permit the Interest Coverage Ratio (as defined in the Exit credit agreement) as of the last day of any fiscal quarter to 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. Unit was in compliance with these covenants as of December 31, 2021.

The Exit credit agreement is secured by first-priority liens on substantially all the personal and real property assets of the Borrowers and the Guarantors, including the company's ownership interests in Superior.

We had no current or long-term borrowings, and $2.4 million of letters of credit outstanding under the Exit credit agreement as of December 31, 2021, compared to $0.6 million current and $98.4 million long-term borrowings, and $5.5 million of letters of credit outstanding as of December 31, 2020.

Predecessor Unit Credit Agreement. Before the filing of the Chapter 11 Cases, the Predecessor Unit credit agreement had a scheduled maturity date of October 18, 2023 that would have accelerated to November 16, 2020 if, by that date, all the Notes were not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023 (Credit Agreement Extension Condition). Filing the bankruptcy petitions on May 22, 2020 constituted an event of default that accelerated our obligations under the Unit credit agreement, and the lenders' rights of enforcement under the Unit credit agreement were automatically stayed because of the Chapter 11 Cases.

Before filing the Chapter 11 Cases, we were charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varied based on the amount borrowed as a percentage of the total borrowing base. Total amendment fees of $3.3 million in origination, agency, syndication, and other related fees were being amortized over the life of the Unit credit agreement. Due to the remaining commitments under the Unit credit agreement being terminated by the lenders', the unamortized debt issuance costs of $2.4 million were written off during the eight months ended August 31, 2020. Under the Unit credit agreement, we pledged as collateral 80% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties. Under the mortgages covering those oil and gas properties, UPC also pledged certain items of its personal property.

Before filing the Chapter 11 Cases, any part of the outstanding debt under the Unit credit agreement could be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest was computed as the LIBOR base for the term plus 1.50% to 2.50% depending on the level of debt as a percentage of the borrowing base and was payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest equal to the higher of the prime rate specified in the Unit credit agreement and the sum of the Federal Funds Effective Rate (as defined in the Unit credit agreement) plus 0.50%, but in no event would the interest on those borrowings be less than LIBOR plus 1.00% plus a margin. Interest was payable at the end of each month or at the end of each LIBOR contract and the principal may be repaid in whole or in part at any time, without a premium or penalty.

On the Effective Date, each lender under the Predecessor Unit credit agreement and the DIP Credit Agreement (as defined below) received its pro rata share of revolving loans, term loans and letter-of-credit participations under the Exit credit agreement, in exchange for that lender's allowed claims under the Predecessor Unit credit agreement or the DIP 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. The amounts borrowed under the Superior credit agreement bear 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%. The obligations under the Superior credit agreement are secured by mortgage liens on certain of Superior's processing plants and gathering systems. The credit agreement provides that if ICE Benchmark Administration no longer reports the LIBOR or Administrative Agent determines in good faith that the rate so reported no longer accurately reflects the rate available to Lender in the London Interbank Market or if such index no longer exists or accurately reflects the rate available to Administrative Agent in the London Interbank Market, Administrative Agent may select a replacement index.

Superior is charged a commitment fee of 0.375% on the amount available but not borrowed which varies based on the amount borrowed as a percentage of the total borrowing base.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio (as defined in the Superior credit agreement) for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio (as defined in the Superior credit agreement) of not greater than 4.00 to 1.00. The agreement also contains several customary covenants that restrict (subject to certain exceptions) Superior's ability to incur additional indebtedness, create additional liens on its assets, make investments, pay distributions, sign sale and leaseback transactions, engage in certain transactions with affiliates, engage in mergers or consolidations, sign hedging arrangements, and acquire or dispose of assets. Superior was in compliance with these covenants as of December 31, 2021

The Superior credit agreement is used to fund capital expenditures and acquisitions and provide general working capital and letters of credit. We had $19.2 million of borrowings and $0.5 million of letters of credit outstanding under the Superior credit agreement as of December 31, 2021, compared to no borrowings and $2.6 million of letters of credit outstanding as of December 31, 2020.

Unit is not a party to and does not guarantee Superior's credit agreement. Superior and its subsidiaries were not debtors in the Chapter 11 Cases, and the Superior credit agreement was not affected by Unit's bankruptcy.

Predecessor 6.625% Senior Subordinated Notes. The Predecessor 6.625% Notes (Predecessor Notes) were issued under an Indenture dated as of May 18, 2011, between the company and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms of and providing for issuing the Predecessor Notes.

As a result of Unit's emergence from bankruptcy, the Predecessor Notes were cancelled and our liability under the Predecessor Notes was discharged as of the Effective Date. Holders of the Predecessor Notes were issued shares of New Common Stock in accordance with the Plan.

Predecessor DIP Credit Agreement. As contemplated by the Restructuring Support Agreement between the company and certain of the Predecessor Note holders and our lenders, the company and the other Debtors entered into a Superpriority Senior Secured Debtor-in-Possession Credit Agreement dated May 27, 2020 (DIP credit agreement), among the Debtors, the lenders under the facility (the DIP lenders), and BOKF, NA dba Bank of Oklahoma, as administrative agent, under which the DIP lenders agreed to provide us with a $36.0 million multiple-draw loan facility (DIP credit facility). The bankruptcy court entered an interim order on May 26, 2020 approving the DIP credit facility, permitting the Debtors to borrow up to $18.0 million on an interim basis. On June 19, 2020, the bankruptcy court granted final approval of the DIP credit facility.

Before its repayment and termination on the Effective Date, borrowings under the DIP credit facility matured on the earliest of (i) September 22, 2020 (subject to a two-month extension to be approved by the DIP Lenders), (ii) the sale of all or substantially all the assets of the Debtors under Section 363 of the Bankruptcy Code or otherwise, (iii) the effective date of a plan of reorganization or liquidation in the Chapter 11 Cases, (iv) the entry of an order by the bankruptcy court dismissing any of the Chapter 11 Cases or converting such Chapter 11 Cases to a case under Chapter 7 of the Bankruptcy Code and (v) the date of termination of the DIP lenders' commitments and the acceleration of any outstanding extensions of credit, in each case, under the DIP credit facility under and subject to the DIP Credit Agreement and the bankruptcy court's orders.

On the Effective Date, the DIP credit facility was paid in full and terminated, and each holder of an allowed claim under the DIP credit facility received its pro rata share of revolving loans, term loans, and letter-of-credit participations under the Exit credit agreement. In addition, each holder was issued its pro rata share of an equity fee under the Exit credit agreement equal to 5% of the New Common Stock (subject to dilution by shares reserved for issuance under a management incentive plan and on exercise of the Warrants).

For further information about the DIP Credit Agreement, please see Note 2 – 2020 Emergence From Voluntary Reorganization Under Chapter 11.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following as of December 31:

	Successor 2021	Successor 2020
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 25,688	$ 23,356
Workers' compensation	7,925	10,164
Finance lease obligations	—	3,216
Contract liabilities	1,788	4,172
Separation benefit plans	2,022	4,201
Gas balancing liability	1,090	3,997
Other long-term liabilities	—	1,321
	38,513	50,427
Less: current portion	5,574	11,168
Total other long-term liabilities	$ 32,939	$ 39,259

NOTE 11 – ASSET RETIREMENT OBLIGATIONS

The following table summarizes activity for our estimated AROs during the year ended December 31, 2021 (in thousands):

December 31, 2020 (Successor)	$ 23,356
Accretion of discount	1,892
Liability incurred	7
Liability settled	(1,140)
Liability sold	(1,935)
Revision of estimates [(1)]	3,507
December 31, 2021 (Successor)	25,688
Less: current portion (Successor)	2,537
Long-term ARO liability (Successor)	$ 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.

The following table summarizes activity for our estimated AROs during the eight months ended August 31, 2020 and the four months ended December 31, 2020 (in thousands):

December 31, 2019 (Predecessor)	$ 66,627
Accretion of discount	1,545
Liability incurred	465
Liability settled	(838)
Liability sold	(487)
Revision of estimates [1]	(28,328)
August 31, 2020 (Predecessor)	38,984
Fresh start adjustments	(14,393)
August 31, 2020 (Successor)	24,591
Accretion of discount	467
Liability incurred	151
Liability settled	(95)
Revision of estimates [1]	(1,758)
December 31, 2020 (Successor)	23,356
Less: current portion (Successor)	2,121
Long-term ARO liability (Successor)	$ 21,235

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 12 – 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 summarizes activity for our workers' compensation liability during the year ended December 31, 2021 (in thousands):

December 31, 2020 (Successor)	$ 10,164
Claims and valuation adjustments	(1,834)
Payments	(405)
December 31, 2021 (Successor)	7,925
Less: current portion (Successor)	1,221
Long-term workers' compensation liability (Successor)	$ 6,704

The following table summarizes activity for our workers' compensation liability during the eight months ended August 31, 2020 and the four months ended December 31, 2020 (in thousands):

December 31, 2019 (Predecessor)	$ 11,511
Claims and valuation adjustments	906
Payments	(427)
August 31, 2020 (Predecessor)	11,990
Fresh start adjustments	—
August 31, 2020 (Successor)	11,990
Claims and valuation adjustments	(1,679)
Payments	(147)
December 31, 2020 (Successor)	10,164
Less: current portion (Successor)	1,705
Long-term workers' compensation liability (Successor)	$ 8,459

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, 2021 and 2020 are $4.0 million and $5.2 million, respectively, and are included in Other assets on our consolidated balance sheets.

NOTE 13 – 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 financials 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.

A reconciliation of income tax expense (benefit) computed by applying the federal statutory rate to pre-tax income (loss) to our effective income tax expense (benefit) during the periods indicated is as follows:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
Income tax expense (benefit) computed by applying the statutory rate	$ 12,772	$ (3,001)	$ (190,103)
State income tax expense (benefit), net of federal benefit	2,129	(500)	(31,684)
Warrant liability revaluation	4,640	—	—
Restricted stock shortfall	—	—	7,404
Non-controlling interest in Superior	(3,046)	(1,017)	7,504
Goodwill impairment	—	—	—
Valuation allowance	(16,612)	4,047	177,284
Reorganization adjustments	—	—	14,152
Statutory depletion and other	290	169	813
Income tax expense (benefit)	$ 173	$ (302)	$ (14,630)

The company's total provision for income taxes consisted of the following during the periods indicated:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
Current taxes:			
Federal	$ —	$ —	$ (917)
State	173	(302)	—
	173	(302)	(917)
Deferred taxes:			
Federal	—	—	(16,663)
State	—	—	2,950
	—	—	(13,713)
Total provision for income taxes	$ 173	$ (302)	$ (14,630)

Net deferred tax assets and liabilities are comprised of the following as of December 31:

	Successor 2021	Successor 2020
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 23,819	$ 22,051
Net operating loss carryforward	94,441	100,236
Depreciation, depletion, amortization, and impairment	68,001	80,947
Alternative minimum tax and research and development tax credit carryforward	1,738	1,738
	187,999	204,972
Deferred tax liability:		
Investment in Superior	(3,626)	(3,987)
Net deferred tax asset	184,373	200,985
Valuation allowance	(184,373)	(200,985)
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 has recorded a full valuation allowance, reducing the net deferred tax asset to zero. The company has maintained this conclusion as of December 31, 2021 and 2020. The company will continue to evaluate whether the valuation allowance is needed in future reporting periods and it will remain until the company can conclude that the net deferred tax assets are more likely than not to be realized. 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, sustained significant improvements in commodity prices, a sustained significant increase in rig utilization and/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 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 2017 or state income tax examinations by state taxing authorities for years before 2016. As of December 31, 2021, and after consideration of the tax attribute reductions of IRC Section 108 and finalization of the company’s 2020 federal income tax return, the company has an expected federal net operating loss carryforward of $385.5 million of which $190.5 million is subject to expiration between 2036 and 2037. As of December 31, 2021, our tax basis in UPC's properties was approximately $475.0 million.

NOTE 14 – EMPLOYEE BENEFIT PLANS

Separation Benefit Plans. As of the Effective 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 $3.4 million, $1.4 million, and $18.1 million during the year ended December 31, 2021, the four months ended December 31, 2020, and the eight months ended August 31, 2020, 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 2019 and 2020 plan year matching contributions were made in cash. Total 401(k) employer matching expense was $1.6 million, $0.7 million, and $1.4 million in the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020, respectively.

Salary Deferral Plan. We provided a salary deferral plan for our executives (Deferral Plan) during the eight months ended August 31, 2020 which allowed participants to defer the recognition of salary for income tax purposes until actual distribution of benefits occurred at either termination of employment, death, or certain defined unforeseeable emergency hardships. As of December 31, 2020, investments held in the Deferral Plan had been paid out to plan participants and the Deferral Plan was terminated.

NOTE 15 – 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. Payments made to Kaiser Francis Oil Company totaled $5.7 million, $0.5 million, and $1.8 million while payments received totaled $6.2 million, $0.3 million, and $1.6 million during the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020, respectively. Payments made to Cactus Drilling Company totaled $0.8 million during the year ended December 31, 2021.

One former director, G. Bailey Peyton IV, also serves as Manager and 99.5% owner of Peyton Royalties, LP, a family-controlled limited partnership that owns royalty rights in wells in several states. The company in the ordinary course of business, paid royalties, or lease bonuses, primarily due to its status as successor in interest to prior transactions and as operator of the wells involved and, sometimes, as lessee, regarding certain wells in which Mr. Peyton, members of Mr. Peyton's family, and Peyton Royalties, LP have an interest. Such payments totaled $0.4 million and $0.2 million during year ended December 31, 2021 and the eight months ended August 31, 2020, respectively.

NOTE 16 – 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 will be administered by the Board or a committee thereof 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 have been 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.

Predecessor Amended Plan and Non-Employee Directors Plan. The Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the Amended plan) allowed us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) and to non-employee directors. We recognized a reversal of expense previously recorded for the unvested awards of $2.2 million for these awards upon cancellation.

Under the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (Non-employee directors plan), on the first business day following each annual meeting of shareholders, each person who was then a member of our Board and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 3,500 shares of common stock.

On the Effective Date, the company's equity-based awards outstanding immediately before the Effective Date were cancelled along with the Amended plan and the Non-employee directors plan. The cancellations resulted in an acceleration of unrecorded stock compensation expense during the eight months ended August 31, 2020. Under the Plan, the company issued warrants to holders of those equity-based awards that were outstanding immediately before the Effective Date who did not opt out of releases under the Plan. For further information, see Note 2 – 2020 Emergence From Voluntary Reorganization Under Chapter 11.

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

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020 [1]
	(In thousands)		
Recognized stock compensation expense	$ 826	$ —	$ 6,065
Capitalized stock compensation cost for our oil and natural gas properties	$ —	$ —	$ —
Tax benefit on stock-based compensation	$ 202	$ —	$ 1,486

1. When the company's equity-based awards were cancelled on the Effective Date, we immediately recognized the expense for the cancelled awards of $1.4 million as reorganization costs.

Successor Period activity pertaining to nonvested RSUs under the LTIP is as follows:

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2020 (Successor) [(1)]	—	$ —
Granted [(2)]	315,529	26.71
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2021 (Successor) [(3)]	315,529	$ 26.71

1. There was no activity during the four months ended December 31, 2020.
2. The grants had an aggregate grant date fair value of $8.4 million. Director grants will vest 25% on each of the following dates: May 27, 2022, September 3, 2022, September 3, 2023, and September 3, 2024. Employee grants will one-third vest on each of the following dates: November 21, 2022, October 1, 2023, and October 1, 2024.
3. The aggregate compensation cost related to nonvested RSUs not yet recognized as of December 31, 2021 was $7.9 million with a weighted average remaining service period of 1.7 years.

Successor Period activity pertaining to outstanding stock options under the LTIP is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at December 31, 2020 (Successor) [(1)]	—	$ —
Granted [(2)]	361,418	45.00
Exercised	—	—
Forfeited or expired	—	—
Outstanding at December 31, 2021 (Successor) [(3)]	361,418	$ 45.00

1. There was no activity during the four months ended December 31, 2020.
2. The grants had an aggregate grant date fair value of $4.1 million and will one-third vest on each of the following dates: October 1, 2022, October 1, 2023, and October 1, 2024. The options have a five year term from the grant date.
3. The stock options outstanding as of December 31, 2021 had a weighted average remaining contractual term of 4.8 years and no aggregate intrinsic value. None of the stock options outstanding as of December 31, 2021 were exercisable. The aggregate compensation cost related to outstanding options not yet recognized as of December 31, 2021 was $3.9 million with a weighted average remaining service period of 1.8 years.

Predecessor Period activity pertaining to nonvested RSUs under the Amended plan is as follows:

Employees	Number of Time Vested Shares	Number of Performance Vested Shares	Total Number of Shares	Weighted Average Price
Nonvested at December 31, 2019 (Predecessor)	1,527,648	841,374	2,369,022	$ 18.95
Granted	—	—	—	—
Vested	(677,076)	—	(677,076)	19.95
Forfeited	(272,396)	(503,809)	(776,205)	19.28
Nonvested at August 31, 2020 (Predecessor)	578,176	337,565	915,741	$ 17.92
Cancelled	(578,176)	(337,565)	(915,741)	17.92
Nonvested at September 1, 2020 (Successor)	—	—	—	$ —

Non-Employee Directors	Number of Shares		Weighted Average Price
Nonvested at December 31, 2019 (Predecessor)	118,688	$	14.83
Granted	—		—
Vested	(48,475)		15.88
Forfeited	—		—
Nonvested at August 31, 2020 (Predecessor)	70,213	$	14.10
Cancelled	(70,213)		14.10
Nonvested at September 1, 2020 (Successor)	—	$	—

Predecessor Period activity pertaining to outstanding stock options under the Non-Employee Directors' Stock Option Plan for the identified periods is as follows:

	Number of Shares		Weighted Average Exercise Price
Outstanding at December 31, 2019 (Predecessor)	42,000	$	48.56
Granted	—		—
Exercised	—		—
Forfeited	(14,000)		41.21
Outstanding at August 31, 2020 (Predecessor)	28,000	$	52.24
Cancelled	(28,000)		52.24
Outstanding at September 1, 2020 (Successor)	—	$	—

NOTE 17 – 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, 2021, 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, 2021.

The following non-designated hedges were outstanding as of December 31, 2021:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'22 - Dec'22	Natural gas - swap	5,000 MMBtu/day	$2.61	IF - NYMEX (HH)
Jan'23 - Dec'23	Natural gas - swap	22,000 MMBtu/day	$2.46	IF - NYMEX (HH)
Jan'22 - Dec'22	Natural gas - collar	35,000 MMBtu/day	$2.50 - $2.68	IF - NYMEX (HH)
Jan'22 - Jun'22	Crude oil - swap	986 Bbl/day	$70.30	WTI - NYMEX
Jan'22 - Dec'22	Crude oil - swap	2,300 Bbl/day	$42.25	WTI - NYMEX
Jan'23 - Dec'23	Crude oil - swap	1,300 Bbl/day	$43.60	WTI - NYMEX

Warrants

We recognize 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. The liability will continue to be adjusted to fair value at each reporting period until the warrants meet the definition of an equity instrument, at which time they will be reported as shareholders' equity and no longer subject to future fair value adjustments.

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

	Balance Sheet Classification	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

	Balance Sheet Classification	As of December 31, 2020 Presented Gross	Effects of Netting	Presented Net
		(In thousands)		
Assets:				
Current commodity derivatives	Current derivative assets	$ 3,292	$ (3,292)	$ —
Long-term commodity derivatives	Non-current derivative assets	144	(144)	—
Total derivative assets		$ 3,436	$ (3,436)	$ —
Liabilities:				
Current Commodity Derivatives	Current derivative liabilities	$ 4,339	$ (3,292)	$ 1,047
Long-term Commodity Derivatives	Non-current derivative liabilities	4,803	(144)	4,659
Warrant Liability	Warrant liability	885	—	885
Total derivative liabilities		$ 10,027	$ (3,436)	$ 6,591

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

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
Loss on derivatives	$ (97,615)	$ (985)	$ (10,704)
Cash settlements paid on commodity derivatives	(44,591)	(1,133)	(4,244)
Loss on derivatives less cash settlements paid on commodity derivatives	$ (53,025)	$ 148	$ (6,460)
Loss on change in fair value of warrants	$ (18,937)	$ —	$ —

NOTE 18 – 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:

	Successor			
	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)

	Successor			
	December 31, 2020			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivative assets	$ —	$ 3,436	$ —	$ 3,436
Commodity derivative liabilities	—	(9,142)	—	(9,142)
Warrant liability	—	—	(885)	(885)
	$ —	$ (5,706)	$ (885)	$ (6,591)

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 measure the fair values of our natural gas and crude oil three-way collars using estimated discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements. We consider this a Level 3 measurement within the fair value hierarchy as the calculation uses certain generally unobservable inputs.

We determined that the non-performance risk regarding our commodity derivative counterparties was immaterial based on our valuation at December 31, 2021.
Warrant Liability. We use 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 tables summarize the activity of our recurring Level 3 fair value measurements during the periods presented:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
	(In thousands)		
Beginning of period	$ 885	$ —	$ 1,204
Issuance of warrants	—	885	—
Loss on change in warrant liability	18,937	—	—
Gain/(loss) on unsettled three-way collars	—	—	978
Settlement loss on three-way collars	—	—	(2,182)
End of period	$ 19,822	$ 885	$ —

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 value 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, 2021 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 11 – 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 is 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.

Fresh Start Accounting. See Note 26 - Fresh Start Accounting for additional disclosures of non-recurring fair value measurements associated with the qualification of fresh start under ASC 852.

NOTE 19 – 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 sets forth the maturities of our operating lease liabilities as of December 31, 2021:

	Amount (In thousands)
Ending December 31,	
2022	$ 4,382
2023	3,321
2024	2,683
2025	2,081
2026	1,484
2027 and beyond	50
Total future payments	14,001
Less: Interest	1,533
Present value of future minimum operating lease payments	12,468
Less: Current portion	3,791
Total long-term operating lease payments	$ 8,677
Weighted average remaining lease term (years)	3.8
Weighted average discount rate [(1)]	5.54 %

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.

Information about the operating and finance lease assets and liabilities on our consolidated balance sheets as of December 31, 2021 and 2020 is as follows:

	Balance Sheet Classification	Successor December 31, 2021	Successor December 31, 2020
		(In thousands)	
Assets			
Operating lease right of use assets	Right of use assets	$ 12,445	$ 5,592
Finance lease right of use assets	Property and equipment, net	—	7,281
Total lease right of use assets		$ 12,445	$ 12,873
Liabilities			
Current liabilities:			
Operating lease liabilities	Current operating lease liabilities	$ 3,791	$ 4,075
Finance lease liabilities	Current portion of other long-term liabilities	—	3,216
Non-current liabilities:			
Operating lease liabilities	Operating lease liabilities	8,677	1,445
Total lease liabilities		$ 12,468	$ 8,736

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

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
		(In thousands)	
Components of total lease cost:			
Amortization of finance leased assets	$ 1,248	$ 1,406	$ 2,757
Interest on finance lease liabilities	33	54	165
Operating lease cost	4,546	1,331	3,604
Short-term lease cost [1]	12,898	3,664	8,190
Variable lease cost	—	64	223
Total lease cost	$ 18,725	$ 6,519	$ 14,939

1. Short-term lease cost includes amounts capitalized related to our oil and natural gas segment of $1.5 million, $0.2 million, and $1.5 million for the year ended December 31, 2021, the four months ended December 31, 2020, and the eight months ended August 31, 2020, respectively.

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

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
		(In thousands)	
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows for operating leases	$ 4,605	$ 1,489	$ 3,849
Financing cash flows for finance leases	3,216	1,406	2,757
Lease liabilities recognized in exchange for new operating lease right of use assets	$ 8,745	$ —	$ —

NOTE 20 – VARIABLE INTEREST ENTITIES

On April 3, 2018, we sold 50% of the ownership interest in Superior. The 50% interest in Superior we sold was acquired by 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 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. 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.

We have determined that Superior is a VIE as the equity holders as a group (Unit Corporation and SP Investor) (Members) lack the power to control without the Operator. The Agreement and MSA give us the power to direct the activities that most significantly affect Superior's operating performance through common control of the Operator. Accordingly, Unit is considered the primary beneficiary and consolidates the financial position, operating results, and cash flows of Superior.

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.

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, 2021, liquidation distributions paid first to SP Investor of $361.7 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 $361.7 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.

Superior paid cash distributions totaling $24.7 million in April 2021 related to cumulative available cash as of March 31, 2021, $7.7 million in July 2021 related to available cash generated during the three months ended June 30, 2021, $13.9 million in October 2021 related to available cash generated during the three months ended September 30, 2021, and $19.0 million in January 2022 related to available cash generated during the three months ended December 31, 2021. Unit and SP Investor each received 50% of these distributions.

Subsequent to the Effective Date, we have allocated Unit's and SP Investor's share of earnings and losses from Superior in our consolidated statement of operations using the hypothetical liquidation at 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.

The amounts below reflect the Superior balance sheet accounts consolidated in our consolidated balance sheets without elimination of intercompany receivables from and payables to Unit:

	December 31, 2021	December 31, 2020
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 17,246	$ 11,642
Accounts receivable	42,628	27,427
Prepaid expenses and other	1,263	6,746
Total current assets	61,137	45,815
Property and equipment:		
Gas gathering and processing equipment	274,748	251,403
Transportation equipment	2,801	1,748
	277,549	253,151
Less accumulated depreciation, depletion, amortization, and impairment	53,792	10,466
Net property and equipment	223,757	242,685
Right of use assets	3,485	2,823
Other assets	2,226	2,309
Total assets	$ 290,605	$ 293,632
Current liabilities:		
Accounts payable	$ 34,010	$ 17,045
Accrued liabilities	5,292	3,777
Current operating lease liability	1,548	1,762
Current portion of other long-term liabilities	1,450	5,799
Total current liabilities	42,300	28,383
Long-term debt less debt issuance costs	19,200	—
Operating lease liability	2,036	1,013
Other long-term liabilities	—	1,589
Total liabilities	$ 63,536	$ 30,985

Subsequent Amendments to Superior Agreement and MSA

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 will no longer consolidate the financial position, operating results, and cash flows of Superior as of March 1, 2022. A loss on deconsolidation during the three months ended March 31, 2022 is possible as any difference between the March 1, 2022 estimated fair value of our retained investment in Superior and our net investment in Superior, which totaled $14.8 million as of December 31, 2021, will be recognized as a gain or loss. We will subsequently account for our investment in Superior as an equity method investment under the HLBV method.

NOTE 21 – COMMITMENTS AND CONTINGENCIES

Commitments

We have firm transportation commitments to transport our natural gas from various systems for approximately $0.9 million over the next twelve months.

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, 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.

Chapter 11 Cases

On May 22, 2020, the Debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code. The commencement of the Chapter 11 Cases automatically stayed all the proceedings and actions against the Debtors (other than certain regulatory enforcement matters). The Debtors emerged from the Chapter 11 Cases on the Effective Date. On the Effective Date, the automatic stay was terminated and replaced with the injunction provisions in the Confirmation Order and the Plan.

The commencement of the Chapter 11 Cases also automatically stayed all proceedings and actions against the Predecessor company (other than certain regulatory enforcement matters). Effective at emergence from the Chapter 11 Cases, the automatic stay was terminated and replaced with the injunction provisions in the Confirmation Order and the Plan.

Below is a summary of two lawsuits and the respective treatment and settlement of those cases.

Cockerell Oil Properties, Ltd., v. Unit Petroleum Company, No. 16-cv-135-JHP, United States District Court for the Eastern District of Oklahoma.

On March 11, 2016, a putative class action lawsuit was filed against UPC styled *Cockerell Oil Properties, Ltd., v. Unit Petroleum Compan*y in LeFlore County, Oklahoma. We removed the case to federal court in the Eastern District of Oklahoma. The plaintiff alleges that UPC wrongfully failed to pay interest with respect to late paid oil and gas proceeds under Oklahoma's Production Revenue Standards Act. The lawsuit seeks actual and punitive damages, an accounting, disgorgement, injunctive relief, and attorney fees. Plaintiff is seeking relief on behalf of royalty and working interest owners in our Oklahoma wells.

Chieftain Royalty Company v. Unit Petroleum Company, No. CJ-16-230, District Court of LeFlore County, Oklahoma.

On November 3, 2016, a putative class action lawsuit was filed against UPC styled *Chieftain Royalty Company v. Unit Petroleum Company* in LeFlore County, Oklahoma. The plaintiff alleges that UPC breached its duty to pay royalties on natural gas used for fuel off the lease premises. The lawsuit seeks actual and punitive damages, an accounting, injunctive relief, and attorney's fees. Plaintiff is seeking relief on behalf of Oklahoma citizens who are or were royalty owners in our Oklahoma wells.

Settlement

In August 2020, UPC reached an agreement to settle the above class actions. Under the settlement, UPC agreed to recognize class proof of claims in the amount of $15.75 million for Cockerell Oil Properties, Ltd. vs. Unit Petroleum Company, and $29.25 million in Chieftain Royalty Company vs. Unit Petroleum Company. Under the Plan, these settlements will be treated as allowed general unsecured claims against UPC. This settlement has been approved by the United States Bankruptcy Court for the Southern District of Texas, Houston Division in Case No. 20-32740 under the caption *In re Unit Corporation, et al.* and, in accordance with the Plan, the settlement amounts have been satisfied by distribution of the plaintiffs' proportionate share of New Common Stock.

NOTE 22 - 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.

Below is a table of the third-party customers that accounted for over 10% of each of our segments' revenues:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
Oil and Natural Gas:			
Coffeyville Resources	11%	*	*
CVR Refining, LP	*	14%	15%
Plains Marketing L.P.	*	*	11%
Drilling:			
EOG Resources, Inc.	21%	28%	20%
Citizen Energy III, LLC	20%	16%	*
Diamondback E&P, LLC	15%	*	*
Slawson Exploration Company, Inc.	12%	16%	21%
Earthstone Operating, LLC	11%	*	*
Cimarex Energy Co.	*	12%	*
QEP Resources, Inc.	*	23%	10%
Mid-Stream:			
ONEOK, Inc.	37%	28%	31%
Range Resources Corporation	11%	15%	21%
Koch Energy Services	10%	*	*
Centerpoint Energy Service, Inc.	*	*	*

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

We also had a concentration of cash with one bank of $36.6 million and $21.4 million as of December 31, 2021 and 2020, respectively, as well as a concentration of cash equivalents of $27.0 million in a money market fund comprised of U.S. Government and U.S. Treasury securities 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, 2021 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 $58.7 million of December 31, 2021.

NOTE 23 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

- Oil and natural gas,
- Contract drilling, and
- Mid-Stream

The oil and natural gas segment is engaged in the development, acquisition, and production of oil, NGLs, and natural gas properties. The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells and the mid-stream segment is engaged in the buying, selling, gathering, processing, and treating of natural gas and NGLs.

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment.

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

	Successor 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
Total expenses	107,833	67,281	329,438	840	(54,812)	450,580
General and administrative	—	—	—	21,399	3,516	24,915
(Gain) loss on disposition of assets	171	(10,143)	49	(954)	—	(10,877)
Income (loss) from operations	164,227	18,969	12,187	(21,285)	—	174,098
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)
Interest, net	—	—	(924)	(3,342)	—	(4,266)
Other	187	57	(844)	3	—	(597)
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
Corporate land and building	—	—	—	—	—	—
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, transportation equipment, furniture, and equipment.

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS— (Continued)

	Successor					
	Four Months Ended December 31, 2020					
	Oil and Natural Gas	Contract Drilling	Mid-Stream	Corporate and Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$ 57,580	$ —	$ —	$ —	$ (2)	$ 57,578
Contract drilling	—	19,413	—	—	—	19,413
Gas gathering and processing	—	—	68,369	—	(11,832)	56,537
Total revenues	57,580	19,413	68,369	—	(11,834)	133,528
Expenses:						
Operating costs:						
Oil and natural gas	26,111	—	—	—	(855)	25,256
Contract drilling	—	13,852	—	—	—	13,852
Gas gathering and processing	—	—	53,147	—	(10,978)	42,169
Total operating costs	26,111	13,852	53,147	—	(11,833)	81,277
Depreciation, depletion, and amortization	14,869	2,102	10,659	332	—	27,962
Impairments [2]	26,063	—	—	—	—	26,063
Total expenses	67,043	15,954	63,806	332	(11,833)	135,302
General and administrative	—	—	—	6,702	—	6,702
Gain on disposition of assets	(24)	(521)	(55)	(19)	—	(619)
Income (loss) from operations	(9,439)	3,980	4,618	(7,015)	(1)	(7,857)
Loss on derivatives	—	—	—	(985)	—	(985)
Reorganization items, net	—	—	—	(2,273)	—	(2,273)
Interest, net	—	—	(501)	(2,774)	—	(3,275)
Other	56	4	34	6	—	100
Income (loss) before income taxes	$ (9,383)	$ 3,984	$ 4,151	$ (13,041)	$ (1)	$ (14,290)
Identifiable assets:						
Oil and natural gas [3]	$ 236,073	$ —	$ —	$ —	$ (3,326)	$ 232,747
Contract drilling	—	81,612	—	—	(4)	81,608
Gas gathering and processing	—	—	293,632	—	(335)	293,297
Total identifiable assets [4]	236,073	81,612	293,632	—	(3,665)	607,652
Corporate land and building	—	—	—	32,382	—	32,382
Other corporate assets [5]	—	—	—	13,671	(4,002)	9,669
Total assets	$ 236,073	$ 81,612	$ 293,632	$ 46,053	$ (7,667)	$ 649,703
Capital expenditures:	$ 4,018	$ 616	$ 1,323	$ 3	$ —	$ 5,960

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. During the Successor Period of 2020, we recorded non-cash ceiling test write-downs on our oil and natural gas properties of $26.1 million pre-tax.
3. Oil and natural gas assets include oil and natural gas properties, saltwater disposal systems, and other non-full cost pool assets.
4. Identifiable assets are those used in Unit's operations in each industry segment.
5. Other corporate assets are principally cash and cash equivalents, short-term investments, transportation equipment, furniture, and equipment.

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS— (Continued)

	Predecessor					
	Eight Months Ended August 31, 2020					
	Oil and Natural Gas	Contract Drilling	Mid-Stream	Corporate and Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 103,443	$ —	$ —	$ —	$ (4)	$ 103,439
Contract drilling	—	73,519	—	—	—	73,519
Gas gathering and processing	—	—	114,531	—	(14,532)	99,999
Total revenues (1)	103,443	73,519	114,531	—	(14,536)	276,957
Expenses:						
Operating costs:						
Oil and natural gas	119,664	—	—	—	(1,973)	117,691
Contract drilling	—	51,811	—	—	(1)	51,810
Gas gathering and processing	—	—	80,607	—	(12,562)	68,045
Total operating costs	119,664	51,811	80,607	—	(14,536)	237,546
Depreciation, depletion, and amortization	68,762	15,544	29,371	1,819	—	115,496
Impairments (2)	393,726	410,126	63,962	—	—	867,814
Total expenses	582,152	477,481	173,940	1,819	(14,536)	1,220,856
Loss on abandonment of assets	17,641	1,092	—	—	—	18,733
General and administrative	—	—	—	42,766	—	42,766
(Gain) loss on disposition of assets	(160)	(1,390)	(18)	1,479	—	(89)
Loss from operations	(496,190)	(403,664)	(59,391)	(46,064)	—	(1,005,309)
Loss on derivatives	—	—	—	(10,704)	—	(10,704)
Write-off of debt issuance costs	—	—	—	(2,426)	—	(2,426)
Reorganization items, net	15,504	(183,664)	(71,016)	373,151	—	133,975
Interest, net	—	—	(1,888)	(20,936)	—	(22,824)
Other	458	1,449	50	77	—	2,034
Income (loss) before income taxes	$ (480,228)	$ (585,879)	$ (132,245)	$ 293,098	$ —	$ (905,254)
Capital expenditures:	$ 5,350	$ 2,438	$ 9,342	$ 83	$ —	$ 17,213

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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. During the Predecessor Period of 2020, we recorded non-cash ceiling test write-downs on our oil and natural gas properties of $393.7 million, pre-tax ($346.6 million, net of tax). Impairment for contract drilling equipment includes a $410.1 million pre-tax write-down for SCR drilling rigs and other drilling equipment. Impairment for mid-stream assets includes a $10.7 million pre-tax write-down for certain long-lived asset groups.
3. Oil and natural gas assets include oil and natural gas properties, saltwater disposal systems, and other non-full cost pool assets.
4. Identifiable assets are those used in Unit's operations in each industry segment.
5. Other corporate assets are principally cash and cash equivalents, short-term investments, transportation equipment, furniture, and equipment.

NOTE 24 – SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Notes of the Predecessor company were registered securities until they were cancelled on the Effective Date. As a result, we are required to present the following condensed consolidating financial information for the Predecessor Periods under to Rule 3-10 of the SEC's Regulation S-X, *Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered.* Our Exit credit agreement is not a registered security. Therefore, the presentation of condensed consolidating financial information is not required for the Successor Period.

For the following footnote:

- we were called "Parent",
- the direct subsidiaries were 100% owned by the Parent and the guarantee was full, unconditional, and joint and several and called "Combined Guarantor Subsidiaries", and
- Superior and its subsidiaries and the Operator were called "Non-Guarantor Subsidiaries."

The following supplemental condensed consolidating financial information reflects the Parent's separate accounts, the combined accounts of the Combined Guarantor Subsidiaries', the combined accounts of the Non-Guarantor Subsidiaries', the combined consolidating adjustments and eliminations, and the Parent's consolidated amounts for the periods indicated.

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS— (Continued)

Condensed Consolidating Statements of Operations

	Predecessor				
	Eight Months Ended August 31, 2020				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 176,962	$ 114,531	$ (14,536)	$ 276,957
Expenses:					
Operating costs	—	171,476	80,607	(14,537)	237,546
Depreciation, depletion, and amortization	1,819	84,306	29,371	—	115,496
Impairments	—	803,852	63,962	—	867,814
Loss on abandonment of assets	—	18,733	—	—	18,733
General and administrative	—	42,766	—	—	42,766
(Gain) loss on disposition of assets	1,479	(1,550)	(18)	—	(89)
Total operating costs	3,298	1,119,583	173,922	(14,537)	1,282,266
Income (loss) from operations	(3,298)	(942,621)	(59,391)	1	(1,005,309)
Interest, net	(20,936)	—	(1,888)	—	(22,824)
Write-off of debt issuance costs	(2,426)	—	—	—	(2,426)
Loss on derivatives	(10,704)	—	—	—	(10,704)
Reorganization items	373,151	(168,160)	(71,016)	—	133,975
Other, net	79	1,906	49	—	2,034
Income (loss) before income taxes	335,866	(1,108,875)	(132,246)	1	(905,254)
Income tax benefit	(14,630)	—	—	—	(14,630)
Equity in net earnings from investment in subsidiaries, net of taxes	(1,241,120)	—	—	1,241,120	—
Net loss	(890,624)	(1,108,875)	(132,246)	1,241,121	(890,624)
Less: net income attributable to non-controlling interest	40,388	—	40,388	(40,388)	40,388
Net loss attributable to Unit Corporation	$ (931,012)	$ (1,108,875)	$ (172,634)	$ 1,281,509	$ (931,012)

Condensed Consolidating Statements of Comprehensive Income (Loss)

	Predecessor				
	Eight Months Ended August 31, 2020				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Net loss	$ (890,624)	$ (1,108,875)	$ (132,246)	$ 1,241,121	$ (890,624)
Other comprehensive loss, net of taxes:					
Unrealized gain on securities, net of tax of $0	—	—	—	—	—
Comprehensive loss	(890,624)	(1,108,875)	(132,246)	1,241,121	(890,624)
Less: Comprehensive income attributable to non-controlling interests	40,388	—	40,388	(40,388)	40,388
Comprehensive loss attributable to Unit Corporation	$ (931,012)	$ (1,108,875)	$ (172,634)	$ 1,281,509	$ (931,012)

Condensed Consolidating Statements of Cash Flows

	Predecessor				
	Eight Months Ended August 31, 2020				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (207,593)	$ 82,769	$ 32,922	$ 136,858	$ 44,956
INVESTING ACTIVITIES:					
Capital expenditures	(986)	(14,585)	(10,204)	—	(25,775)
Producing properties and other acquisitions	—	(382)	—	—	(382)
Proceeds from disposition of assets	1,169	4,772	77	—	6,018
Net cash provided by (used in) investing activities	183	(10,195)	(10,127)	—	(20,139)
FINANCING ACTIVITIES:					
Borrowings under credit agreement, including borrowings under DIP credit facility	55,300	—	32,100	—	87,400
Payments under credit agreement	(31,500)	—	(32,600)	—	(64,100)
DIP financing costs	(990)	—	—	—	(990)
Exit facility financing costs	(3,225)	—	—	—	(3,225)
Intercompany borrowings (advances), net	210,398	(72,642)	(898)	(136,858)	—
Payments on finance leases	—	—	(2,757)	—	(2,757)
Employee taxes paid by withholding shares	(43)	—	—	—	(43)
Bank overdrafts	(7,269)	—	(1,464)	—	(8,733)
Net cash provided by (used in) financing activities	222,671	(72,642)	(5,619)	(136,858)	7,552
Net increase (decrease) in cash and cash equivalents	15,261	(68)	17,176	—	32,369
Cash and cash equivalents, beginning of period	503	68	—	—	571
Cash and cash equivalents, end of period	$ 15,764	$ —	$ 17,176	$ —	$ 32,940

NOTE 25 – FRESH START ACCOUNTING

On the Effective Date, the company qualified for and adopted fresh start accounting under the provisions in FASB Topic ASC 852, *Reorganizations*, as (i) the Reorganization Value of the company's assets immediately before the date of confirmation was less than the post-petition liabilities and allowed claims, and (ii) the holders of the Old Common Stock received less than 50% voting shares of the Successor.

Reorganization Value

Reorganization value, as determined under ASC 820, *Fair Value Measurement*, represents the fair value of the Successor's total assets before the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The reorganization value was derived from the Successor's enterprise value, which represents the estimated fair value of an entity's long-term debt and equity. The Successor's enterprise value, confirmed by the bankruptcy court, was estimated to be within a range of $270.0 million to $380.0 million, with a midpoint of $325.0 million. Based on the estimates and assumptions necessary for fresh start accounting, as further discussed below, the estimated enterprise value was determined to be $317.0 million before consideration of cash and cash equivalents, restricted cash and outstanding debt at the Effective Date. As a result, the reorganization value was determined to be $726.3 million at the Effective Date, as reconciled below.

We estimated the enterprise value of the Successor using three valuation methods: net asset value (NAV), comparable public company analysis, and discounted cash flow (DCF). The NAV is a looking forward methodology under which future cash flows are discounted using various discount rates depending on reserve category. Similarly, DCF projects future cash flows which are discounted at rates above and below the company's estimated weighted average cost of capital. The comparable public company analysis is based on the enterprise values of selected public companies with operating and financial characteristics comparable to the company. Under this methodology, certain financial multiples that measure financial performance and value are calculated for each selected company and then applied to imply an estimated enterprise value of the company.

The following table reconciles the enterprise value to the estimated fair value of the Successor's equity at the Effective Date (in thousands):

Enterprise value	$	559,205
Less: Fair value of noncontrolling interest		(242,200)
Enterprise value of Unit interests		317,005
Plus: Cash and cash equivalents		25,482
Plus: Restricted cash		7,458
Less: Fair value of capital leases		(4,622)
Less: Fair value of debt (including the fair value of current debt)		(148,000)
Fair value of Successor equity	$	197,323

The following table reconciles the enterprise value to the reorganization value of the Successor's assets as of the Effective Date (in thousands):

Enterprise value	$	559,205
Plus: Cash and cash equivalents		25,482
Plus: Restricted cash		7,458
Plus: Current liabilities (excluding the fair value of capital leases and current debt)		86,897
Plus: Long-term asset retirement obligation		22,415
Plus: Other long-term liabilities (excluding long-term asset retirement obligation)		24,886
Reorganization value of Successor assets	$	726,343

Although we believe the assumptions and estimates used to develop the Enterprise Value and the Reorganization Value were reasonable and appropriate, different assumptions and estimates would materially impact the analysis and our resulting conclusions. The assumptions used in estimating these values are inherently uncertain and require significant judgment.

Valuation Process

Oil and Natural Gas Properties

Our oil and natural gas properties are accounted for under the full cost accounting method. We determined the fair value of our oil and gas properties at the Effective Date based on the anticipated cash flows associated with our proved reserves and discounted those cash flows using a weighted average cost of capital rate of 13.5%. The discount rate is commonly based on empirical studies of investment rates of return of publicly traded equity securities with investment return and risk characteristics similar to the subject company, which follows a market-based approach. Weighted average commodity prices used in determining the fair value of oil and natural gas properties were $48.98 per barrel of oil, $2.68 per million cubic feet of natural gas and $18.51 per barrel of oil equivalent of natural gas liquids. Base pricing was derived from an average of forward strip prices. Our unproved acreage was determined to have no value due to the capital constraints contained in our debt agreement along with our plans to not drill in our proved reserves cash flows. Our salt water disposal assets were included in the cash flows of the proved reserves forecast, therefore, those values are included in the total value of our proved properties.

Drilling Equipment

The value of our drilling rigs in operation at the Effective Date (approximately $37.0 million) was estimated using an income-based approach using discounted free cash flows over the remaining useful lives of the drilling rigs. Anticipated cash flows associated with operating drilling rigs were discounted using a weighted average cost of capital rate of 13.8% for five years with a terminal value at the conclusion of the forecast period.

The fair value of our non-operating drilling rigs, and other related drilling equipment at the Effective Date (approximately $26.5 million), was valued using a market-based approach with varying ranges of economic obsolescence rates to adjust for the impact of the oil and gas downturn.

Land and Building

Our corporate headquarters building in Tulsa, Oklahoma was completed in May 2016 and resides on approximately 30 acres. To determine its fair value at the Effective Date, we used a market-based approach based on comparable tenant rates in our area.

Gas Gathering and Processing Equipment, Transportation Equipment, and Other Property

Gas gathering and processing equipment, transportation equipment and other equipment at the Effective Date was valued using a market-based approach estimating what a market participant would pay for similar equipment in an orderly transaction. We used varying ranges of economic obsolescence rates depending on the underlying asset group. For pipelines and right-of-ways, we used a value per acre based on the location of the asset and estimated an average value of $129 per rod. We then applied an economic obsolescence rate of approximately 64% to determine the ultimate fair value.

Unit's Investment in Superior

To determine the net equity value of our investment in Superior at the Effective Date, we simulated paths for Superior's total equity value through the expected liquidation date, where we simulated equity value using a Geometric Brownian Motion (GBM). The expected value (i.e., average of all simulations) of each security class was discounted to present value using the concluded risk-free rate to conclude on the respective allocated values.

Consolidated Balance Sheet

The adjustments included in the following consolidated balance sheets reflect the effect of the transactions contemplated by the Plan (reflected in the column "Reorganization Adjustments") and fair value and other required accounting adjustments resulting from the adoption of fresh start accounting (reflected in the column "Fresh Start Adjustments"). The explanatory notes provide additional information with regard to the adjustments recorded, the methods used to determine the fair values and significant assumptions.

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	As of September 1, 2020					
	Predecessor	Reorganization Adjustments [1]		Fresh Start Adjustments [11]		Successor
ASSETS	(In thousands)					
Current assets:						
Cash and cash equivalents	$ 32,280	$ (6,798)	(2)	$ —		$ 25,482
Restricted cash	—	7,458	(3)	—		7,458
Accounts receivable, net	50,621	—		—		50,621
Materials and supplies	64	—		(64)	(12)	—
Current income tax receivable	850	—		—		850
Prepaid expenses and other	13,692	6,382	(4)	(990)	(13)	19,084
Total current assets	97,507	7,042		(1,054)		103,495
Property and equipment:						
Oil and natural gas properties, on the full cost method:						
Proved properties	6,539,816	—		(6,301,532)	(14)	238,284
Unproved properties not being amortized	30,205	—		(30,205)	(14)	—
Drilling equipment	1,285,024	—		(1,221,566)	(15)	63,458
Gas gathering and processing equipment	833,788	—		(583,690)	(15)	250,098
Saltwater disposal systems	43,541	—		(43,541)	(15)	—
Land and building	59,080	—		(26,445)	(15)	32,635
Transportation equipment	15,577	—		(12,263)	(15)	3,314
Other	57,427	—		(47,469)	(15)	9,958
	8,864,458	—		(8,266,711)		597,747
Less accumulated depreciation, depletion, amortization, and impairment	7,923,868	—		(7,923,868)	(14) (15)	—
Net property and equipment	940,590	—		(342,843)		597,747
Right of use asset	7,476	—		(659)	(16)	6,817
Other assets	24,666	(6,382)	(4)	—		18,284
Total assets	$ 1,070,239	$ 660		$ (344,556)		$ 726,343

	As of September 1, 2020					
LIABILITIES AND SHAREHOLDERS' EQUITY	Predecessor	Reorganization Adjustments (1)		Fresh Start Adjustments (11)		Successor
	(In thousands)					
Current liabilities:						
Accounts payable	$ 27,354	$ 6,382	(4)	$ —		$ 33,736
Accrued liabilities	36,990	(4,115)	(5)	—		32,875
Current operating lease liability	4,643	—		(669)	(16)	3,974
Current portion of long-term debt	124,000	(123,600)	(6)	—		400
Current derivative liabilities	5,089	—		—		5,089
Warrant liability	—	—		885	(17)	885
Current portion of other long-term liabilities	11,201	3,743	(7)	16	(18)	14,960
Total current liabilities	209,277	(117,590)		232		91,919
Long-term debt	16,000	131,600	(6)	—		147,600
Non-current derivative liabilities	766	—		—		766
Operating lease liability	2,760	—		11	(16)	2,771
Other long-term liabilities	61,393	(3,220)	(4) (7)	(14,409)	(18)	43,764
Liabilities subject to compromise	762,215	(762,215)	(8)	—		—
Deferred income taxes	4,466	—		(4,466)	(19)	—
Commitments and contingencies						
Shareholders' equity:						
Predecessor preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued at December 31, 2019	—	—		—		—
Predecessor common stock, $0.20 par value, 175,000,000 shares authorized, 55,443,393 shares issued as of December 31, 2019	10,704	(10,704)	(9)	—		—
Predecessor capital in excess of par value	650,153	(650,153)	(9)	—		—
Successor preferred stock, $0.01 par value, 1,000,000 shares authorized, none issued at September 1, 2020	—	—		—		—
Successor common stock, $0.01 par value, 25,000,000 authorized, 12,000,000 issued at September 1, 2020	—	120	(8)	—		120
Successor capital in excess of par value	—	197,203	(8)	—		197,203
Retained earnings (deficit)	(818,679)	1,215,619	(10)	(396,940)	(20)	—
Total shareholders' equity attributable to Unit Corporation	(157,822)	752,085		(396,940)		197,323
Non-controlling interests in consolidated subsidiaries	171,184	—		71,016	(21)	242,200
Total shareholders' equity	13,362	752,085		(325,924)		439,523
Total liabilities and shareholders' equity	$ 1,070,239	$ 660		$ (344,556)		$ 726,343

Reorganization Adjustments

(1) Reflects accounts recorded as of the Effective Date, including among other items, settlement of the Predecessor's liabilities subject to compromise, cancellation of the Predecessor's equity, issuance of the New Common Stock and the Warrants, repayment of certain of Predecessor's liabilities and settlement with holders of the Notes.

(2) The table below details the company's uses of cash, under the terms of the Plan (in thousands):

unding of the professional fees escrow account	$	(7,458)
roceeds from Exit credit facility		8,000
ayment of debt issuance costs on the Exit credit facility		(3,225)
ayment of professional fees		(3,943)
ayment of accrued interest payable under the Predecessor credit facility		(172)
Changes in cash and cash equivalents	$	(6,798)

(3) Represents the reserve for professional fee escrow of $7.5 million.

(4) Represents the reclassification of other long-term assets related to deferred compensation to prepaid expenses and other assets as the deferred compensation payout must be paid within 12 months from the date of emergence under the Plan. Simultaneously, the current portion of deferred compensation liability was reclassified from other long-term liabilities to accounts payable.

(5) Represents the payment of the DIP facility interest of $0.2 million and professional fees for $3.9 million.

(6) Represents the transition of the DIP Credit Agreement and the Predecessor Credit Agreement of $124.0 million into the Exit Facility and issuing an additional $8.0 million of borrowings under the Exit Credit Agreement.

(7) Represents the reclassification of the short-term portion of the separation benefit liabilities from non-current to current liabilities which was offset by the increase in non-current portion of liabilities.

(8) Settlement of liabilities subject to compromise and the resulting net gain were determined as follows (in thousands):

iabilities subject to compromise before the Effective Date:		
6.625% senior subordinated notes due 2021 (including accrued interest as of the petition date)	$	672,369
Accounts payable		1,179
Employee separation benefit plan obligations		23,394
Litigation settlements		45,000
Royalty suspense accounts payable		20,273
'otal liabilities subject to compromise		762,215
eparation settlement treatment		(6,905)
uccessor Common Stock and APIC[1] issued to allowed claim holders		(175,521)
uccessor Common Stock and APIC for disputed claims reserve		(11,936)
iain on settlement of liabilities subject to compromise	$	567,853

[1] Balance excludes the Successor Common Stock and APIC of $9.9 million to the 5% Equity Facility which was not a liability subject to compromise.

(9) Represents the cancellation of Old Common Stock.

(10) Represents the cumulative impact to Predecessor retained earnings of the reorganization adjustments described above.

Fresh Start Adjustments

(11) Reflects accounts recorded as of the Effective Date for the fresh start adjustments based on the methodologies noted below.

(12) Represents the reclassification of materials and supplies to proved properties.

(13) Represents the write off of the Predecessor's unamortized debt fees related to the DIP facility.

(14) Reflects a decrease of oil and natural gas properties, net, based on the methodology discussed above, and the elimination of accumulated depletion and amortization. The following table summarizes the components of oil and natural gas properties as of the Effective Date:

	Successor Fair Value	Predecessor Historical Book Value
	(In thousands)	
roved properties	$ 238,284	$ 6,539,816
nproved properties	—	30,205
	238,284	6,570,021
ess accumulated depletion, amortization, and impairment	—	(6,305,113)
	$ 238,284	$ 264,908

(15) Reflects a decrease in fair value of drilling equipment, gas gathering and processing equipment, saltwater disposal systems, land and building, transportation equipment, and other property and equipment and the elimination of accumulated depreciation, based on the methodologies discussed above. The following table summarizes the components of other property and equipment as of the Effective Date:

	Successor Fair Value	Predecessor Historical Book Value
	(In thousands)	
rilling equipment	$ 63,458	$ 1,285,024
as gathering and processing equipment	250,098	833,788
altwater disposal systems	—	43,541
and and building	32,635	59,080
ransportation equipment	3,314	15,577
ther	9,958	57,427
	359,463	2,294,437
ess accumulated depreciation and impairment	—	(1,618,754)
	$ 359,463	$ 675,683

(16) Reflects the valuation adjustments to the company's right of use assets, current operating lease liability, and operating lease liability, adjusted for fair value of favorable and unfavorable lease terms, and the revised incremental borrowing rates of the Successor.

(17) Represents the liability for the Warrants using a Black-Scholes-Merton model which uses various market-based inputs including: stock prices, strike price, time to maturity, risk-free rate, annual volatility rate, and annual dividend yield.

(18) Represents the reclassification of the short-term portion of ARO from non-current liabilities to current and the fair value adjustment, which was determined using our fresh start updates to these obligations, including the application of the Successor's credit adjusted risk free rate, which now incorporates a term structure based on the estimated timing of well plugging activity, and resetting all ARO to a single layer.

(19) Represents the adjustments to deferred tax liability as a result of the cumulative tax impact of the fresh start adjustments.

The significant revisions to the carrying value of our assets and liabilities because of applying fresh start accounting resulted in the company increasing its overall net deferred tax asset position on emergence from bankruptcy. Besides the changes in book value, the company has as of the Effective Date, approximately $726.4 million of net operating losses (NOLs) carried forward to offset taxable income in the future years. Approximately $584.2 million of this NOL will expire commencing in fiscal 2021 through 2037. The NOLs of approximately $142.2 million from years ended after December 31, 2017 have an indefinite carryforward period. The amount of these NOLs which is available to offset future income may be severely limited due to change-in-control tax provisions.

Because of our history of operating losses and the uncertainty surrounding the realization of the deferred tax assets in future years, we have determined that it is more likely than not that the deferred tax assets will not be realized in future periods. Accordingly, we recorded a 100% valuation allowance against our net deferred tax assets.

(20) Represents the cumulative impact of the fresh start accounting adjustments discussed above.

(21) The valuation of the non-controlling interest was calculated by taking an income-based approach in valuing Superior. The value of the non-controlling interest was then determined based on a market-based approach for similar type investments, given the contractual rights of the related parties.

Reorganization Items. As described in Note 3 – Summary Of Significant Accounting Policies, our consolidated statements of operations for the year ended December 31, 2021, the four months ended December 31, 2020, and the eight months ended August 31, 2020 include "Reorganization items, net," which reflects gains recognized on the settlement of liabilities subject to compromise and costs and other expenses associated with the Chapter 11 proceedings, primarily professional fees, and the costs associated with the DIP Credit Agreement. These post-petition costs for professional fees, and administrative fees charged by the U.S. trustee, have been reported in "Reorganization items, net" in our consolidated statements of operations as described above. Similar costs were incurred during the pre-petition period have been reported in "General and administrative" expenses.

The following table summarizes the components included in "Reorganization items, net" in our consolidated statements of operations for the periods presented:

	Successor		Predecessor
	Year Ended December 31, 2021	Four Months Ended December 31, 2020	Eight Months Ended August 31, 2020
		(In thousands)	
Gains on settlement of liabilities subject to compromise	$ —	$ —	$ (567,853)
Fresh start accounting adjustments	—	—	401,406
Legal and professional fees and expenses	4,294	2,273	15,745
Acceleration of Predecessor stock compensation expense	—	—	1,431
Exit Facility fees	—	—	3,225
5% Exit Facility equity fee	—	—	9,866
Adjustment to unamortized debt issuance costs associated with the 6.625% senior subordinated notes due 2021	—	—	2,205
Total reorganization items, net	$ 4,294	$ 2,273	$ (133,975)

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 located in the United States.

Capitalized Costs

The capitalized costs as of December 31, 2021 and 2020 were as follows:

	Successor 2021	Successor 2020
	(In thousands)	
Proved properties	$ 225,014	$ 238,581
Unproved properties (wells in progress)	422	1,591
	225,436	240,172
Accumulated depreciation, depletion, amortization, and impairment	(64,966)	(40,806)
Net capitalized costs	$ 160,470	$ 199,366

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

The following table sets forth costs incurred related to our oil and natural gas activities for the periods indicated:

	Successor Year Ended December 31, 2021	Successor Four Months Ended December 31, 2020	Predecessor Eight Months Ended August 31, 2020
		(In thousands)	
Unproved properties acquired	$ 522	$ 26	$ 2,373
Proved properties acquired	—	—	382
Exploration	—	—	—
Development	16,279	3,992	6,440
Asset retirement obligation	478	(1,702)	(29,189)
Total costs incurred	$ 17,279	$ 2,316	$ (19,994)

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 results of operations for producing activities are as follows:

	Successor Year Ended December 31, 2021	Successor Four Months Ended December 31, 2020	Predecessor Eight Months Ended August 31, 2020
	(In thousands)		
Revenues	$ 223,681	$ 55,272	$ 96,033
Production costs	(62,443)	(20,510)	(46,633)
Depreciation, depletion, amortization, and impairment	(24,261)	(40,840)	(461,901)
	136,977	(6,078)	(412,501)
Income tax (expense) benefit	168	128	6,698
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 137,145	$ (5,950)	$ (405,803)

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 were as follows:

	Oil (MBbls)	NGL (MBbls)	Gas (Mcf)	Total (MBoe)
2020				
Proved developed and undeveloped reserves:				
Beginning of year	12,196	23,030	220,187	71,924
Revision of previous estimates [(1)]	(1,909)	(4,477)	(38,901)	(12,870)
Extensions and discoveries	8	13	110	39
Infill reserves in existing proved fields	97	66	452	238
Purchases of minerals in place	62	20	172	112
Production	(2,186)	(3,444)	(37,567)	(11,891)
Sales	(1)	—	(62)	(11)
Net proved reserves at December 31, 2020	8,267	15,208	144,391	47,541
Proved developed reserves, December 31, 2020	8,267	15,208	144,391	47,541
Proved undeveloped reserves, December 31, 2020	—	—	—	—
2021				
Proved developed and undeveloped reserves:				
Beginning of year	8,267	15,208	144,391	47,541
Revision of previous estimates [(2)]	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	—	—	—	—
Production	(1,615)	(2,624)	(29,012)	(9,074)
Sales	(1,215)	(169)	(1,725)	(1,672)
Net proved reserves at December 31, 2021	9,019	21,525	220,640	67,317
Proved developed reserves, December 31, 2021	9,019	21,525	220,640	67,317
Proved undeveloped reserves, December 31, 2021	—	—	—	—

1. Revisions of previous estimates decreased primarily due to the removal of proved undeveloped reserves due to uncertainty regarding our ability to finance the development of our proved undeveloped reserves over a five-year period and from lower commodity prices.
2. 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.

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. SMOG as of December 31, 2021 and 2020 is as follows:

	Successor 2021	Successor 2020
	(In thousands)	
Future cash flows	$ 1,977,529	$ 698,685
Future production costs	(835,430)	(416,095)
Future development costs	—	—
Future income tax expenses	(87,117)	(39)
Future net cash flows	1,054,982	282,551
10% annual discount for estimated timing of cash flows	(483,838)	(89,530)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 571,144	$ 193,021

The principal sources of changes in the standardized measure of discounted future net cash flows were as follows:

	2021	2020
	(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (161,238)	$ (84,163)
Net changes in prices and production costs	334,291	(165,978)
Revisions in quantity estimates and changes in production timing	320,774	(50,979)
Extensions, discoveries, and improved recovery, less related costs	45,019	2,827
Changes in estimated future development costs	—	—
Previously estimated cost incurred during the period	—	—
Purchases of minerals in place	—	852
Sales of minerals in place	(4,161)	(46)
Accretion of discount	19,306	46,203
Net change in income taxes	(87,078)	282
Changes in timing and other	(88,791)	(17,686)
Net change	378,123	(268,688)
Beginning of year	193,021	461,709
End of year	$ 571,144	$ 193,021

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, 2021 future cash flows were computed by applying the unescalated 12-month average prices of $66.56 per barrel for oil, $44.22 per barrel for NGLs, and $3.60 per Mcf for natural gas (then adjusted for price differentials) relating to proved reserves and to the year-end quantities of those reserves. 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, 2021.

Remediation of Previously Reported Material Weaknesses in Internal Control Over Financial Reporting

As disclosed in Part II, Item 9A, Controls and Procedures in our Annual Report on Form 10-K for the year ended December 31, 2020, we determined that a material weakness related to management review controls over complex accounting matters was present. Key elements of effectively designed management review controls include the establishment of documentation standards for process owners to document the substance of their work related to critical accounting estimates, complex accounting matters, and non-routine transactions. Effectively designed management review controls must also have an established process that allows senior accounting personnel having the appropriate knowledge of the subject matter to have enough time to perform effective reviews. Necessary elements for effectively designed management review controls were either not present or not present for a sufficient period of time in order to conclude our disclosure controls and procedures were effective at December 31, 2020.

Management, with oversight from the Audit Committee, developed a remediation plan to address the material weakness and operated new or enhanced processes, procedures, and controls for a sufficient period of time. Specifically, management redesigned certain management review controls related to complex accounting matters, established documentation standards, reassessed the structure of the accounting organization, provided additional training for employees responsible for performing important management review controls, and supplemented internal resources with external expertise when appropriate. Management also hired new personnel and re-assigned certain existing personnel into key positions, and conducted process improvement sessions with third party experts to enhance and augment business processes and utilization of system capabilities for greater effectiveness, efficiency, and scalability. As of December 31, 2021, management concluded that such measures had effectively addressed and resolved the previously identified material weakness.

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, 2021.

Changes in Internal Control Over Financial Reporting

Except as described above, there were no changes in internal control over financial reporting during the quarter ended December 31, 2021, 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 16, 2022, 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	70	Director since September 3, 2020, Chairman since September 8, 2020, President and Chief Executive Officer since October 22, 2020
David P. Dunham	42	Senior Vice President and Chief Operating Officer since October 22, 2020, Senior Vice President of Business Development from August 2017 to October 22, 2020, Vice President of Corporate Planning from January 2012 to August 28, 2017, Director of Corporate Planning from November 2007 to January 2012
Andrew E. Harding	44	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	57	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	44	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.

Mr. Dunham joined Unit in November 2007 as Director of Corporate Planning. In January 2012, he was promoted to the position of Vice President of Corporate Planning. In August 2017, he was promoted to Senior Vice President of Business Development. In October 2020, he was promoted to Senior Vice President and Chief Operating Officer. Prior to Unit, he held positions of increasing responsibility at Williams Power, Leggett & Platt, and Williams Energy Marketing & Trading. Mr. Dunham received his Bachelor of Arts degree in Psychology from Northwestern University, his Master of Science in Finance degree from The University of Tulsa and his Master of Business Administration from The Wharton School of the University of Pennsylvania.

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 16, 2022, 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	64	2020	II		2022	Executive, GBK Corporation, Tulsa, Oklahoma
Alan J. Carr	51	2020	II	Compensation (Chair) Strategic Transactions	2022	Chief Executive Officer, Drivetrain, LLC, New York City, New York
Phil Frohlich	67	2020	II	Audit	2022	Managing Partner, Prescott Capital Management, Tulsa, Oklahoma
Steven B. Hildebrand	67	2008	I	Audit (Chair) Strategic Transactions	2023	Investments, Tulsa, Oklahoma
Philip B. Smith	70	2020	II		2022	President, Chief Executive Officer and Chairman of the Board, Unit Corporation, Tulsa, Oklahoma
Andrei Verona	43	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) and Basic Energy Services (since 2021). 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. 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 and Executive Officer David P. Dunham were Director and Executive Officer, respectively, 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: 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 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' 2021 Compensation

Our board of directors' 2020 compensation was determined by a group of our bondholders during our bankruptcy and the fees remained unchanged for 2021. That group looked at director compensation for companies of a size similar to our reduced post-bankruptcy size to determine recommended director compensation.

Directors' 2021 Cash Compensation

The various components of 2021 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 2021	$65,000 to $85,274

Directors' 2021 Equity Awards

Under the Unit Corporation Long Term Incentive Plan ("LTIP"), we may make annual equity awards to our directors. For information regarding equity awards granted to our non-employee directors during 2021, see the Director Compensation Table. For information regarding equity awards granted to our employee director Mr. Smith during 2021, see the Summary Compensation Table.

Director Compensation Table

The following table shows the total compensation received in 2021 by each of our non-employee directors.

Director Compensation for 2021							
Name [(1)] (a)	Fees Earned or Paid in Cash [(2)] ($) (b)	Stock Awards [(3)] ($) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation ($) (g)	Total ($) (h)
Robert R. Anderson	65,000	234,367	—	—	—	—	299,367
Alan J. Carr	75,274	234,367	—	—	—	—	309,641
Phil Frohlich	75,000	234,367	—	—	—	—	309,367
Steven B. Hildebrand	75,274	234,367	—	—	—	—	309,641
Andrei Verona	85,274	234,367	—	—	—	—	319,641

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 2021 for service on the board or a committee of the board.
3. 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. Represents 18,168 restricted stock units granted to each non-employee director under the LTIP on April 27, 2021, having a grant date fair value of $12.90 per share. These 18,168 restricted stock units represent the total outstanding equity awards at fiscal year-end 2021 for each non-employee director, and they will vest in four equal installments on May 27, 2022, September 3, 2022, September 3, 2023, and September 3, 2024. The outstanding equity awards at fiscal 2021 year-end for our employee director Mr. Smith are set forth in the Outstanding Equity Awards at Fiscal Year-End Table.

Executive Compensation

Overview

The 2021 salaries for Messrs. Dunham and Menefee 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 2021.

Summary Compensation Table for 2021

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

Summary Compensation Table

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	2021	6,500	600	1,374,659	669,089	80,000	2,130,848
	2020	—	—	—	—	26,667	26,667
David P. Dunham, Senior Vice President and COO	2021	350,000	17,500	615,502	361,163	33,698	1,377,863
	2020	318,458	85,270	—	—	34,892	438,620
Christopher K. Menefee, President, Unit Drilling Company	2021	300,000	100,000	571,540	335,365	24,628	1,331,533
	2020	43,750	—	—	—	—	43,750

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 16 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 2021 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
David P. Dunham	—	5,246	11,600	6,000	10,852	33,698
Christopher K. Menefee	—	1,801	11,600	—	11,227	24,628

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 2021

The following table sets forth information about our NEOs' outstanding equity awards at the end of 2021:

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 ($) (d)	Option expiration date (e)	Number of shares or units of stock that have not vested [2] (#) (f)	Market value of shares or units of stock that have not vested [3] ($) (g)
Philip B. Smith	—	58,692	45.00	10/21/2026	51,706	1,670,104
David P. Dunham	—	31,681	45.00	10/21/2026	18,103	584,727
Christopher K. Menefee	—	29,418	45.00	10/21/2026	16,810	542,963

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 is $45.00 per share.
2. The vesting schedule for the restricted stock units that have not vested are as follows for each NEO: For Messrs. Dunham and Menefee, 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.
3. Market value is determined based on the market value of our common stock of $32.30, the quoted closing price of our common stock on the OTC Pink on December 31, 2021, 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 16, 2022, 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	524	523 [1]	1,047
Alan J. Carr	—	—	—
Phil Frohlich [2]	—	—	—
Steven B. Hildebrand	—	—	—
Philip B. Smith	—	—	—
Andrei Verona	—	—	—
David P. Dunham	—	—	—
Christopher K. Menefee	—	—	—
All directors and executive officers as a group (10 people) [3]	524	523	1,047

1. Represents 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, 2022, and 262 shares on May 7, 2022.
2. Mr. Frohlich manages Prescott Group Capital Management, which owns 3,517,707 shares, or approximately 35% of our issued and outstanding shares of common stock as of March 16, 2022, 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 16, 2022.

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	35.10%
RBC Global Asset Management Inc. RBC Centre 155 Wellington Street West, Suite 2300 Toronto, Ontario, Canada M5V 3K7	923,224	9.21%
NYL Investors LLC 51 Madison Avenue New York, New York 10010	623,361	6.22%

1. Beneficial ownership for Prescott Group Capital Management, LLC and RBC Global Asset Management Inc. is as confirmed by the stockholders in March 2022. Information for NYL Investors LLC is based on Schedule 13G filed with the SEC on January 10, 2022. 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 16, 2022.

Securities Authorized for Issuance Under Equity Compensation Plans as of December 31, 2021

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	676,947	45.00	226,279
Total	676,947	45.00	226,279

1. Includes 315,529 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.
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 or a board 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 $2.3 million during 2021 and 2020, respectively, while payments received totaled $6.2 million and $1.9 million during 2021 and 2020, respectively. Payments made to Cactus Drilling Company totaled $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 become 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. The consulting contract has a six-month term, renewing in one-month terms thereafter until formally terminated.

One former director, G. Bailey Peyton IV, also serves as Manager and 99.5% owner of Peyton Royalties, LP, a family-controlled limited partnership that owns royalty rights in wells in several states. The company in the ordinary course of business, paid royalties, or lease bonuses, primarily due to its status as successor in interest to prior transactions and as operator of the wells involved and, sometimes, as lessee, regarding certain wells in which Mr. Peyton, members of Mr. Peyton's family, and Peyton Royalties, LP have an interest. Such payments totaled $0.4 million and $0.2 million during 2021 and 2020, respectively.

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 has determined that all of our directors, except Messrs. Smith, Frohlich, and Anderson are independent under the NYSE standards. The board 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 35% of our issued and outstanding common stock as of March 16, 2022. 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 2021 and 2020. 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	2021	2020
Audit Fees [1]	$909,153	$1,259,347
Audit-Related Fees	—	—
Tax Fees [2]	$21,865	$10,868
All Other Fees	—	—
Total	$931,018	$1,270,215

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. For tax compliance fees.

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, 2021 and 2020
Consolidated Statements of Operations for the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020
Consolidated Statements of Comprehensive Income (Loss) for the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020
Consolidated Statements of Changes in Shareholders' Equity for the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020
Consolidated Statements of Cash Flows for the year ended December 31, 2021, four months ended December 31, 2020, and eight months ended August 31, 2020
Notes to Consolidated Financial Statements

2. *Financial Statement Schedules:*

Included in Part IV of this report for the years ended December 31, 2021 and 2020:

Schedule II—Valuation and Qualifying Accounts and Reserves

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 herewith).
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 herewith).
10.9†	Amendment No. 1 to Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed herewith).
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 herewith).
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	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).
10.16	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).
10.17	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).
10.18	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).

10.19	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).
10.20	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).
10.21	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 herewith).
10.22	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.

Schedule II

UNIT CORPORATION AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Credit Losses:

Description	**Balance at Beginning of Period**	**Additions Charged to Costs & Expenses**	**Deductions & Net Write-Offs**	**Balance at End of Period**
	(In thousands)			
Year ended December 31, 2021	$ 3,783	$ 1,640	$ (2,912)	$ 2,511
Year ended December 31, 2020	$ 2,332	$ 3,155	$ (1,704)	$ 3,783

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 31, 2022

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 31st day of March, 2022.

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

CONSULTING AGREEMENT

THIS CONSULTING AGREEMENT (this "Agreement") is made and entered into by and between Unit Corporation, a Delaware corporation (the "Company") and Robert R. Anderson ("Consultant"), effective on the date this Agreement is signed (the "Effective Date"). The Company and Consultant are sometimes referred to in this Agreement collectively as the "Parties," and each individually as a "Party."

WHEREAS, the Company wishes to engage Consultant to provide certain consulting services to the Company, and Consultant wishes to provide such services, and the Company and Consultant wish to memorialize the terms and conditions of such consulting relationship.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. Engagement; Term. The initial term of Consultant's engagement under this Agreement shall be for the period beginning on the Effective Date and ending on the date that is six (6) months after the Effective Date (the "Initial Term"). Upon the expiration of the Initial Term, and on each date that is one month thereafter, the term of Consultant's engagement under this Agreement shall automatically renew and extend for a period of one (1) month (each such one-month period being a "Renewal Term") unless written notice of non-renewal is delivered by either Party to the other Party not less than five (5) days prior to the expiration of the then-existing Initial Term or Renewal Term, as applicable. The term that Consultant is engaged hereunder is referred to as the "Term."

2. Consulting Services. During the Term, Consultant shall provide such consulting services related to the Company's potential sale of up to all of its oil and gas properties and reserves (the "Consulting Services") as may be reasonably requested of Consultant from time to time by the board of directors of the Company (the "Board"). Consultant will report to the Board's Strategic Transactions Committee on a periodic basis, but no less than once a month. As an independent contractor, Consultant is free to provide services to other entities during the Term as long as Consultant does not violate any of the terms of this Agreement. Consultant shall coordinate the furnishing of his services pursuant to this Agreement with the Company in such a way as to generally conform to the business schedules of the Company, but the method of performance, time of performance, place of performance, hours utilized in such performance, and other details of the manner of performance of Consultant's services hereunder shall be within the sole control of Consultant.

3. Equity Compensation. In consideration of Consultant entering into this Agreement and as an inducement to perform the Consulting Services, the Company shall grant to Consultant certain awards (the "Equity Awards") under the Unit Corporation Long Term Incentive Plan (as amended from time to time, the "Plan"), specifically (a) 7,850 restricted stock units pursuant to the award agreement attached hereto as Annex A (the "RSU Agreement") and (b) 13,416 stock options pursuant to the award agreement attached hereto as Annex B (the "Option Agreement"). The Equity Awards shall be subject to the terms and conditions of the Plan and the RSU Agreement or Option Agreement, as applicable.

4. Termination. The Company or Consultant may terminate this Agreement at any time and for any reason or no reason at all upon ten (10) days' prior written notice to the other Party. This Agreement will automatically terminate upon Consultant's death. In addition, the Company may terminate this Agreement without prior notice for Cause. As used herein, "Cause" shall mean (i) the conviction of a felony or other crime involving moral turpitude; (ii) the commission of any act or omission involving dishonesty, disloyalty or fraud, including with

respect to the Company or any of its affiliates; (iii) reporting to work under the impairment of alcohol or drugs, or the use of illegal drugs (whether or not at the workplace) or other conduct causing the Company or any of its affiliates substantial public disgrace or disrepute or substantial economic harm; (iv) failure to perform all material duties as reasonably directed by the Board; (v) any act or omission aiding or abetting a competitor, supplier or customer of the Company or any of its affiliates whether or not resulting in a disadvantage or detriment to the Company and its affiliates; (vi) breach of any duty, gross negligence, or willful misconduct with respect to the Company or any of its affiliates; or (vii) any other material breach of this Agreement.

5. Independent Contractor. At all times during the Term, Consultant shall be an independent contractor of the Company. In no event shall Consultant be deemed to be an employee of the Company or any of its affiliates, and Consultant shall not at any time be entitled to any employment rights or benefits from the Company or any of its affiliates be deemed to be an agent of the Company or any of its affiliates or have any power to bind or commit the Company or any of its affiliates or otherwise act on their behalf. Consultant acknowledges and agrees that, as a non-employee, Consultant is not eligible for any benefits sponsored by the Company or any of its affiliates. Consultant shall not at any time communicate or represent to any third party, or cause or knowingly permit any third-party to assume, that in performing the Consulting Services hereunder, Consultant is an employee, agent or other representative of the Company or any of its affiliates or has any authority to bind the Company or its affiliates or act on behalf of the Company or its affiliates. Consultant shall be solely responsible for making all applicable tax filings and remittances with respect to amounts paid to Consultant pursuant to this Agreement and shall indemnify and hold harmless the Company and its affiliates, and the foregoing entities' respective representatives for all claims, damages, costs and liabilities arising from Consultant's failure to do so. It is not the purpose or intention of this Agreement or the Parties to create, and the same shall not be construed as creating, any partnership, partnership relation, joint venture, agency, or employment relationship.

6. Governing Law. This Agreement is entered into under, and shall be governed for all purposes by, the laws of the State of Delaware without reference to the principles of conflicts of law thereof. Regarding any claim or dispute related to or arising under this Agreement, Consultant consents to the exclusive jurisdiction, forum and venue of the state and federal courts (as applicable) in Oklahoma. The parties waive, to the fullest extent permitted by law, any defenses to venue and jurisdiction in Oklahoma.

7. Entire Agreement; Amendments. This Agreement together with the RSU Agreement and the Option Agreement constitutes the entire and final agreement between the Parties with respect to the subject matters hereof; provided, however, that nothing herein supersedes or replaces any agreement between Consultant and the Company or any of its affiliates with respect to non-disclosure, confidentiality, non-competition or non-solicitation, as all such agreements will remain in full force and effect. This Agreement may not be amended, supplemented, or otherwise modified except by a written agreement executed by the Parties.

8. Waiver. Any waiver of a provision of this Agreement shall be effective only if it is in a writing signed by the Party entitled to enforce such term and against which such waiver is to be asserted. No delay or omission on the part of either Party in exercising any right or privilege under this Agreement shall operate as a waiver thereof, nor shall any waiver on the part of any Party of any right or privilege under this Agreement operate as a waiver of any other right or privilege under this Agreement nor shall any single or partial exercise of any right or privilege preclude any other or further exercise thereof or the exercise of any other right or privilege under this Agreement.

9. Assignments; Successors. This Agreement is personal to Consultant and, as such, may not be assigned by Consultant. The Company may assign this Agreement without Consultant's consent. Subject to the preceding sentences, this Agreement shall apply to, be

binding in all respects upon and inure to the benefit of the successors and permitted assigns of the Parties.

10. Notices. All notices, requests, demands, claims and other communications permitted or required to be given hereunder must be in writing and shall be deemed duly given and received (a) if personally delivered, when so delivered, (b) if mailed, three business days following the date deposited in the U.S. mail, certified or registered mail, return receipt requested, (c) if sent by e-mail or other form of electronic communication, once transmitted and the confirmation is received, or (d) if sent through an overnight delivery service in circumstances to which such service guarantees next day delivery, the day following being so sent:

If to Consultant, addressed to:

Robert R. Anderson
1363 E 27th Street
Tulsa OK 74114

If to the Company, addressed to:

Unit Corporation
8200 South Unit Drive
Tulsa, Oklahoma 74132
Attn: Vice President, Human Resources

11. Certain Construction Rules. The Section headings contained in this Agreement are for convenience of reference only and shall in no way define, limit, extend or describe the scope or intent of any provisions of this Agreement. Whenever the context may require, any pronoun used in this Agreement shall include the corresponding masculine, feminine or neuter forms, and the singular form of nouns, pronouns and verbs shall include the plural and vice versa. In addition, as used in this Agreement, unless otherwise provided to the contrary, (a) all references to days, months or years shall be deemed references to calendar days, months or years and (b) any reference to a "Section" shall be deemed to refer to a section of this Agreement. The words "hereof", "herein", and "hereunder" and words of similar import referring to this Agreement refer to this Agreement as a whole and not to any particular provision of this Agreement. Unless otherwise specifically provided for herein, the term "or" shall not be deemed to be exclusive, and the term "including" shall not be deemed to limit the language preceding such term.

12. Execution of Agreement. This Agreement may be executed in two or more counterparts, each of which shall be deemed to be an original copy and all of which, when taken together, shall be deemed to constitute one and the same agreement. The exchange of copies of this Agreement and of signature pages by facsimile or e-mail transmission shall constitute effective execution and delivery of this Agreement as to the Parties and may be used in lieu of the original Agreement for all purposes. Signatures of the Parties transmitted by facsimile or e-mail shall be deemed to be their original signatures for all purposes.

13. Tax Withholding. Consultant acknowledges that there may be adverse tax consequences upon the receipt, vesting, exercise or settlement of the Equity Awards or the disposition of shares received following such exercise or settlement and that Consultant has been advised, and hereby is advised, to consult a tax advisor. Consultant represents that Consultant is in no manner relying on the Board, the Company or any of its affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including, without limitation, attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) for tax advice or an assessment of such tax consequences. Consultant shall be solely responsible for making all applicable tax filings and remittances with respect to the Equity

Awards and shall indemnify and hold harmless the Company and its affiliates, and the foregoing entities' respective representatives for all claims, damages, costs and liabilities arising from Consultant's failure to do so

14. Code Section 409A. Notwithstanding anything to the contrary contained herein, this Agreement and the payments hereunder are intended to satisfy or be exempt from the requirements of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), and the Treasury Regulations and other guidance thereunder (collectively, "Section 409A"). Accordingly, all provisions herein, or incorporated by reference herein, shall be construed and interpreted to satisfy or be exempt from the requirements of Section 409A. Further, for purposes of Section 409A, each payment of compensation under this Agreement shall be treated as a separate payment of compensation. Any reimbursement or in-kind benefit provided under this Agreement that constitutes a "deferral of compensation" within the meaning of Section 409A shall be made or provided in accordance with the requirements of Section 409A, including, where applicable, the requirement that (a) any reimbursement is for expenses incurred during the period of time specified in this Agreement, (b) the amount of expenses eligible for reimbursement, or in-kind benefits provided, during a calendar year shall not affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other calendar year, (c) the reimbursement of an eligible expense will be made no later than the last day of the calendar year following the calendar year in which the expense is incurred, and (d) the right to reimbursement or in-kind benefits is not subject to liquidation or exchange for another benefit.

[REMAINDER OF PAGE LEFT BLANK
SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the Parties have duly executed this Consulting Agreement on this __ day of January, 2022, effective for all purposes provided above.

UNIT CORPORATION

By: /s/ Drew Harding
Name: Drew Harding
Title: General Counsel

CONSULTANT

/s/ Robert R. Anderson
Robert R. Anderson

Signature Page to
Consulting Agreement

Annex A

RSU Agreement

[*See attached*.]

<u>Annex B</u>

Option Agreement

[*See attached*.]

AMENDED AND RESTATED SEPARATION BENEFIT PLAN OF UNIT CORPORATION AND PARTICIPATING SUBSIDIARIES

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AMENDED AND RESTATED SEPARATION BENEFIT PLAN OF UNIT CORPORATION AND PARTICIPATING SUBSIDIARIES

INTRODUCTION

The purpose of this Plan is to provide financial assistance to Eligible Employees whose employment has terminated under certain conditions, in consideration of the waiver and release by those employees of any claims arising or alleged to arise from their employment or the termination of employment. No employee is entitled to any payment under this Plan except in exchange for and on the Employing Company's receipt of a written waiver and release given in accordance with the provisions of this Plan.

ARTICLE I
SCOPE

Section 1.1 Name. This Plan shall be known as the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries. The Plan is an "employee benefit plan" governed by the Employee Retirement Income Security Act of 1974, as amended, ("ERISA").

Section 1.2 Plan Year. The Plan Year is the calendar year.

ARTICLE II
DEFINITIONS

"Base Salary" means, as of any Separation from Service, the regular basic cash remuneration before deductions for taxes and other items withheld, and without regard to any salary reduction under any plans maintained by an Employing Company under Sections 401(k) or 125 of the Code, payable to an Employee for services rendered to an Employing Company, but not including pay for bonuses, incentive compensation, special pay, awards or commissions.

"Beneficiary" means the person designated by an Eligible Employee in a written instrument filed with an Employing Company to receive benefits under this Plan.

"Board of Directors" means the board of directors of the Company.

"Change in Control" of the Company shall be deemed to have occurred as of the first day that any one or more of the following conditions shall have been satisfied:

(i) On the close of business on the tenth day following the time the Company learns of the acquisition by any individual entity or group (a "Person"), including any "person" within the meaning of Section 13(d)(3) or 14(d)(2) of the Exchange Act, of beneficial ownership within the meaning of Rule 13d 3 promulgated under the Exchange Act, of 15% or more of either (i) the then outstanding shares of Common Stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding securities of the Company entitled to vote generally in the election of Directors (the "Outstanding Company Voting Securities"); excluding, however, the following: (A) any acquisition directly from the Company (excluding any acquisition resulting from the exercise of an exercise, conversion or exchange privilege unless the security being so exercised, converted or exchanged was acquired directly from the Company); (B) any acquisition by the Company; (C) any acquisition by an employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company; (D) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (iii) of this definition; and (E) if the Board of Directors of the Company determines in good faith that a Person became the beneficial owner of 15% or more of the Outstanding Company Common Stock inadvertently (including, without limitation, because (A) such Person was unaware that it beneficially owned a percentage of Outstanding Company Common Stock that would cause a Change in Control or (B) such Person was aware of the extent of its beneficial ownership of Outstanding Company Common Stock but had no actual knowledge of the consequences of such beneficial ownership under this Plan) and without any intention of changing or influencing control of the Company, then the beneficial ownership of Outstanding Company Common Stock by that Person shall not be deemed to be or to have become a Change in Control for any purposes of this Plan unless and until such Person shall have failed to divest itself, as soon as practicable (as determined, in good faith, by the Board of Directors of the Company), of beneficial ownership of a sufficient number of Outstanding Company Common Stock so that such Person's beneficial ownership of Outstanding Company Common Stock would no longer otherwise qualify as a Change in Control;

(ii) individuals who, as of the date hereof, constitute the Board of Directors (the "Incumbent Board") cease for any reason to constitute at least a majority of such Board; provided that any individual who becomes a Director of the Company subsequent to the date hereof whose election, or nomination for election by the Company's stockholders, was approved by the vote of at least a majority of the Directors then comprising the Incumbent Board shall be deemed a member of the Incumbent Board; and provided further, that any individual who was initially elected as a Director of the Company as a result of an actual or threatened election contest, as such terms are used in Rule 14a-11 of Regulation 14A promulgated under the Exchange Act, or any other actual or threatened solicitation of proxies or consents by or on behalf of any Person other than the Board shall not be deemed a member of the Incumbent Board;

(iii) approval by the stockholders of the company of a reorganization, merger or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Corporate Transaction"); excluding, however, a Corporate Transaction pursuant to which (i) all or substantially all of the individuals or entities who are the beneficial owners, respectively, of the Outstanding Company Common Stock and the Outstanding Company Voting Securities immediately prior to such Corporate Transaction will beneficially own, directly or indirectly, more than 70% of, respectively, the outstanding shares of common stock, and the combined voting power of the outstanding securities of such corporation entitled to vote generally in the election of Directors, as the case may be, of the corporation resulting from such Corporate Transaction (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or indirectly) in substantially the same proportions relative to each other as their ownership, immediately prior to such Corporate Transaction, of the Outstanding Company Common stock and the Outstanding Company Voting Securities, as the case may be, (ii) no Person (other than: the Company; the corporation resulting from such Corporate Transaction; and any Person which beneficially owned, immediately prior to such Corporate Transaction, directly or indirectly, 25% or more of the Outstanding Company Common Stock or the Outstanding Voting Securities, as the case may be) will beneficially own, directly or indirectly, 25% or more of, respectively, the outstanding shares of common stock of the corporation resulting from such Corporate Transaction or the combined voting power of the outstanding securities of such corporation entitled to vote generally in the election of Directors and (iii) individuals who were members of the Incumbent Board will constitute a majority of the members of the Board of Directors of the corporation resulting from such Corporate Transaction; or

(iv) approval by the stockholders of the Company of a plan of complete liquidation or dissolution of the Company.

For the avoidance of doubt, in no event shall the Chapter 11 Cases be deemed a Change in Control for purposes of this Plan.

"**Chapter 11 Cases**" means the chapter 11 cases for the Debtors in the United States Bankruptcy Court for the Southern District of Texas, jointly administered at Case No. 20-32740 (DRJ).

"Code" means the Internal Revenue Code of 1986, as amended from time to time.

"Company" means Unit Corporation, the sponsor of this Plan.

"Comparable Position" means a job with an Employing Company or successor company at the same or higher Base Salary as an Employee's current job and at a work location within reasonable commuting distance from an Employee's home, as determined by the Employee's Employing Company.

"Compensation Committee" means the Committee established and appointed by the Board of Directors or by a committee of the Board of Directors.

"**Debtors**" means Unit, Unit Drilling Company, an Oklahoma corporation, Unit Drilling Colombia, L.L.C., a Delaware limited liability company, Unit Drilling USA Colombia, L.L.C., a Delaware limited liability company, Unit Petroleum Company, an Oklahoma corporation, and 8200 Unit Drive, L.L.C., an Oklahoma limited liability company.

"Discharge for Cause" means termination of the Employee's employment by the Employing Company due to:

(v) the consistent failure of the Employee to perform the Employee's prescribed duties to the Employing Company (other than any such failure resulting from the Employee's incapacity due to physical or mental illness);

(vi) the commission by the Employee of a wrongful act that caused or was reasonably likely to cause damage to the Employing Company;

(vii) the commission by the Employee of unlawful conduct that constitutes sexual harassment or assault of or discrimination against any person;

(viii) an act of gross negligence, fraud, theft, embezzlement, unfair competition, dishonesty or misrepresentation with regard to the Employing Company or on behalf of the Employing Company;

(ix) the conviction of or the entry of a plea of nolo contendere by the Employee to any felony or the conviction of or the entry of a plea of nolo contendere to any offense involving dishonesty, breach of trust or moral turpitude, regardless of whether such crime involves the Employing Company;

(x) a breach of an Employee's fiduciary duty involving personal profit; or

(xi) material violation of any Company policy disclosed and applicable to Employee.

"**Divestiture Employee**" means each Eligible Employee identified in the records of the Company as a member of the team responsible for preparing the Company's oil and gas properties and reserves for sale.

"Eligible Employee" means an Employee who is determined to be eligible to participate in this Plan and receive benefits under Article III, including (i) any employee of the Employing Company whose severance payments and/or benefits did not vest prior to May 22, 2020 pursuant to the Unit Separation Plan, (ii) each Vested Retained Employee and (iii) each Divestiture Employee, MIP Employee, General Employee and SPC/Unit Drilling Employee.

"Employee" means a person who is:

(i) a regular full-time salaried employee of the Employing Company principally employed in the continental United States, Alaska or Hawaii; or

(ii) employed by an Employing Company for work on a regular schedule of at least 20 hours per week for an indefinite period.

"Employee" does not, under any circumstance, mean a person who is:

(i) an employee whose compensation is determined on an hourly basis or who holds a position with the Employing Company that is generally characterized as an "hourly" position;

(ii) an employee who is a member of a bargaining unit unless the employee's union has bargained this Plan pursuant to a current collective bargaining agreement between the Employing Company and the union or the employee's union bargains this Plan pursuant to the bargaining obligations mandated by the National Labor Relations Act; or

(iii) any worker who is retained by an Employing Company and classified as an "independent contractor," "leased employee," or "temporary employee," notwithstanding any reclassification of such person as an "employee" of the Employing Company by a state or federal agency or court of competent jurisdiction.

"Employing Company" means the Company or any subsidiary of the Company electing to participate in this Plan under the provisions of Section 7.1.

"**General Employee**" means each Eligible Employee who is employed by the Company or Unit Petroleum Company except that neither a MIP Employee nor a Divestiture Employee shall qualify as a General Employee.

"Human Resources Director" means the Company's human resources executive.

"MIP Employee" means each Eligible Employee identified in the records of the Company as a participant in the Company's management incentive program initiated in 2021.

"Plan" means the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries, as set forth in this document and as may be amended from time to time.

"Separation and Release Agreement" means the agreement between an Employee and the Employing Company (and the Company if the Employing Company is not the Company) in which the Employee waives and releases the Employing Company and other potentially related parties from certain claims in exchange for and in consideration of payments of the Separation Benefit, to which the Employee would not otherwise be entitled.

"Separation Benefit" means the benefit provided for under this Plan as determined under Article III, including, for the avoidance of doubt, the Vested Minimum Separation Benefit described in Section 3.4, as applicable.

"Separation Period" means the period of time over which an Eligible Employee receives Separation Benefits under the Plan.

"Separation from Service" shall mean an Employee's "separation from service" as determined by the Company in accordance with Section 409A of the Code. A Separation from Service shall be effective on the date specified by the Employing Company (the "Termination Date").

"Specified Employee" means those employees of any Employing Company who are determined by the Compensation Committee to be a "specified employee" in accordance with Section 409A of the Code and the regulations promulgated thereunder.

"SPC/Unit Drilling Employee" means each Eligible Employee who is an employee of SPC Midstream Operating, L.L.C. or Unit Drilling Company except that neither a MIP Employee nor a Divestiture Employee shall qualify as a General Employee.

"Unit Separation Plan" means, collectively, (i) the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries, effective as of September 3, 2020, or (ii) the Amended and Restated Special Separation Benefit Plan of Unit Corporation and Participating Subsidiaries, effective as of September 3, 2020.

"Vested Minimum Separation Benefit" means a benefit equal to thirteen (13) weeks of the Eligible Employee's Base Salary.

"Vested Retained Employee" means any Employee (i) with vested benefits under the Unit Separation Plan as of May 22, 2020 or (ii) whose severance benefits vest under the Unit Separation Plan during the Chapter 11 Cases as a result of termination.

"Years of Service" means the sum of the number (rounded to the nearest whole number) of continuous years of service as an Employee of an Employing Company during the period of employment beginning with the Employee's most recent hire date and ending with the Employee's most recent termination date. For the avoidance of doubt, Years of Service shall include any service performed as an Employee of an Employing Company that occurs prior to the Effective Date.

ARTICLE III
BENEFITS

Section 3.1 Eligibility.

3.1.1 Each Employee who (i) has at least one active Year of Service with an Employing Company immediately before the date of his or her Separation from Service, (ii) complies with all administrative requirements of this Plan, including the provisions of Article V, and (iii) works through his/her Termination Date and is not engaged in a strike or lockout as of the Termination Date, is eligible to participate in this Plan and, subject to all the terms of the Plan, receive benefits as provided in this Article III. An Employee is ineligible to participate in this Plan if that Employee fails to satisfy any of the requirements of this Plan including, but not limited to, failure to establish that his or her termination met the requirements for a Separation from Service.

3.1.2 Additionally, an Employee shall be ineligible to participate in this Plan if that Employee's termination of employment results from:

(i) A Discharge for Cause,

(ii) A court decree or government action or recommendation having an effect on an Employing Company's operations or manpower involving rationing or price control or any other similar type cause beyond the control of an Employing Company,

(iii) Before a Change in Control, an offer to the Employee of a position with an Employing Company, or affiliate, regardless of whether the position offered provides comparable wages and benefits to the position formerly held by the Employee,

(iv) The failure of an Employee to report to work as required by his or her Employing Company,

(v) A temporary work cessation due to strikes, lockouts or similar reasons,

(vi) The divestiture of any business of an Employing Company if the Employee is offered a Comparable Position by the purchaser or successor of such business, an affiliate thereof, or an affiliate of an Employing Company, or

(vii) A termination of the Employee if the Employee is offered a Comparable Position arranged for or secured by an Employing Company.

3.1.3 Notwithstanding anything to the contrary in this Section 3.1, Section 3.1.2(iii), (vi), and (vii) shall not apply to MIP Employees, Divestiture Employees, and General Employees. For the avoidance of doubt, if any member of the aforementioned groups meets the description of Section 3.1.2(iii), (vi), or (vii) above, they will be considered an Eligible Employee under this Article III.

Section 3.2 Separation Benefit. A Separation Benefit shall be provided for Eligible Employees under the provisions of this Article III. Notwithstanding anything to the contrary contained herein, in the event that the Separation from Service is the result of an Eligible Employee's own voluntary action (such as by way of example and not limitation, quitting, resignation or retirement), such Eligible Employee shall not receive payment of any Separation Benefit under the Plan except as set forth in Section 3.4.

Section 3.3 Separation Benefit Amount. The Separation Benefit payable shall be determined according to this Section 3.3, but in no case shall the amount of Separation Benefits exceed the amount permitted under ERISA to maintain this Plan as a welfare benefit plan.

3.3.1 The Separation Benefit payable to a SPC/Unit Drilling Employee shall be equal to two (2) weeks of the SPC/Unit Drilling Employee's Base Salary for each Year of Service; provided that, in any event, the minimum amount of Separation Benefits shall be equal to four (4) weeks of Base Salary and the maximum amount of Separation Benefits shall be equal to thirteen (13) weeks of Base Salary.

3.3.2 The Separation Benefit payable to a MIP Employee shall be equal to four (4) months of the MIP Employee's Base Salary.

3.3.3 The Separation Benefit payable to a Divestiture Employee shall be equal to twelve (12) months of the Divestiture Employee's Base Salary.

3.3.4 The Separation Benefit payment to a General Employee shall be equal to six (6) months of the General Employee's Base Salary.

Section 3.4 Vested Minimum Separation Benefit.

3.4.1 Any Eligible Employee who completes twenty (20) Years of Service before the termination of this Plan shall be vested in such Eligible Employee's Vested Minimum Separation Benefit notwithstanding the subsequent termination of this Plan before such Eligible Employee's Separation from Service. The Vested Minimum Separation Benefit deemed to have vested under this Section 3.4 shall only be payable on the Eligible Employee's Separation from Service if such Separation from Service is as a result of the Eligible Employee's own voluntary action (such as by way of example and not limitation, quitting, resignation or retirement).

3.4.2 If an Eligible Employee does not complete twenty (20) Years of Service before the termination of this Plan or before such Eligible Employee's Separation from Service, and such Eligible Employee experiences a Separation from Service as a result of the Eligible Employee's own voluntary action (such as by way of example and not limitation, quitting, resignation or retirement), then such Eligible Employee shall be ineligible to participate in this Plan and shall not receive any payment of the Vested Minimum Separation Benefit described in this Section 3.4.

3.4.3 For the avoidance of doubt, if an Eligible Employee becomes entitled to receive the Separation Benefit pursuant to Section 3.3, such Eligible Employee shall not receive any payment of the Vested Minimum Separation Benefit described in this Section 3.4.

3.4.4 For the further avoidance of doubt, if an Eligible Employee becomes entitled to receive the Vested Minimum Separation Benefit pursuant to this Section 3.4, such Eligible Employee shall not receive any payment of the Separation Benefit described in Section 3.3.

Section 3.5 Separation Benefit Limitation. The benefits payable under this Plan shall be inclusive of and offset by any amounts paid under federal, state, local or foreign government worker notification (e.g., Worker Adjustment and Retraining Notification Act) or office closing requirements.

Section 3.6 Withholding Tax. The Employing Company shall deduct from the amount of any Separation Benefits payable under this Plan, any amount required to be withheld by the Employing Company by reason of any law or regulation, for the payment of taxes or otherwise to any federal, state, local or foreign government. In determining the amount of any applicable tax, the Employing Company shall be entitled to rely on the number of personal exemptions on the official form(s) filed by the Eligible Employee with the Employing Company for purposes of income tax withholding on regular wages.

Section 3.7 Reemployment of an Eligible Employee. Entitlement to the unpaid balance of any Separation Benefit due to an Eligible Employee under this Plan shall be revoked immediately on reemployment of the person as an Employee of an Employing Company. Any unpaid balance shall not be payable in any future period.

However, if the person's reemployment is subsequently terminated and he or she then becomes entitled to a Separation Benefit under this Plan, Years of Service for the period of re-employment shall be added to that portion of his or her prior service represented by the unpaid balance or the revoked entitlement for the prior Separation Benefit.

Section 3.8 Integration with Disability Benefits. The Separation Benefit payable to an Eligible Employee with respect to any Separation Period shall be reduced (but not below zero) by the amount of any disability benefit payable from any disability plan or program sponsored or contributed to by an Employing Company. The amount of any resulting reduction shall not be paid to the Eligible Employee in any future period.

Section 3.9 Plan Benefit Offset. Except as otherwise provided in the Unit Separation Plan with respect to a Vested Retained Employee, the amount of any severance or separation type payment that an

Employing Company is or was obligated to pay to an Eligible Employee under any law, decree, or court award, because of the Eligible Employee's termination of employment from an Employing Company shall reduce the amount of Separation Benefit otherwise payable under this Plan.

Section 3.10 Recoupment. An Employing Company may deduct from the Separation Benefit any amount owing to an Employing Company from:

(i) the Eligible Employee, or

(ii) the executor or administrator of the Eligible Employee's estate.

ARTICLE IV
METHOD OF PAYMENT

Section 4.1 Separation Benefit Payment. Subject to Section 4.4 of this Plan, the Separation Benefit shall be paid (i) with respect to SPC/Unit Drilling Employees, in substantially equal installments that are equal to, or greater than, the amount of the semi-monthly Base Salary payments (less deductions for taxes and other items withheld) made to an Eligible Employee prior to the Termination Date and such installments shall be paid on the Company's regularly scheduled payroll dates in accordance with Section 5.1 of this Plan or (ii) with respect to MIP Employees, Divestiture Employees and General Employees, in a single lump sum payment on the Company's first regularly scheduled payroll date in accordance with Section 5.1 of this Plan. Notwithstanding anything in the Plan to the contrary, the Separation Period for an SPC/Unit Drilling Employee shall never exceed the amount of time permitted under ERISA to maintain this Plan as a welfare benefit plan. If the Separation Period will expire before the full payment of the Separation Benefit owed to an SPC/Unit Drilling Employees under this Plan, then the total amount unpaid as of the final installment shall be paid to the SPC/Unit Drilling Employee in the final installment.

Section 4.2 Protection of Business.

4.2.1 Any Eligible Employee who receives Separation Benefits under this Plan agrees that, in consideration of the Separation Benefits, the Employee will not, in any capacity, directly or indirectly, and on his or her own behalf or on behalf of any other person or entity, during the period of time he or she is receiving Separation Benefits, either (a) solicit or attempt to induce any current customer of the Employing Company to cease doing business with the Employing Company; (b) solicit or attempt to induce any employee of the Employing Company to sever the employment relationship; (c) compete against the Employing Company; (d) injure the Employing Company and the Company, in their business activities or its reputation; or (e) act as an employee, independent contractor, or service provider of a person or entity that is a competitor of the Employing Company or injures the Employing Company or the Company, its business activities or its reputation (collectively, the "Protection of Business Requirements"). The Compensation Committee in its sole discretion shall decide whether any Eligible Employee is in violation of this Section.

4.2.2 Except as provided in the next paragraph and/or the Separation and Release Agreement, in the event the Eligible Employee violates the Protection of Business Requirements of this Section (or the like provisions of his or her Separation and Release Agreement), the Eligible Employee shall not be entitled to any further payments of Separation Benefits under this Plan and shall be obligated to repay the Employing Company all monies previously received as Separation Benefits from the date of the violation forward.

4.2.3 The Plan shall maintain records for each Eligible Employee that is eligible for Separation Benefits and for each Eligible Employee that actually receives Separation Benefits (including relevant dates, claim records, appeal records, payment amounts, etc.).

4.2.4 The Compensation Committee shall adjudicate claims for denied or terminated Separation Benefits.

4.2.5 The Compensation Committee shall have the ultimate ongoing administrative duty to monitor and investigate the activities of Eligible Employees to ensure they are in compliance with the Protection of Business Requirements. As set forth in this Plan, the Compensation Committee shall have discretion to determine on an ongoing basis whether each Eligible Employee receiving Separation Benefits remains in compliance with the Plan's Protection of Business Requirements during the period the Eligible Employee is receiving Separation Benefits.

4.2.6 The Compensation Committee shall have full and sole discretion to determine eligibility for Separation Benefits and to construe the terms of the Plan.

4.2.7 By accepting Separation Benefits, an Eligible Employee certifies that he/she will comply with the Protection of Business Requirements. Eligible employees must notify the Compensation Committee, through the Human Resources Director, of any change of employer, employment status, or job status or responsibilities, while eligible for Separation Benefits. Additionally, Eligible Employees receiving benefits must complete and submit to the Plan on request a form certifying that they will comply with the Protection of Business Requirements. The Human Resources Director shall review such forms and make preliminary decisions regarding whether the Eligible Employee is in compliance with the Protection of Business Requirements.

4.2.8 As a condition to receiving Separation Benefits or coverage, Eligible Employees and their employers must fully cooperate with any inquiry or investigation by the Compensation Committee (including its authorized representatives) concerning the Protection of Business Requirements. If the Eligible Employee or employer fails to fully cooperate with any such inquiry or investigation, the Eligible Employee shall be deemed to have been in violation of the Protection of Business Requirements, and shall therefore forfeit any further benefits under the Plan and shall be obligated to repay the Employing Company all monies previously received as Separation Benefits.

4.2.9 The Company shall maintain a projection of the amount of money that will be required for the Company to fulfill its unfunded obligation under the Plan to make payments to various Eligible Employees at different times.

Section 4.3 Death.

4.3.1 Separation from Service as a result of death. In the event that the Eligible Employee's Separation from Service is as a result of the Eligible Employee's death, the Eligible Employee's Beneficiary shall be entitled to the applicable Separation Benefit set forth in Section 3.3 of this Plan, subject to Section 5.1 of this Plan. If there is no designated, living Beneficiary, payments shall be paid to the executor or administrator of the Eligible Employee's estate.

4.3.2 Death Subsequent to Separation from Service. In the event that an Eligible Employee's death occurs after the date of Separation from Service, and before receipt of any or all of the benefits to which the Eligible Employee was entitled under this Plan, then the payments shall be made to the Eligible Employee's Beneficiary in accordance with the provisions of Section 3.2 and 4.1, above. If there is no designated living Beneficiary, payments shall be paid to the executor or administrator of the Eligible Employee's estate.

Section 4.4 Payment to Specified Employees Upon Separation from Service. In no event shall a Specified Employee receive a payment under this Plan following a Separation from Service before the first business day of the seventh month following the date of Separation from Service, unless the Separation from Service results from death. Any amounts which would otherwise be payable to the Specified Employee during the six month period may, at the Employing Company's discretion, be accumulated and paid on the first day of the seventh month following the date of the Specified Employee's Separation from Service. For the avoidance of doubt, this Section 4.4 shall not apply if the Employing Company does not have any outstanding securities that are publicly-traded on an established securities market or otherwise at the time that a payment under this Plan becomes payable.

ARTICLE V
WAIVER AND RELEASE OF CLAIMS

Section 5.1 Waiver and Release of Claims. The receipt of the Employee's Separation Benefits shall be subject to the Employee (or in the event of the Employee's death, the Employee's Beneficiary) signing, delivering, and not revoking a Separation and Release Agreement in substantially the form attached to this Plan as Attachment "A" or "B" or such other form as may be designated as the required Separation and Release Agreement from time to time, in the discretion of the Employing Company. The Separation and Release Agreement must be effective and irrevocable within sixty (60) days following the Employee's receipt of such Agreement in accordance with Section 10.8.1 of this Plan. Notwithstanding anything to the contrary herein, the Separation Benefits shall not be payable until after the expiration of any revocation period described herein applicable to the Separation and Release Agreement without the Employee having revoked such Separation and Release Agreement (the "Release Effective Date"). The Separation Benefits shall commence being paid to the Employee on the Company's first payroll date occurring after the Release Effective Date with such first payment to include all payments of the Separation Benefits that would have been made prior to such first payment had the Separation and Release Agreement been effective on the date of the Employee's termination; provided that, in the event that the designated period for signing the Separation and Release Agreement (including the revocation period) spans two (2) tax years of the Employee, the installment payments under Section 4.1 shall automatically commence in the second tax year of the Employee, regardless of when the revocation period expires, provided further that, all Separation Benefits shall be paid in accordance with the requirements of ERISA to maintain this Plan as a welfare benefit plan.

The Separation and Release Agreement is being given in exchange for and in consideration of payment of the Separation Benefit, to which the Employee would not otherwise be entitled. In the event that the Employee (or the Employee's Beneficiary, as applicable) does not sign and deliver the Separation and Release Agreement, or in the event the Employee (or the Employee's Beneficiary, as applicable) revokes the Separation and Release Agreement, the Employee (or the Employee's Beneficiary, as applicable) shall forfeit the Separation Benefits.

In connection with the signing of the Separation and Release Agreement, the following procedures shall be followed (except as modified from time to time, in the discretion of the Employing Company): the Employee (or the Employee's Beneficiary, as applicable) will be advised in writing, by receiving the written text of the Separation and Release Agreement so stating, to consult a lawyer before signing the Separation and Release Agreement; the Employee (or the Employee's Beneficiary, as applicable) will be given either seven (7) days (if Attachment "A" is used), or forty- five (45) days (if Attachment "B" is used) to consider the Separation and Release Agreement before signing. After signing, if the Employee (or the Employee's Beneficiary, as applicable) is over the age of forty (40), such Employee (or the Employee's Beneficiary, as applicable) will have seven (7) days in which to revoke the Separation and Release Agreement, and the Separation and Release Agreement shall not take effect until the seven (7) day revocation period has passed.

In addition, if Attachment "B" is used, the Employee (or the Employee's Beneficiary, as applicable) will be given a written statement identifying for the Employee (or the Employee's Beneficiary, as applicable) the class, unit or group of persons eligible to participate in the Plan and any time limits for eligibility under the Plan, the job titles and ages of all persons eligible or selected for separation under the Plan in the same job classification or organizational unit, and the ages of all persons not eligible or selected for separation under the Plan. The determination of whether the Employee (or the Employee's Beneficiary, as applicable) will be required to sign a Separation and Release Agreement shall be within the sole discretion of the Employing Company.

ARTICLE VI
FUNDING

Section 6.1 Funding. This Plan is an unfunded employee welfare benefit plan under ERISA established by the Company. Benefits payable to Eligible Employees will be paid out of the general assets of Unit Corporation. Unit Corporation shall not be required to establish any special or separate fund or to make any other segregation of assets to assure the payment of any Separation Benefits under this Plan.

ARTICLE VII
OPERATION

Section 7.1 Employing Company Participation. Any subsidiary or affiliate of the Company, at the discretion of the Company, may participate as an Employing Company in the Plan on the following conditions:

(i) Such entity shall make, sign and deliver such instruments as the Company shall deem necessary or desirable;

(ii) Such entity may withdraw from participation as an Employing Company in accordance with Section 7.3, in which event the entity may continue the provisions of this Plan as its own plan, and may thereafter, with respect thereto, exercise all of the rights and powers theretofore reserved to the Company; and

(iii) Any modification or amendment of this Plan made or adopted by the Company shall be deemed to have been accepted by each Employing Company.

Section 7.2 Status of Subsidiaries or Affiliates. The authority of each subsidiary or affiliate to act independently and in accordance with its own best judgment shall not be prejudiced or diminished by its participation in this Plan and at the same time the Employing Companies may act collectively in respect of general administration of this Plan in order to secure administrative economies and maximum uniformity.

Section 7.3 Termination by an Employing Company. Any Employing Company other than the Company may withdraw from participation in the Plan at any time by delivering to the Compensation Committee written notification to that effect signed by the Employing Company's chief executive officer or his delegate. Withdrawal by any Employing Company under this Section or complete discontinuance of Separation Benefits under this Plan by any Employing Company other than the Company, shall constitute termination of this Plan with respect to such Employing Company, but such actions shall not affect any Separation Benefit that has become payable to an Eligible Employee, and such benefit shall continue to be paid in accordance with the Plan provisions in effect at the time of the Separation from Service.

ARTICLE VIII
ADMINISTRATION

Section 8.1 Named Fiduciary. This Plan shall be administered by the Company acting through the Compensation Committee or such other person or committee as may be designated by the Company from time to time. The Compensation Committee shall be the "Administrator" of the Plan and shall be, in its capacity as Administrator, a "Named Fiduciary," as those terms are defined or used in ERISA.

Section 8.2 Fiduciary Responsibilities. The named fiduciary shall fulfill the duties and requirements of a fiduciary under ERISA and is the Plan's agent for service of legal process. The named fiduciary may designate other persons to carry out the fiduciary responsibilities and may cancel any designation. A person may serve in more than one fiduciary or administrative capacity with respect to this Plan. The named fiduciary shall periodically review the performance of the fiduciary responsibilities by each designated person.

Section 8.3 Specific Fiduciary Responsibilities. The Compensation Committee shall be responsible for the general administration and interpretation of the Plan and the proper carrying out of its provisions and shall have full discretion to carry out its duties. In addition to any powers of the Compensation Committee specified elsewhere in this Plan, the Compensation Committee shall have all discretionary powers necessary to discharge its duties under this Plan, including, but not limited to, the following discretionary powers and duties:

(i) To interpret or construe the terms of this Plan, including eligibility to participate, and resolve ambiguities, inconsistencies and omissions;

(ii) To make and enforce such rules and regulations and prescribe the use of the forms as it deems necessary or appropriate for the efficient administration of the Plan;

(iii) To decide all questions concerning this Plan and the eligibility of any person to participate in this Plan; and

(iv) To determine eligibility for benefits under this Plan.

Section 8.4 Allocations and Delegations of Responsibility. The Board of Directors and the Compensation Committee, respectively, shall have the authority to delegate, from time to time, all or any part of its responsibilities under this Plan to those person or persons or committee as it may deem advisable and in the same manner to revoke any such delegation of responsibility. Any action of the delegate in the exercise of such delegated responsibilities shall have the same force and effect for all purposes hereunder as if such action had been taken by the Board of Directors or the Compensation Committee. The Company, the Board of Directors and the Compensation Committee shall not be liable for any acts or omissions of any such delegate. The delegate shall report periodically to the Board of Directors or the Compensation Committee, as applicable, concerning the discharge of the delegated responsibilities.

The Board of Directors and the Compensation Committee, respectively, shall have the authority to allocate, from time to time, all or any part of its responsibilities under this Plan to one or more of its members as it may deem advisable, and in the same manner to remove such allocation of responsibilities. Any action of the member to whom responsibilities are allocated in the exercise of such allocated responsibilities shall have the same force and effect for all purposes hereunder as if such action had been taken by the Board of Directors or the Compensation Committee. The Company, the Board of Directors, and the Compensation Committee shall not be liable for any acts or omissions of such member. The member to whom responsibilities have been allocated shall report periodically to the Board of Directors or the Compensation Committee, as applicable, concerning the discharge of the allocated responsibilities.

Section 8.5 Advisors. The named fiduciary or any person or committee designated by the named fiduciary to carry out fiduciary responsibilities may employ one or more persons to render advice with respect to any responsibility imposed by this Plan.

Section 8.6 Plan Determination. The determination of the Compensation Committee as to any question involving the general administration and interpretation or construction of the Plan shall be within its sole discretion and shall be final, conclusive and binding on all persons, except as otherwise provided herein or by law.

Section 8.7 Modification and Termination. Benefits under this Plan are not vested except as specifically stated otherwise in this Plan document, and may be changed, modified or terminated at any time, either individually or on a Plan-wide basis. The Company may at any time, without notice or consent of any person, terminate or modify this Plan in whole or in part, and such termination or modification shall apply to existing as well as to future employees. However, such actions shall not affect any Separation Benefit that has become payable to an Eligible Employee as a result of that Employee's Separation from Service before the amendment date, and such benefit shall continue to be paid in accordance with the Plan provisions in effect on the date of such Eligible Employee's Separation from Service.

Section 8.8 Indemnification. To the extent permitted by law, the Company shall indemnify and hold harmless the members of the Board of Directors, the Compensation Committee members, and any employee (or committee member) to whom any fiduciary responsibility with respect to this Plan is allocated or delegated to, and against any and all liabilities, costs and expenses incurred by any such person as a result of any act, or omission to act, in connection with the performance of his/her duties, responsibilities and obligations under this Plan, ERISA and other applicable law, other than such liabilities, costs and expenses as may result from the gross negligence or willful misconduct of any such person. The foregoing right of indemnification shall be in addition to any other right to which any such person may be entitled as a matter of law or otherwise. The Company may obtain, pay for and keep current a policy or policies of insurance, insuring the members of the Board of Directors, the Compensation Committee members and any other employees who have any fiduciary responsibility with respect to this Plan from and against any and all liabilities, costs and expenses incurred by any such person as a result of any act, or omission, in connection with the performance of his/her duties, responsibilities and obligations under this Plan and under ERISA.

Section 8.9 Successful Defense. A person who has been wholly successful, on the merits or otherwise, in the defense of a civil or criminal action or proceeding or claim or demand of the character described in Section 8.8 above shall be entitled to indemnification as authorized in Section 8.8.

Section 8.10 Unsuccessful Defense. Except as provided in Section 8.9, any indemnification under Section 8.8, unless ordered by a court of competent jurisdiction, shall be made by the Company only if authorized in the specific case:

8.10.1 By the Board of Directors acting by a quorum consisting of directors who are not parties to such action, proceeding, claim or demand, upon a finding that the member of the Compensation Committee has met the standard of conduct set forth in Section 8.8; or

8.10.2 If a quorum under Section 8.10.1 is not obtainable with due diligence the Board of Directors upon the opinion in writing of independent legal counsel (who may be counsel to any Employing Company) that indemnification is proper in the circumstances because the standard of conduct set forth in Section 8.8 has been met by such member of the Compensation Committee.

Section 8.11 Advance Payments. Expenses incurred in defending a civil or criminal action or proceeding or claim or demand may be paid by the Employing Company, as applicable, in advance of the final disposition of such action or proceeding, claim or demand, if authorized in the manner specified in Section 8.10, except that, in view of the obligation of repayment set forth in Section 8.12, there need be no finding or opinion that the required standard of conduct has been met.

Section 8.12 Repayment of Advance Payments. All expenses incurred, in defending a civil or criminal action or proceeding, claim or demand, which are advanced by the Employing Company, as applicable, under Section 8.11 shall be repaid if the person receiving such advance is ultimately found, under the procedures set forth in this Article VIII, not to be entitled to the extent the expenses so advanced by the Company exceed the indemnification to which he or she is entitled.

Section 8.13 Right of Indemnification. Notwithstanding the failure of the Employing Company, as applicable, to provide indemnification in the manner set forth in Section 8.10 and 8.11, and despite any contrary resolution of the Board of Directors or of the shareholders in the specific case, if the member of the Compensation Committee has met the standard of conduct set forth in Section 8.8, the person made or threatened to be made a party to the action or proceeding or against whom the claim or demand has been made, shall have the legal right to indemnification from the Employing Company, as applicable, as a matter of contract by virtue of this Plan, it being the intention that each such person shall have the right to enforce such right of indemnification against the Employing Company, as applicable, in any court of competent jurisdiction.

ARTICLE IX
EFFECTIVE DATE

Section 9.1 Effective Date. This Plan became effective on September 3, 2020.

ARTICLE X
MISCELLANEOUS

Section 10.1 Assignment. An Employee's right to benefits under this Plan shall not be assigned, transferred, pledged, encumbered in any way or subject to attachment or garnishment, and any attempted assignment, transfer, pledge, encumbrance, attachment, garnishment or other disposition of such benefits shall be null and void and without effect.

Section 10.2 Governing Law. The Plan shall be construed and administered in accordance with ERISA and with the laws of the State of Oklahoma, to the extent such State laws are not preempted by ERISA; provided, however, that notwithstanding the foregoing, should state law apply and not be preempted by ERISA, the non-competition provisions contained in Section 4.2 shall be governed by and construed in accordance with the law of the State of Delaware, without regard to the conflicts of law principles of such state. If any part of the Plan is held by a court of competent jurisdiction to be void or voidable, such holding shall not apply to render void or voidable the provisions of the Plan not encompassed in the court's holding.

Where necessary to maintain the Plan's validity, a court of competent jurisdiction may modify the terms of this Plan to the extent necessary to effectuate its purposes as demonstrated by the terms and conditions stated herein.

Section 10.3 Employing Company Records. The records of the Employing Company with regard to any person's Eligible Employee status, Beneficiary status, employment history, Years of Service and all other relevant matters shall be conclusive for purposes of administration of the Plan.

Section 10.4 Employment Non-Contractual. This Plan is not intended to and does not create a contract of employment, express or implied, and an Employing Company may terminate the employment of any employee with or without cause as freely and with the same effect as if this Plan did not exist. Nothing contained in the Plan shall be deemed to qualify, limit or alter in any manner the Employing Company's sole and complete authority and discretion to establish, regulate, determine or modify at all times, the terms and conditions of employment, including, but not limited to, levels of employment, hours of work, the extent of hiring and employment termination, when and where work shall be done, marketing of its products, or any other matter related to the conduct of its business or the manner in which its business is to be maintained or carried on, in the same manner and to the same extent as if this Plan were not in existence.

Section 10.5 Taxes. Neither an Employing Company nor any fiduciary of this Plan shall be liable for any taxes incurred by an Eligible Employee or Beneficiary for Separation Benefit payments made pursuant to this Plan.

Section 10.6 Binding Effect. This Plan shall be binding on the Employing Company and their successors and assigns, and the Employee, Employee's heirs, executors, administrators and legal representatives. As used in this Plan, the term "successor" shall include any person, firm, corporation or other business entity which at any time, whether by merger, purchase or otherwise, acquires all or substantially all of the assets or business of any Employing Company.

Section 10.7 Entire Agreement. This Plan constitutes the entire understanding between the parties hereto and may be modified only in accordance with the terms of this Plan.

Section 10.8 Decisions and Appeals.

10.8.1 Manner and Content of Benefit Determination.

Within sixty (60) days from the date of an Employee's Separation from Service, the Human Resources Director and the General Counsel shall provide the Employee (or the Employee's Beneficiary, as applicable) with either a Separation and Release Agreement or written or electronic notification of such Employee's ineligibility for or denial of Separation Benefits, either in whole or in part. If at any time the Human Resources Director and the General Counsel make any adverse benefit determination, such notification shall set forth, in a manner calculated to be understood by the Employee including the following:

(i) the specific reason(s) for the adverse determination;

(ii) references to the specific plan provisions upon which the determination is based;

(iii) a description of any additional material or information necessary for the Employee to perfect the claim and an explanation of why such material or information is necessary;

(iv) a description of the Plan's review procedures and the time limits applicable to such procedures, including a statement of the Employee's right to bring a civil action under section 502(a) of ERISA following an adverse benefit determination on review under Section 10.8.3; and

(v) if the Plan utilizes a specific internal rule, guideline, protocol, or other similar criterion in making the determination, either the specific rule, guideline, protocol or other similar criterion; or a statement that such a rule, guideline, protocol or other similar criterion was relied upon and that a copy of such rule, guideline, protocol or similar criterion will be provided free of charge to the Employee upon request.

10.8.2 Appeal of Denied Claim and Review Procedure.

If an Employee does not agree with the reason for the denial or termination of Separation Benefits (including a denial or termination of benefits based on a determination of an Employee's eligibility to participate in the Plan), he/she may file a written appeal within 180 days after the receipt of the original claim determination. The request should state the basis for the disagreement along with any data, questions, or comments he/she thinks are appropriate, and should be sent to the office of the Human Resources Director.

The Compensation Committee, or its designated representatives, shall conduct a full and fair review of the determination. The review shall not defer to the initial determination, and it shall take into account all comments, documents, records and other information submitted by the Eligible Employee without regard to whether such information was previously submitted or considered in the initial determination.

10.8.3 Manner and Content of Notification of Benefit Determination on Review.

Within 60 days of the Compensation Committee's review under Section 10.8.2 above, the Compensation Committee shall provide an Employee with written or electronic notification of any adverse benefit determination on review. The notification shall set forth, in a manner calculated to be understood by the Employee the following:

(i) the specific reason(s) for the adverse determination on review;

(ii) reference to the specific plan provisions upon which the review is based;

(iii) a statement that the Employee is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to his claim for benefits;

(iv) a statement describing any voluntary appeal procedures offered by the Plan and the Employee's right to obtain the information about such procedures, and a statement of the Employee's right to bring an action under section 502(a) of ERISA;

(v) if an internal rule, guideline, protocol, or other similar criterion was relied upon in making the adverse determination on review, either the specific rule, guideline, protocol, or other similar criterion, or a statement that such rule, guideline, protocol, or other similar criterion was relied upon in making the adverse determination on review and that a copy of the rule, guideline, protocol, or other similar criterion will be provided free of charge to the Employee upon request;

(vi) the following statement: "Other voluntary alternative dispute resolution methods, such as mediation, may be available. You may seek additional information by contacting your local U.S. Department of Labor office and your State insurance regulatory agency."

Section 10.9 Section 409A. This Plan is intended to comply with Section 409A of the Code, the Treasury regulations and other guidance promulgated or issued thereunder ("Section 409A"), to the extent the requirements of Section 409A are applicable thereto, and the provisions of this Plan shall be construed in a manner consistent with that intention. Any provision required for compliance with Section 409A that is omitted from this Plan shall be incorporated herein by reference and shall apply retroactively, if necessary, and be deemed a part of this Plan to the same extent as though expressly set forth herein. For purposes of applying the provisions of Section 409A to this Plan, each separately identified amount to which an Employee is entitled under this Plan shall be treated as a separate payment within the meaning of Section 409A. In addition, any series of installment payments under this Plan, including the Separation Benefit, shall be treated as a right to a series of separate payments under Section 409A, including Treas. Reg. Section 1.409A-2(b)(2)(iii).

Neither the Company, nor the Employing Company, shall have any liability to the Employee with respect to the tax obligations that result under any tax law and makes no representation with respect to the tax treatment of payments and/or benefits provided under this Plan.

EXECUTED as of this [●] day of October, 2021.

UNIT CORPORATION

By: /s/ Drew Harding
Drew Harding, General Counsel

To receive a Separation Benefit in connection with a reduction in force or other Termination of Employment affecting an employee, an Eligible Employee must sign the following Separation and Release Agreement "A" provided by the Company:

SEPARATION AND RELEASE AGREEMENT "A"[1]

(Employing Company) ("Unit") and **(Employee Name)** ("Employee" or, "you") hereby agree as follows:

Your employment will end/ended **(Date Employment Ends).**

In consideration for your agreement to the terms and conditions of this Separation and Release Agreement ("Agreement"), Unit will pay you **$_________.00** ("Separation Benefit"), in accordance with and subject to the terms of the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (the "Plan"). You agree to comply with all terms of the plan.

Payments will be paid in substantially equal installments in accordance with the Agreement.

You know that state and federal laws, including the Age Discrimination in Employment Act and Title VII of the Civil Rights Act of 1964, as amended, prohibit employment discrimination based on age, sex, race, color, national origin, religion, handicap, disability, or veteran status, and that these laws are enforced through the United States Equal Employment Opportunity Commission ("EEOC"), United States Department of Labor, and State Human Rights Agencies and courts of competent jurisdiction.

YOU ARE ADVISED TO CONSULT AN ATTORNEY BEFORE SIGNING THIS AGREEMENT.

YOU HAVE SEVEN DAYS AFTER RECEIVING THIS AGREEMENT TO CONSIDER WHETHER TO SIGN THIS AGREEMENT. YOU MAY SIGN THIS AGREEMENT BEFORE EXPIRATION OF THIS PERIOD OF TIME SHOULD YOU CHOOSE TO DO SO.

In exchange for the Separation Benefit described in this Agreement, you agree, on behalf of yourself, your legal representatives, heirs and beneficiaries, to fully and forever relieve, release and discharge Unit, its past, present and future successors, assigns, parent, subsidiaries, operating units, affiliates and divisions (and the agents, representatives, managers, owners, shareholders, officers, directors, employees and attorneys of those entities) (collectively referred to in this Agreement as the "Released Parties"), from all claims, debts, liabilities, demands, obligations, promises, acts, agreements, costs, expenses, damages, actions, and causes of action, whether in law or in equity, whether known or unknown, suspected or unsuspected, arising from your employment with and termination from Unit, as well as any injuries or damages suffered during the course of your employment with Unit, including, but not limited to, any and all claims under Title VII of the Civil Rights Act of 1964 (42 U.S.C. § 2000e, *et seq.),* as amended by the Civil Rights Act of 1991, which prohibits discrimination and/or harassment in employment based on race, color, national origin, religion or sex; the Civil Rights Act of 1966 (42 U.S.C. §1981, 1983 and 1985), which prohibits violations of civil rights; the Age Discrimination in Employment Act of 1967, as amended, (29 U.S.C. §621, *et seq.),* which prohibits age discrimination in employment; Section 510 of the Employment Retirement Income Security Act of 1974, as amended ("ERISA") (29 U.S.C. § 1140), which protects employees from employment discrimination relative to certain employee benefits; the Americans with Disabilities Act of 1990, as amended (42 U.S.C. §12101, *et seq.)* which prohibits discrimination against the disabled; the Family and Medical Leave Act of 1993 (29 U.S.C. §2601, *et seq.),* which provides medical and family leave; the Genetic Information Nondiscrimination Act (42 U.S.C. § 2000ff-10), which prohibits discrimination based on genetic information; Uniformed Services Employment and Re-Employment Rights Act of 1994 (38 U.S.C. §§ 4301 *et seq.),* which prohibits discrimination based on U.S. military service; the Fair Labor Standards Act (42 U.S.C. §201, *et seq.),* including the Wage and Hour Laws relating to payment of wages; claims for Workers' Compensation and any and all other federal, state and local laws and regulations, including claims under applicable state anti-discrimination laws.

[1] NTD: Additional language to be added to release of any employees are employed in California.

X______ Initials A______ Initials

The waiver and release of liability in this Agreement also includes, but is not limited to, a release of the Released Parties by you of any claims for severance pay or severance benefits beyond those specifically set forth in this Agreement, breach of contract, mental pain suffering and anguish, emotional upset, impairment of economic opportunities, unlawful interference with employment rights, defamation, intentional or negligent infliction of emotional distress, fraud, wrongful termination, wrongful discharge in violation of public policy, breach of any express or implied covenant of good faith and fair dealing, that Unit has dealt with you unfairly or in bad faith, and all other common law contract and tort claims.

Nothing in this Agreement, however, releases or diminishes any claims for benefits to which you may be entitled from or under any plan of Unit that is governed by ERISA. Except as described below, you agree and covenant not to file any suit, charge or complaint against the Released Parties in any court or administrative agency, with regard to any claim, demand, liability or obligation arising out of your employment with Unit or separation from Unit. You further represent that no claims, complaints, charges, or other proceedings are pending in any court, administrative agency, commission or other forum relating directly or indirectly to your employment by Unit.

Despite the above provisions or anything else contained in this Agreement to the contrary, this Agreement does not operate to release any claims that may not be released as a matter of law or any claims or rights with respect to the Separation Benefit. Further, this Agreement will not prevent you from doing any of the following:

a. obtaining unemployment compensation, state disability insurance or workers' compensation benefits from the appropriate agency of the state in which you live and work, *provided* you satisfy the legal requirements for those benefits (nothing in this Agreement, however, guarantees or otherwise constitutes a representation of any kind that you are entitled to those benefits);

b. asserting any right that is created or preserved by this Agreement, like your right to receive the Separation Benefit; and

c. filing a charge with or participating in any investigation or proceeding conducted by the EEOC or a comparable state or local agency. Notwithstanding the foregoing, you agree that you are giving up (and hereby do give up) any rights to receive remedial relief (like reinstatement, back pay, or front pay) or monetary damages in any charge, complaint, or lawsuit filed by you or by anyone else on your behalf.

As further consideration for the payment of the Separation Benefit, you agree that you will not, in any capacity directly or indirectly and on your own behalf or on behalf of any other person or entity, during the period of time you are receiving Separation Benefits, either (a) solicit or attempt to induce any current customer of Unit to cease doing business with Unit or (b) solicit or attempt to induce any employee of Unit to sever the employment relationship (collectively, the "Protection of Business Requirements").

Except as provided in the next paragraph, in the event you violate the Protection of Business Requirements, you will not be entitled to any further payments of Separation Benefits under the Plan or this Agreement and you will be obligated to repay Unit all Separation Benefit payments previously received under the Plan and this Agreement.

You agree that you have carefully read and fully understand all the provisions of this Agreement. This is the entire Agreement between you and Unit and is legally binding and enforceable. You agree that you have not relied on any representation or statement, written or oral, not set forth in this Agreement when signing this Agreement.

The parties agree that if a lawsuit relating or pertaining to this Agreement is filed, then the prevailing party will be entitled to collect from the other party the reasonable attorney fees, costs, charges, and expenses it incurs. For purposes of this paragraph, "prevailing party" means the party who has obtained the majority of relief on the disputed claim(s), whether by court order, verdict, or voluntary dismissal (except for in the case of a mutual settlement).

X______
Initials

A______
Initials

This Agreement shall be governed and interpreted under federal law and the laws of the State of Oklahoma, notwithstanding that State's choice of law provisions; provided, however, that notwithstanding the foregoing, should state law apply and not be preempted by ERISA, the non-competition provisions contained in Section 4.2 of the Plan shall be governed by and construed in accordance with the law of the State of Delaware, without regard to the conflicts of law principles of such state. If any part of this Agreement is held by a court of competent jurisdiction to be void or voidable, that holding will not apply to render void or voidable the provisions of this Agreement not encompassed in the court's holding. Where necessary to maintain this Agreement's validity, a court of competent jurisdiction may modify the terms of this Agreement to the extent necessary to effectuate its purposes as demonstrated by the terms and conditions stated in this Agreement.

You knowingly and voluntarily sign this Agreement.

1. You acknowledge receipt of this Agreement on this ___ day of _________, 20____;

X__
(Employee Name)

2. You acknowledge signing and, in signing, consenting to this Agreement on this ___ day of _________, 20____;

X__
(Employee Name)

(Company)

By: __

Date:

X______
Initials

A______
Initials

DESIGNATION OF BENEFICIARY

For Agreement made under the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries

A. Identification	
Participant Name:	**[Employee Name]**
Participant's Social Security Number:	**XXX-XX-_________ (last 4 digits of SS#)**

I hereby designate the following as my beneficiary(ies) entitled to receive any remaining payment(s) of my Separation Benefits that are subject to this Separation and Release Agreement dated ____________ (date employment ended).

B. Information Concerning The Primary Beneficiary(ies):

First name, middle initial, and last name of each beneficiary	Address (including Zip Code) of each beneficiary	Date of Birth	Relationship	*Percentage of Undelivered Benefits
				TOTAL = 100%

[Designation of Beneficiary Continued on Next Page]

X______ Initials

A______ Initials

Contingent Beneficiary(ies) (applicable only if you are not survived by one or more primary beneficiaries)

C. Information Concerning The Contingent Beneficiary(ies):				
First name, middle initial, and last name of each beneficiary	Address (including Zip Code) of each beneficiary	Date of Birth	Relationship	*Percentage of Undelivered Benefits
				TOTAL = 100%

* If no percentages are indicated, benefits will be divided equally between applicable beneficiaries.

It is understood that this Designation of Beneficiary is made under the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries, as amended and restated from time to time and is subject to the terms and conditions stated in that plan, including the beneficiary's survival of my death. If any of those conditions are not satisfied, those rights will transfer according to my will or the laws of descent and distribution.

It is further understood that all prior designations of beneficiary made by me under the plan, if any, with regard to this Separation and Release Agreement are hereby revoked. I reserve the right to change (revoke) this Designation of Beneficiary. Any change of this designation of beneficiary must be in writing, signed by me and filed with the Company before my death.

X__
(Employee Name)

Date

X______
Initials

A______
Initials

To receive a Separation Benefit in connection with a reduction in force or other Termination of Employment affecting a group of employees, an Eligible Employee must sign the following Separation and Release Agreement "B" provided by the Company:

SEPARATION AND RELEASE AGREEMENT "B"[2]

(Company Name) ("Unit") and **(Employee Name)** ("Employee" or, "you") hereby agree as follows:

Your employment will end/ended on **(Date Employment Ended).**

In consideration for your agreement to the terms and conditions of this Separation and Release Agreement ("Agreement"), Unit will pay you **$_________.00** ("Separation Benefit"), in accordance with, and subject to the terms of the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (the "Plan"). You agree to comply with all terms of the Plan.

Payments will be paid in substantially equal installments in accordance with the Agreement.

You know that state and federal laws, including the Age Discrimination in Employment Act and Title VII of the Civil Rights Act of 1964, as amended, prohibit employment discrimination based upon age, sex, race, color, national origin, religion, handicap, disability, or veteran status, and that these laws are enforced through the United States Equal Employment Opportunity Commission ("EEOC"), United States Department of Labor, State Human Rights Agencies and courts of competent jurisdiction.

YOU ARE ADVISED TO CONSULT WITH AN ATTORNEY BEFORE SIGNING THIS AGREEMENT.

YOU HAVE FORTY FIVE DAYS AFTER RECEIVING THIS AGREEMENT, AND THE WRITTEN STATEMENT PROVIDED WITH THIS AGREEMENT, TO CONSIDER WHETHER TO SIGN THIS AGREEMENT. YOU MAY SIGN THIS AGREEMENT BEFORE EXPIRATION OF THIS PERIOD OF TIME SHOULD YOU CHOOSE TO DO SO.

AFTER SIGNING THIS AGREEMENT, YOU HAVE ANOTHER SEVEN DAYS IN WHICH TO REVOKE CONSENT TO THIS AGREEMENT. THIS AGREEMENT DOES NOT TAKE EFFECT UNTIL THOSE SEVEN DAYS HAVE PASSED, AND YOU WILL NOT BE ENTITLED TO ANY BENEFITS UNDER THIS AGREEMENT UNTIL THE REVOCATION PERIOD HAS EXPIRED.

YOU ACKNOWLEDGE THAT, ALONG WITH THIS AGREEMENT, YOU HAVE BEEN GIVEN A WRITTEN STATEMENT: (A) WHICH DESCRIBES THE CLASS, UNIT, OR GROUP OF INDIVIDUALS COVERED BY THE PLAN, ELIGIBILITY FACTORS UNDER THE PLAN, AND ANY TIME LIMITS APPLICABLE TO THE PLAN; AND (B) THE JOB TITLES AND AGES OF ALL INDIVIDUALS ELIGIBLE OR SELECTED FOR TERMINATION UNDER THE PLAN WITH YOU, AND THE AGES AND JOB TITLES OF ALL INDIVIDUALS IN THE SAME JOB CLASSIFICATION OR TITLE AS THOSE EMPLOYEES ELIGIBLE OR SELECTED FOR TERMINATION UNDER THE PLAN WHO ARE NOT ELIGIBLE OR SELECTED FOR TERMINATION.

In exchange for the Separation Benefit, you agree, on behalf of yourself, your legal representatives, heirs and beneficiaries, to fully and forever relieve, release and discharge Unit, its past, present and future successors, assigns, parent, subsidiaries, operating units, affiliates and divisions (and the agents, representatives, managers, owners, shareholders, officers, directors, employees and attorneys of those entities) (collectively referred to in this Agreement as the "Released Parties"), from all claims, debts, liabilities, demands, obligations, promises, acts, agreements, costs, expenses, damages, actions, and causes of action, whether in law or in equity, whether known or unknown, suspected or unsuspected, arising from your employment with and termination from Unit, as well as any injuries or damages suffered during the course of your employment with Unit, including, but not limited to, any and all claims under Title VII of the Civil Rights Act of 1964 (42 U.S.C. § 2000e, *et seq),* as amended by the Civil Rights Act of 1991, which prohibits discrimination and/or harassment in employment based on race, color, national origin, religion or sex; the Civil Rights Act of 1966 (42 U.S.C. §1981, 1983 and 1985), which prohibits violations of civil rights; the Age Discrimination in Employment Act of 1967, as amended, (29 U.S.C. §621, *et seq),* which prohibits age discrimination in employment; Section 510 of the Employment Retirement Income Security Act of 1974, as amended ("ERISA") (29 U.S.C. § 1140), which protects employees from employment discrimination relative to certain employee benefits; the Americans with Disabilities Act of 1990, as amended (42 U.S.C. §12101, *et*

[2] NTD: Additional language to be added to release of any employees are employed in California.

X______ Initials   A______ Initials

seq) which prohibits discrimination against the disabled; the Family and Medical Leave Act of 1993 (29 U.S.C. §2601, *et seq),* which provides medical and family leave; the Genetic Information Nondiscrimination Act (42 U.S.C. § 2000ff-10), which prohibits discrimination based on genetic information; Uniformed Services Employment and Re-Employment Rights Act of 1994 (38 U.S.C. §§ 4301 *et seq),* which prohibits discrimination based on U.S. military service; the Fair Labor Standards Act (42 U.S.C. §201, *et seq),* including the Wage and Hour Laws relating to payment of wages; claims for Workers' Compensation and any and all other federal, state and local laws and regulations, including claims under applicable state anti-discrimination laws.

The waiver and release of liability in this Agreement also includes, but is not limited to, a release of the Released Parties by you of any claims for severance pay or severance benefits beyond those specifically set forth in this Agreement, breach of contract, mental pain suffering and anguish, emotional upset, impairment of economic opportunities, unlawful interference with employment rights, defamation, intentional or negligent infliction of emotional distress, fraud, wrongful termination, wrongful discharge in violation of public policy, breach of any express or implied covenant of good faith and fair dealing, that Unit has dealt with you unfairly or in bad faith, and all other common law contract and tort claims.

Nothing in this Agreement, however, releases or diminishes any claims for benefits to which you may be entitled from or under any plan of Unit that is governed by ERISA. Except as described below, you agree and covenant not to file any suit, charge or complaint against the Released Parties in any court or administrative agency, with regard to any claim, demand, liability or obligation arising out of your employment with Unit or separation from Unit. You further represent that no claims, complaints, charges, or other proceedings are pending in any court, administrative agency, commission or other forum relating directly or indirectly to your employment by Unit.

Despite the above provisions or anything else contained in this Agreement to the contrary, this Agreement does not operate to release any claims that may not be released as a matter of law or any claims or rights with respect to the Separation Benefit. Further, this Agreement will not prevent you from doing any of the following:

a. obtaining unemployment compensation, state disability insurance or workers' compensation benefits from the appropriate agency of the state in which you live and work, *provided* you satisfy the legal requirements for those benefits (nothing in this Agreement, however, guarantees or otherwise constitutes a representation of any kind that you are entitled to those benefits);

b. asserting any right that is created or preserved by this Agreement, like your right to receive the Separation Benefit; and

c. filing a charge with or participating in any investigation or proceeding conducted by the EEOC or a comparable state or local agency. Notwithstanding the foregoing, you agree that you are giving up (and hereby do give up) any rights to receive remedial relief (like reinstatement, back pay, or front pay) or monetary damages in any charge, complaint, or lawsuit filed by you or by anyone else on your behalf.

As further consideration for the payment of the Separation Benefit, you agree that you will not, in any capacity directly or indirectly and on your own behalf or on behalf of any other person or entity, during the period of time you are receiving Separation Benefits, either (a) solicit or attempt to induce any current customer of Unit to cease doing business with Unit or (b) solicit or attempt to induce any employee of Unit to sever the employment relationship (collectively, the "Protection of Business Requirements").

X______ Initials   A______ Initials

Except as provided in the next paragraph, in the event you violate the Protection of Business Requirements, you will not be entitled to any further payments of Separation Benefits under the Plan or this Agreement and you will be obligated to repay Unit all Separation Benefit payments previously received under the Plan and this Agreement.

You agree that you have carefully read and fully understand all the provisions of this Agreement. This is the entire Agreement between you and Unit, and it is legally binding and enforceable. You agree that you have not relied upon any representation or statement, written or oral, not set forth in this Agreement when signing this Agreement.

The parties agree that if a lawsuit relating or pertaining to this Agreement is filed, then the prevailing party will be entitled to collect from the other party the reasonable attorney fees, costs, charges, and expenses it incurs. For purposes of this paragraph, "prevailing party" means the party who has obtained the majority of relief on the disputed claim(s), whether by court order, verdict, or voluntary dismissal (except for in the case of a mutual settlement).

The Plan shall be construed and administered in accordance with ERISA and other federal laws, and with the laws of the State of Oklahoma to the extent that State laws are not preempted by ERISA; provided, however, that notwithstanding the foregoing, should state law apply and not be preempted by ERISA, the non-competition provisions contained in Section 4.2 of the Plan shall be governed by and construed in accordance with the law of the State of Delaware, without regard to the conflicts of law principles of such state. If any part of this Agreement is held by a court of competent jurisdiction to be void or voidable, that holding shall not apply to render void or voidable the provisions of this Agreement not encompassed in the court's holding. Where necessary to maintain this Agreement's validity, a court of competent jurisdiction may modify the terms of this Agreement to the extent necessary to effectuate its purposes as demonstrated by the terms and conditions stated herein.

You knowingly and voluntarily sign this Agreement.

1. You acknowledge receipt of this Agreement on this ___ day of _________, 20____;

X__
(Employee Name)

2. You acknowledge signing and, in signing, consenting to this Agreement on this ___ day of _________, 20____;

X__
(Employee Name)

3. You acknowledge that the seven (7) day revocation period shall end (***Revocation period must be a date which is at least 7 days from the date in paragraph number 2***), and this agreement shall be effective and enforceable as of the ___ day of _________, 20____;

X__
(Employee Name)

(Company Name)

By: __

Date:

X______
Initials

A______
Initials

DESIGNATION OF BENEFICIARY

For agreement made under the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries

A. Identification	
Participant Name:	**[Employee Name]**
Participant's Social Security Number:	**XXX-XX-_________ (last 4 digits of SS#)**

I hereby designate the following as my beneficiary(ies) entitled to receive any remaining payment(s) of my Separation Benefits that are subject to this Separation and Release Agreement dated ____________ (date employment ended).

B. Information Concerning The Primary Beneficiary(ies):				
First name, middle initial, and last name of each beneficiary	Address (including Zip Code) of each beneficiary	Date of Birth	Relationship	*Percentage of Undelivered Benefits
				TOTAL = 100%

[Designation of Beneficiary Continued on Next Page]

X______
Initials

A______
Initials

Contingent Beneficiary(ies) (applicable only if you are not survived by one or more primary beneficiaries)

C. Information Concerning The Contingent Beneficiary(ies):				
First name, middle initial, and last name of each beneficiary	Address (including Zip Code) of each beneficiary	Date of Birth	Relationship	*Percentage of Undelivered Benefits
				TOTAL = 100%

* If no percentages are indicated, benefits will be divided equally between applicable beneficiaries.

It is understood that this Designation of Beneficiary is made under the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries, as amended and restated from time to time and is subject to the terms and conditions stated in that plan, including the beneficiary's survival of my death. If any of those conditions are not satisfied, those rights will transfer according to my will or the laws of descent and distribution.

It is further understood that all prior designations of beneficiary made by me under the plan, if any, with regard to this Separation and Release Agreement are hereby revoked. I reserve the right to change (revoke) this Designation of Beneficiary. Any change of this designation of beneficiary must be in writing, signed by me and filed with the Company before my death.

X__
(Employee Name)

Date

X______ Initials

A______ Initials

AMENDMENT NO. 1 TO
AMENDED AND RESTATED
SEPARATION BENEFIT PLAN OF UNIT CORPORATION AND
PARTICIPATING SUBSIDIARIES

This Amendment No. 1 (this "Amendment") to the Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries dated as of November 1, 2021 (the "Plan"), is adopted, executed and agreed to effective as of March 1, 2022 (the "Amendment Date"), by Unit Corporation, a Delaware corporation ("Unit").

WHEREAS, SPC Midstream Operating, L.L.C. ("SPC Midstream"), a wholly-owned subsidiary of Unit, is an Employing Company as defined in the Plan;

WHEREAS, effective March 1, 2022, the employees of SPC Midstream (the "Transferred Employees") were transferred to Superior Pipeline Company, L.L.C. ("Superior"), a 50/50 joint venture between Unit and SP Midstream Investor, L.L.C. ("JV Partner"); and

WHEREAS, Unit and the JV Partner desire for the Transferred Employees to remain eligible to participate in the Plan;

WHEREAS, the Compensation Committee ("Committee") of the Board of Directors of Unit is the Administrator of the Plan; and

WHEREAS, the Committee has determined that it would be in the best interests of the Company to add Superior as an Employing Company under the Plan and remove SPC Midstream as an Employing Company under the Plan pursuant to this Amendment.

NOW, THEREFORE, in consideration of the foregoing the Plan is hereby amended as follows:

The definition of "SPC/Unit Drilling Employee" contained in Article II of the Plan is hereby deleted in its entirety and replaced with the following:

"SPC/Unit Drilling Employee" means each Eligible Employee who is an employee of Superior Pipeline Company, L.L.C. or Unit Drilling Company except that neither a MIP Employee nor a Divestiture Employee shall qualify as a General Employee.

EXECUTED as of this 9th day of March, 2022.

UNIT CORPORATION

By: /s/ Drew Harding
Drew Harding, General Counsel

Signature Page to Amendment No. 1 to
Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries

AMENDED AND RESTATED

MANAGEMENT SERVICES AND OPERATING AGREEMENT

between

SPC MIDSTREAM OPERATING, L.L.C.

and

SUPERIOR PIPELINE COMPANY, L.L.C.

Dated March 1, 2022

TABLE OF CONTENTS

LIST OF EXHIBITS AND SCHEDULES

EXHIBITS

AMENDED AND RESTATED
MANAGEMENT SERVICES AND OPERATING AGREEMENT

THIS AMENDED AND RESTATED MANAGEMENT SERVICES AND OPERATING AGREEMENT (this "Agreement"), entered into as of March 1, 2022 (the "Effective Date"), is between Superior Pipeline Company, L.L.C., a Delaware limited liability company (the "Company"), and SPC Midstream Operating, L.L.C., an Oklahoma limited liability company ("Operator"). The Company and Operator are sometimes collectively referred to herein as the "Parties" and each, individually, as a "Party."

Recitals:

A. The Company and its subsidiaries, including Superior Appalachian Pipeline, L.L.C., Superior Pipeline Texas, L.L.C., Preston County Gas Gatheri L.L.C., and Superior Pipeline Kansas, L.L.C. (collectively, the "Superior Companies"), own gathering, processing, treating, compression, dehydration, transportation and other related facilities for natural gas and natural gas liquids.

B. Unit Corporation, a Delaware corporation ("Unit"), and SP Investor Holdings, LLC ("Investor Holdco Party") entered into that certain Second Amended and Restated Limited Liability Company Agreement of the Company, dated as of July 1, 2019 (such agreement, as it may be amended, modified o supplemented from time to time, the "LLC Agreement"), to govern the management, ownership, and operation of the Company.

C. The Parties previously entered into that certain Management Services and Operating Agreement dated as of April 3, 2018 (the "Original Agreement").

D. The Parties desire to enter into this Agreement in order to amend and restate the Original Agreement in its entirety.

NOW, THEREFORE, for and in consideration of the foregoing and other good and valuable consideration, the Company and Operator agree as follows:

Article 1
Defined Terms; Construction

1.1 Defined Terms. As used in this Agreement, the capitalized terms set forth below shall have these meanings:

"Affiliate" means, regarding any Person, any other Person that, directly or indirectly, Controls, is Controlled by, or is under common Control with, such Person. For this Agreement, the Company and Operator are not to be considered Affiliates of each other, and the Company is not to be considered an Affiliate o Unit or Investor Holdco Party.

"Agreed Interest Rate" means for any day a per annum rate of interest equal to (i) the "prime rate," as published in the "Money Rates" column of The Wal Street Journal, from time to time, or (ii) if such rate is no longer available, the average of the prime interest rates announced, from time to time, by the three largest banks (by assets) headquartered in the United States which publish a prime, base or reference rate (or, if such rate is contrary to any applicable usury Law, the maximum rate permitted by such applicable Law). The Agreed Interest Rate shall change effective as of the date of any change as published in The Wall Street Journal, or as established by banks regarding the rate in clause (ii) as appropriate, but will not exceed the maximum rate permitted by applicable Law.

"Agreement" is defined in the introductory paragraph.

"Audit" is defined in Section 11.2.

"Business Day" means any day other than a Saturday, a Sunday, or a day on which national banking associations in any of the States of Texas, Oklahoma or New York are required or authorized by applicable Law to remain closed.

"Calendar Month" means any calendar month.

"Closing Date" means April 3, 2018.

"Company" is defined in the introductory paragraph.

"Company Assets" means assets (including all pipelines, facilities, and equipment), rights of way, easements and any other rights and interests owned by the Superior Companies as of the Effective Date, together with any other pipelines, facilities, equipment, or other assets acquired, constructed, or developed by the Superior Companies after the Effective Date, but excluding any assets sold or disposed of by the Superior Companies.

"Company Bank Accounts" is defined in Section **Error! Reference source not found.**.

"Company Business" is defined in the LLC Agreement.

"Company Indemnified Parties" is defined in Section 7.1(c).

"Company Revenues" is defined in Section **Error! Reference source not found.**.

"Confidential Information" is defined in Section 12.8(a).

"Contract" is defined in the LLC Agreement.

"Control" and "Controlled" are defined in the LLC Agreement.

"Dispute" means any dispute, controversy or claim (of any and every kind or type, whether based on Contract, tort, statute, regulation or otherwise) arising out of, relating to or connected with this Agreement or the transactions contemplated hereby, including any dispute, controversy or claim about the existence, validity, interpretation, performance, breach or termination of this Agreement or the relationship of the Parties arising out of this Agreement or the transactions contemplated hereby.

"Executive Negotiation Notice" is defined in Section 9.1.

"Force Majeure" is defined in Section 12.15(a).

"GAAP" means United States generally accepted accounting principles, consistently applied, as in effect from time to time.

"Governmental Authority" means any federal, state, provincial, or local government or governmental regulatory body and any of their respective subdivisions, agencies, instrumentalities, authorities, or tribunals.

"Governmental Authorization" means any authorization, approval, consent, franchise, license, covenant, order, ruling, permit, certification, exemption, notice, declaration or similar right, undertaking or other action of, to or by, or any filing, qualification or registration with, any Governmental Authority.

"Indemnified Party" means the Company Indemnified Parties or the Operator Indemnified Parties.

"Indemnifying Party" means the Company or the Operator.

"Investor Holdco Party" is defined in the Recitals.

"IP" is defined in Section 12.14.

"Law" means any law, statute, rule (including common law rules), Order, ordinance, code, regulation or other legally enforceable requirement of any Governmental Authority, including the foregoing relating to protecting the environment and/or human health and safety.

"Liabilities" means any claims, causes of actions, payments, charges, judgments, assessments, liabilities, losses, damages, penalties, fines or costs and expenses, including any reasonable fees of attorneys, experts, consultants, accountants and other professional representatives and legal or other expenses incurred in connection therewith and including liabilities, costs, losses and damages for personal injury, illness or death, property damage, Contract claims, torts or otherwise.

"LLC Agreement" is defined in the Recitals.

"Members" means, collectively, Unit and Investor Holdco Party and/or their successors and assigns, and "Member" means any one of the foregoing.

"Membership Interests" is defined in the LLC Agreement.

"Notice Party" is defined in Section 5.4(b).

"Operating Fee" means $250,000 per Calendar Month, as adjusted from time to time under Section 5.4, which is payable by the Company to Operator for performing the Services.

"Operating Fee Adjustment Event" is defined in Section 5.4(b).

"Operator" is defined in the introductory paragraph.

"Operator Bankruptcy Event" is defined in Section 8.2(e).

"Operator Indemnified Parties" is defined in Section 7.2.

"Order" means any order, judgment, injunction, ruling, or decree of any court or other Governmental Authority.

"Original Agreement" is defined in the Recitals.

"Parties" and "Party" are defined in the introductory paragraph.

"Person" means any individual, corporation, company, partnership, limited partnership, limited liability company, trust, estate, Governmental Authority or any other entity.

"Products" means crude oil, water, natural gas and natural gas liquids that may be gathered, processed, transported, treated or handled by or on the Company Assets.

"Receiving Party" is defined in Section 5.4(b).

"Representatives" means, regarding any Person, such Person's officers, employees, agents, accountants, attorneys, consultants and other authorized representatives.

"Services" means those Services set forth in Exhibit A.

"Successor Operator" is defined in Section 8.3(b).

"Superior Companies" is defined in the Recitals.

"Term" is defined in Section 8.1.

"Third Party" means any Person that is not Operator, the Company, a Member or an Affiliate of the foregoing.

"Unit" is defined in the Recitals.

1.2 References and Rules of Construction All references in this Agreement to Exhibits, Schedules, Articles, Sections, subsections and other subdivisions refer to the corresponding Exhibits, Schedules, Articles, Sections, subsections and other subdivisions of or to this Agreement unless provided otherwise. Titles appearing at the beginning of any Articles, Sections, subsections, and other subdivisions of this Agreement are for convenience only, constitute no part of this Agreement, and shall be disregarded in construing the language hereof. The words "this Agreement," "herein," "hereby," "hereunder" and "hereof," and words of similar import, refer to this Agreement as a whole and not to any particular Article, Section, subsection or other subdivision unless expressly so limited. The words "this Article," "this Section" and "this subsection," and words of similar import, refer only to the Article, Section, or subsection hereof in which such words occur. The word "including" (in its various forms) means "including without limitation." All references to "$" or "dollars" shall be deemed references to United States Dollars. Each accounting term not defined herein will have the meaning given to it under GAAP. Pronouns in masculine, feminine or neuter gender shall be construed to state and include any other gender, and words, terms and titles (including terms defined) in the singular form shall be construed to include the plural and vice versa, unless the context otherwise requires. Schedules and Exhibits referred to herein are attached to and by this reference incorporated for all purposes. References to any Law or agreement shall mean such Law or agreement as it may be amended from time to time. All references herein to matters that require the "approval of the Company" or similar statements mean the approval of the Company as provided in the LLC Agreement.

Article 2
Engagement of Operator

The Company engages Operator to perform the Services under the terms of this Agreement. Operator accepts such engagement and agrees to perform or cause to be performed, the Services under the terms, and subject to the limitations, set forth in this Agreement.

Article 3
Services

3.1 Services. Subject to the terms of this Agreement, Operator shall perform, or cause to be performed, and Company retains Operator to perform or cause to be performed, its obligations hereunder and the Services. For the avoidance of doubt, the Services may be provided by Affiliates of Operator.

3.2 Company. Subject to the terms of this Agreement (including Article 4, Section 6.1 and Section 7.1), the Company: (a) authorizes and directs Operator to perform, or cause to be performed, any acts and things necessary, requisite or proper in connection with performing the Services contemplated by this Agreement; (b) shall provide to Operator, and/or cooperate with Operator to obtain, any documents and other instruments reasonably necessary for Operator to perform, or cause to be performed, the Services contemplated under this Agreement; and (c) shall provide Operator with access to the Company Assets as necessary for Operator to perform, or cause to be performed, the Services contemplated under this Agreement.

3.3 Independent Contractor. In performing any Services by Operator for the Company, Operator shall be conclusively deemed to be an independent contractor. The Company shall have no right or authority to supervise or instruct the Representatives of Operator in regards to the daily performance of any Services or the specifics of how such services are to be provided, and such Representatives shall be under the direct and sole supervision and control of Operator. The Parties do not intend to create, nor shall this Agreement be deemed or construed to create, a partnership, joint venture, association or trust. This Agreement shall not be deemed or construed to authorize any Party to act as an agent, servant or employee for any other Party for any purpose except as explicitly set forth in this Agreement. In their relations with each other under this Agreement, the Parties shall not be fiduciaries.

Article 4
Performance of Services

4.1 Personnel. Operator shall provide enough personnel to staff and perform the Services, which may be accomplished to the extent reasonably necessary by (a) employees of

Operator, (b) employees Affiliates of Operator, or (c) Third Party contractors hired by Operator. All personnel engaged or directed by Operator to perform Operator's obligations under this Agreement shall be duly qualified and experienced to perform such obligations. Operator shall cause its employees and the employees of its Affiliates performing Services to be properly trained and to comply with all Laws applicable to the Company Assets. Operator shall use commercially reasonable efforts to cause Third Party contractors to perform the Services using properly trained personnel and in compliance with all Laws. Notwithstanding the use by Operator of any Affiliates in its performance of the Services, Operator will, in all instances, remain primarily responsible for performing the Services under this Agreement.

Article 5
Fees; Revenues; Costs

5.1 Operating Fee. Each Calendar Month, the Company shall pay Operator (by wire transfer or other electronic means) the Operating Fee. Th Operating Fee for a Calendar Month shall be payable by the Company on the Business Day immediately preceding the 20th day of the following Calendar Montl An invoice from Operator to the Company shall not be required for the Company to pay Operator each Calendar Month for the Operating Fee. The Operatin Fee covers all costs relating to the Services. The Parties acknowledge that, other than the Operating Fee, Operator is not entitled to recover from the Compan any other amounts arising from or in connection with its provision of the Services.

5.2 Payment of Costs. The Company agrees to pay all costs permitted to be incurred by Operator under the terms of this Agreement to the exten actually incurred in the performance of the Services.

5.3 Objections to Invoices; Late Payments; and Disputed Payments. Regarding all invoices (including the Monthly Statement), the Company shal endeavor to notify Operator in writing of any objections to all or any portion of such invoices within 60 days following the date any such invoices are submitted to the Company. Payment of all or any portion of an invoice or notice shall not be construed as a waiver of any right under this Agreement by the Company. If any payment is not made in accordance with the terms of this Article 5, any portion of the unpaid balance that is not subject to a good faith Dispute shall bear interest from the date due at the Agreed Interest Rate. Any Disputes between Company and Operator as to the payment of any amounts under this Agreement shall be resolved in accordance with the Dispute resolution procedures set forth in Article 9. Payments of all amounts due as a result of utilizing the Dispute resolution procedures set forth in Article 9 will be paid by the appropriate Party within 5 Business Days of the date of final resolution of such Dispute, and such payments shall include (a) the final amount due as determined under Article 9, plus (b) the Agreed Interest Rate.

5.4 Operating Fee Escalation.

(a) The Operating Fee shall be escalated on each January 1st, commencing on January 1, 2019, according to the greater of 1% or (i) the percentage year-over-year change in the Gross Domestic Product implicit price deflator for final sales to domestic purchasers in the Gross Domestic Product, 4th Quarter (final) report published by the U.S. Department of Commerce, Bureau of Economic Analysis, or (ii) if such index is discontinued, then such index as the Parties may reasonably agree. The Gross Domestic Product implicit price deflator for final sales to domestic purchasers shall be derived by subtracting one from the quotient calculated by dividing the index level for the most recently reported time period by the index level for the time one year prior to the most recently reported time period.

(b) On or after an Operating Fee Adjustment Event, either Party (the "Notice Party") may give the other Party (the "Receiving Party") 20 Business Days' notice of a proposed new Operating Fee ("New Operating Fee") which shall reflect an increase or reduction in the Operating Fee proportionate to the increase or reduction, as applicable, in expenses Operator will incur to provide the Shared Services following the Operating Fee Adjustment Event. Within the 20 Business Day period from the date the Receiving Party receives such notice, the Receiving Party shall give notice to the Notice Party of the Receiving Party's election to accept or reject the New Operating Fee. The term "Operating Fee Adjustment Event" means any event that is reasonably expected to materially affect the cost or scope of the Shared Services to the Company.

Article 6
Representations and Warranties; Claims

6.1 Representations and Warranties. Each Party represents and warrants to the other Party as to itself, that, as of the date hereof:

(a) it is duly organized and validly existing under the Laws of its jurisdiction of organization, it is qualified to transact business and is in good standing in each jurisdiction in which such qualification is required by Law, and has all requisite power and authority to own its property and assets and conduct its business as presently conducted or proposed to be conducted under this Agreement;

(b) it has the power and authority to execute and deliver this Agreement and to perform its obligations hereunder;

(c) it has taken all necessary action to authorize the execution, delivery and performance of this Agreement, and this Agreement has been duly executed and delivered, and constitutes the valid, legal and binding obligation of such Party enforceable against it under its terms except as such enforcement may be limited by bankruptcy, insolvency, moratorium or similar Laws affecting the rights of creditors or by general equitable principles (whether considered in a proceeding in equity or at law);

(d) no Governmental Authorization is required for (i) the valid execution and delivery of this Agreement or (ii) the performance by such Party of its obligations under this Agreement except such Governmental Authorization as has been duly obtained or made;

(e) the execution or delivery of this Agreement, the performance by such Party of its obligations for the transactions contemplated hereby and fulfilling the terms hereof, in each case, does not and will not: (i) conflict with or violate any provision of its organizational documents, (ii) conflict with, violate or result in a breach of any Law currently in effect, or (iii) conflict with, violate or result in a breach of, or constitute a default under or result in the imposition or creation of, any lien under any agreement or instrument to which it is a party or by which it or any of its properties or assets are bound;

(f) no meeting has been convened for its dissolution or winding-up, no such step is intended by it and, so far as it is aware, no petition, application or the like is outstanding or threatened for its dissolution or winding-up;

(g) there are no bankruptcy, reorganization, receivership or arrangement proceedings pending, being contemplated by, or threatened against it; and

(h) it is not a party to any legal, administrative, arbitral or other proceeding, investigation or controversy pending, or, to the best knowledge of such Party, threatened, that would adversely affect such Party's ability to perform its obligations under this Agreement.

6.2 Claims. Operator shall have no authority to settle any claim or demand made on behalf of or against the Superior Companies or related to the Company Assets unless Operator first receives the written approval of the Company if such settlement of claim or demand requires approval of the Board under the LLC Agreement.

Article 7
Standard of Performance, Indemnity, and Insurance

7.1 Standard of Conduct; Waiver; Indemnification by Operator.

(a) The Operator shall perform, or cause to be performed, the Services in a good and workmanlike and commercially reasonable manner, generally consistent with operating practices used by Operator in its operation of similar assets owned or operated by Operator or its Affiliates, and shall conduct itself with that degree of care, diligence, and skill of a reasonable prudent operator consistent with industry-standard practices in the natural gas pipeline gathering and transportation industry. In providing the Services, Operator shall comply with all applicable Laws.

(b) Operator shall have no Liability to the Superior Companies or their Affiliates and each of such Person's equity holders, partners, members, directors, officers, operators, employees, agents and representatives for losses sustained or Liabilities in the performance of the Services, except for Liabilities that result from (i) Operator's gross negligence, or (ii) Operator's actual fraud or willful misconduct.

(c) Operator is responsible for, shall pay on a current basis, and agrees to defend, indemnify and hold harmless each of the Superior Companies, their Affiliates, and each of such Person's equity holders, partners, members, directors, officers, operators, employees, agents and representatives (collectively, "Company Indemnified Parties") against any Liabilities, whether asserted by any Third Party or otherwise, to the extent arising from, based upon, or related to Operator's gross negligence, actual fraud or willful misconduct.

(d) THE TOTAL AGGREGATE LIABILITY OF THE OPERATOR TO THE COMPANY FOR ALL LIABILITY ARISING (OR IN CONNECTION WITH THE PERFORMANCE OF SERVICES UNDER THIS AGREEMENT SHALL NOT EXCEED $1 EXCEPT TO THE EXTENT THAT ANY SUCH LIABILITY ARISES FROM OR IN CONNECTION WITH OPERATOR'S ACTUA OR WILLFUL MISCONDUCT THAT IS DONE WITH THE INTENTION TO CAUSE HARM TO THE SUPERIOR COMPANIES.

7.2 Indemnification by the Company. The Company is responsible for, shall pay on a current basis, and agrees to defend, indemnify and hold harmless Operator, its Affiliates and each of such Person's equity holders, partners, managers, members, directors, officers, employees, agents and representatives (collectively, the "Operator Indemnified Parties") against any Liabilities, whether asserted by any Third Party or otherwise, to the extent arising from, based upon or related to the provision of the Services , including (a) Liabilities resulting from, arising out or connected with the operation, maintenance, or development of the Company Assets or performing this Agreement or the Services provided by Operator, (b) any loss of or damage to equipment or property of the Company Indemnified Parties, the Operator Indemnified Parties, or any Third Party, (c) any damage or losses to the Company Assets, and (d) Liabilities connected wit Products (including the quality, use, or condition of such Products), both prior to such Products' receipt into the Company Assets and after delivery of such Products (including losses or shrinkage of such Products during their transportation in the Company Assets), IN EACH CASE, EVEN IF SUCH LIABILIT ARE BASED UPON THE NEGLIGENCE (WHETHER JOINT, CONCURRENT, ACTIVE, OR PASSIVE) OF ANY OF THE OI INDEMNIFIED PARTIES OR UPON CONDITIONS, ACTS OR OMISSIONS (WHETHER OR NOT THE RESPONSIBILITY OF AN OPERATOR INDEMNIFIED PARTIES) THAT IMPOSE STRICT LIABILITY ON ANY OF THE OPERATOR INDEMNIFIED PARTIES, OTHER FAULT OR RESPONSIBILITY OF ANY OF THE OPERATOR INDEMNIFIED PARTIES; *PROVIDED, HOWEVER*, THAT THE ABOV INDEMNITY CONTAINED IN THIS SECTION 7.2 SHALL NOT APPLY TO THE EXTENT OPERATOR IS OBLIGATED TO INDEMNIFY COMPANY INDEMNIFIED PARTIES PURSUANT TO SECTION 7.1.

7.3 Waiver of Liabilities. Notwithstanding anything herein to the contrary, none of the Company Indemnified Parties and none of the Operator Indemnified Parties may recover from the Company or Operator, or their respective Affiliates, any indirect, consequential, punitive or exemplary damages or damages for lost profits of any kind arising under or in connection with this Agreement or the transactions contemplated hereby, except to the extent any such Party suffers such damages to a Third Party, which damages (including costs of defense and reasonable attorney's fees incurred in connection with defending against such damages) shall not be excluded by this Section 7.3 as to recovery hereunder. Subject to the preceding sentence, the Company, on behalf of each of the Company Indemnified Parties, and Operator, on behalf of each of the Operator Indemnified Parties, waive any right any such Person may have to recove punitive, special, exemplary or consequential damages, including damages for lost profits arising in or regarding this Agreement or the transactions contemplated hereby, EVEN IF SUCH INDIRECT DAMAGES ARE BASED UPON THE NEGLIGENCE (WHETHER GROSS, JOINT, CONCURRENT OR PASSIVE), STRICT LIABILITY, OR OTHER FAULT OF THE PARTY WHOSE LIABILITY IS BEING WAIVED HEREBY.

7.4 Defense of Liabilities. The Company and Operator agree to defend each other respectively against all suits brought upon any Liability covered by such Person's foregoing indemnity obligations but each Party reserves the right, at its option, to participate at its own expense, with counsel of its own selection, in the defense of any such Liability without releasing the other Party from any indemnity obligation hereunder. An Indemnified Party may employ separate counsel to represent such Indemnified Party if such Indemnified Party is advised by counsel that an actual conflict of interest makes it advisable for such Indemnified Party to be represented by separate counsel and the reasonable expenses and fees of such separate counsel shall be paid by the Indemnifying Party.

7.5 No Warranties or Guarantees. EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, NEITHER PARTY MAKES WARRANTIES OR GUARANTEES TO THE OTHER, EITHER EXPRESS OR IMPLIED, WITH RESPECT TO THE SUBJECT MATTE AGREEMENT, AND BOTH PARTIES DISCLAIM AND WAIVE ANY IMPLIED WARRANTIES OR WARRANTIES IMPOSED INCLUDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

Article 8
Term and Termination

8.1 Term. Subject to earlier termination under Section 8.2, the initial term of this Agreement shall begin on the Effective Date and continue in effect until April 3, 2023 (such period, the "Initial Term"), and shall be automatically extended thereafter for successive one year periods (each, a "Renewal Term") unless either Party provides written notice, indicating that it does not wish to renew, at least 180 days prior to the end of the Initial Term or a Renewal Term, as applicable. The Initial Term and all Renewal Terms shall be collectively referred to herein as the "Term".

8.2 Termination. This Agreement may be terminated prior to the end of the Term as follows:

(a) at the election of either Party, upon (i) the sale of all of the issued and outstanding Membership Interests to a Third Party, (ii) the sale of all or substantially all of the Company's Assets to a Third Party, (iii) an equity exchange with a Third Party of all of the Membership Interests or of all of the equity interests in any of the Company's subsidiaries, or (iv) a merger or consolidation of any of the Superior Companies with a Third Party;

(b) by the mutual written agreement of the Parties;

(c) by the Company, after receiving notice or otherwise learning fewer than 30% of the Membership Interests (as adjusted for any split or combination of Membership Interests since the Closing Date or any distribution of Membership Interests received by Operator, or an Affiliate of Operator, since the Closing Date) are owned, directly or indirectly, and Controlled by Operator, or an Affiliate of Operator;

(d) by the Company, upon the negligence, gross negligence, willful misconduct or fraud by Operator or the failure by Operator to pay any undisputed amounts when due or to perform any of its obligations under this Agreement and such

Operator failure or action (i) causes actual economic damages (excluding indirect, consequential, punitive or exemplary damages or damages for lost profits except to the extent that Company is obligated to pay such damages to any Third Party), which damages, net of any proceeds of insurance, are over $7,500,000, (ii) is not excused by Force Majeure events, and (iii) is not cured by Operator (to the extent that such a breach is capable of being cured) at no additional cost, liability or expense to the Company within 30 days after Operator's receipt of written notice thereof from the Company (unless such failure is not reasonably capable of being cured within such 30-day period, in which case Operator shall have commenced remedial action to cure such failure within such 30-day period, shall continue to diligently and timely pursue the completion of such remedial action after such notice, and shall have completed such remedial action as soon as is reasonably possible, but in any event within 120 days after commencing such cure);

(e) by the Company, if Operator, Unit or Unit Petroleum Company (i) makes a general assignment for the benefit of creditors; (ii) files a voluntary, or consents to filing an involuntary, bankruptcy petition for relief under the United States Bankruptcy Code; (iii) becomes the subject of an order for relief or is declared insolvent in any federal or state bankruptcy or insolvency proceeding; (iv) files a petition or answer in a court of competent jurisdiction seeking for Operator, Unit or Unit Petroleum Company a reorganization, arrangement, composition, readjustment, liquidation, dissolution, or similar relief under any Law; (v) files an answer or other pleading admitting or failing to contest the material allegations of a petition filed against Operator, Unit or Unit Petroleum Company in a proceeding of the type described in clauses(i) through (iv); (vi) seeks, consents, or acquiesces to the appointment of a trustee, receiver, or liquidator of Operator, Unit or Unit Petroleum Company or of all or any substantial part of any such company's assets or properties; or (vii) is the subject of a final and non-appealable order of relief under the United States Bankruptcy Code by a court with competent jurisdiction under a petition by or against Operator, Unit or Unit Petroleum Company (each of clauses (i) through (vii), an "Operator Bankruptcy Event");

(f) by the Company, if (i) Operator stops or suspends payment of any of its debts, or cannot, or admits its inability to, pay its debts as they become due, (ii) any debt of Operator becomes due, or capable or being declared due prior to its stated maturity by an event of default (howsoever described), or (iii) Operator otherwise materially breaches any debt covenant, and, in each case described clause (i) through (iii), such default or delinquency remains uncured after any cure or grace period and is not waived by Operator's creditor; or

(g) by Operator, if the Company fails to pay any undisputed amount when due under this Agreement if such failure is not remedied within 30 days after written notice of such failure is given.

8.3 Effects of Termination.

(a) The termination or expiration of this Agreement shall not relieve either Party of any Liability or obligation that accrued prior to such termination or deprive a

Party not then in breach (other than a breach because such Party is rightfully withholding performance in response to a breach by the other Party) of its rights to any remedy otherwise available to such Party, and all costs and expenses incurred through the date of termination that are reimbursable under this Agreement shall be paid by the Company. The Company's obligation to reimburse Operator for any costs or expenses incurred under this Agreement shall survive the termination of this Agreement. In addition, Article 1, Article 9 (Dispute Resolution), Article 11 (Audits) and Article 12 (Other Provisions) and Section 5.1, Section 5.2, Section 5.3, Section 7.1, Section 7.2, Section 7.3, Section 7.4 and this Section 8.3 shall survive in full force and effect any expiration or termination of this Agreement for 2 years after such expiration or termination.

(b) Upon termination of this Agreement, Operator shall promptly relinquish its role as operator, ensure the transition of performing the Services to such Person as designated by the Company (such Person, the "Successor Operator"), and, to the extent requested by the Company, provide the Services under the same terms set forth herein (including all payments as provided in Article 5) for a period of time not to exceed 90 days. Operator shall promptly deliver to the Successor Operator, or such other Person as the Company may designate, copies of all files and records related to the Services and its duties and obligations hereunder and all other information about the Company Assets requested by the Company in the possession of Operator. Prior to any such termination, Operator shall identify and provide a list of employees who have historically spent most of their working time in the performance of the Services to Company and Successor Operator. Successor Operator shall be permitted to make offers of employment to such employees and Operator shall provide any cooperation reasonably requested by the Company or Successor Operator in the transition of such employees from Operator to Successor Operator. In addition, for a period of time not to exceed 90 days after the Successor Operator has taken over performance of the Services, Operator shall, to the extent that it is able to do so with the employees it retains, provide any and all such other transition support assistance reasonably requested by the Company, and the Company shall reimburse Operator for any related and reasonable out of pocket costs and expenses.

Article 9
Dispute Resolution

9.1 Dispute Resolution. Before initiating any legal proceeding regarding a Dispute between the Parties, the Party asserting such Dispute must provide the other Party with a notice in writing, setting forth a reasonably complete statement detailing the Dispute and the factual and legal grounds for such Dispute (the "Executive Negotiation Notice"). Within 15 days after a Party receives the Executive Negotiation Notice, the Parties will engage in good faith in-person "executive to executive" negotiations with executives familiar with the matters related to the Dispute. Such executives will have authority to negotiate and settle the dispute subject to such executives first obtaining the consent for any such settlement from the Party which they represent. If the Parties to such Dispute are unsuccessful in resolving such Dispute within 45 days after delivery of the Executive Negotiation Notice, then the Dispute shall be resolved through legal proceedings in accordance with Section 12.11.

Article 10
Operating Records and Reports

10.1 Books and Records. Operator shall maintain and retain records related to performance of the Services. The Company and its Representatives shall have reasonable access to such books and records under Section 11.1.

10.2 Financial Reports. Operator shall provide to the Company the Financial Reports, as they are received, produced or compiled.

10.3 Government Reports. Operator will prepare and timely file or submit any reports required by any Governmental Authority having jurisdiction over the Company Assets, the Superior Companies, and/or the Services, and each such report shall be prepared and filed or submitted in compliance with the instructions, rules and regulations applicable to each such report. Operator shall consider in good faith any comments provided in writing by the Company to Operator with respect to any report that is to be filed with or submitted to a Governmental Authority. Any reports under the name of the Company and requiring a signature shall be executed by a duly authorized representative of the Company.

10.4 Tax Reports. Operator agrees to cooperate with the Company in the preparation of the Company's and the Members' federal, state and local tax returns, including providing, upon written request by the Company, all pertinent information in the possession of Operator that is necessary to enable such tax returns of the Company and the Members to be timely prepared and filed.

Article 11
Audits

11.1 Inspections. The Company, Members holding not less than 20% of the Membership Interests of the Company, or any of their respective Representatives, upon reasonable notice to Operator, but collectively no more than once per calendar quarter, shall have the right to inspect (or cause its Representatives to inspect) the books, records and other documents maintained by Operator under Section 10.1. Such inspection shall occur during Operator's regular business hours following not less than 7 Business Day's prior written notice. The party requesting the inspection shall, and shall cause their Representatives to, perform such inspection in a reasonable period of time and shall use reasonable efforts to minimize inconvenience to Operator's personnel and disruption of the Company's business.

11.2 Audits. Subject to Section 11.3, The Company, upon reasonable notice to Operator, shall have the right to audit (or cause their Representatives to audit) the books, records and other documents maintained by Operator under Section 10.1, including environmental, health and safety audits (collectively, an "Audit").

11.3 Audit Procedures. Following not less than 30 days prior written notice, the Company shall be entitled to conduct one Audit every 12 Calendar Months but shall not Audit a period ending prior to the date that is three years prior to such Audit request. Company shall perform (or cause its designated Representatives to perform) such audit in a reasonable period of time and shall use reasonable efforts to minimize inconvenience to Operator's personnel and disruption of the Company's business. Any information obtained by the Company in connection with the conduct of an Audit (whether related solely to the Company, Operator, the Services or otherwise) shall be subject to the confidentiality provisions of this Agreement. At the conclusion of each Audit, the Company and Operator shall endeavor to settle outstanding matters expeditiously. If no settlement can be reached by the Parties regarding any disputed matter in an Audit, Article 9 shall apply to such disputed matter.

Article 12
Other Provisions

12.1 Counterparts. This Agreement may be executed in multiple counterparts and delivered by electronic transmission, including by facsimile or attached to an electronic mail in portable document format, each of which shall be deemed an original, and all of which when taken together shall constitute the same instrument.

12.2 Notices. Except as otherwise provided in this Agreement to the contrary, any notice or communication required or permitted to be given under this Agreement shall be in writing and sent to the address of the Party set forth below. Each such notice or other communication shall be sent by personal delivery, by United States Postal Service registered or certified mail (return receipt requested), or by reputable courier service (such as Federal Express or United Parcel Service) to the address provided.

If to the Company: Superior Pipeline Company, L.L.C.
8200 South Unit Drive
Tulsa, Oklahoma 74132
Attention: Mike Hicks
Telephone: (918) 493-7700
E-mail: mike.hicks@superiorpipeline.com

With a copy to:

OPTrust
1 Adelaide Street East, 11th Floor
Toronto, Ontario M5C 3A7
Attention: Ryan McGovern
Phone: (416) 681-3045
Email: RMcGovern@optrust.com

and

Partners Group (USA) Inc.
1660 17th Street, Suite 201
Denver, Colorado 80202
Attention: Travis Chulick
Phone: (303) 606-3763
Email: travis.chulick@partnersgroup.com

If to Operator: SPC Midstream Operating, L.L.C.
8200 South Unit Drive
Tulsa, Oklahoma 74132
Attention: Drew Harding
Telephone: (918) 477-4537
E-mail: drew.harding@unitcorp.com

With a copy to:

Unit Corporation, Attention Office of the General Counsel
8200 South Unit Drive
Tulsa, Oklahoma 74132
Attention: Drew Harding
Telephone: (918) 477-4537
E-mail: drew.harding@unitcorp.com

Any notice in accordance herewith shall be deemed to have been given when delivered to the addressee in person, or by courier, if, in each case, delivered during normal business hours or on the next Business Day if delivered after business hours, or upon actual receipt by the addressee after such notice has either been delivered to an overnight courier or deposited in the United States Mail, as the case may be. As a courtesy, a copy of any notice may be given by electronic mail but shall not constitute notice for this Agreement. The Parties may change the address, telephone numbers, and email addresses to which such communications are to be addressed by giving written notice to the other Parties in the manner provided in this Section 12.2.

12.3 Expenses. Except as otherwise specifically provided, all fees, costs and expenses incurred by the Parties in negotiating this Agreement or in consummating the transactions contemplated by this Agreement shall be paid by the Party incurring the same, including legal and accounting fees, costs and expenses.

12.4 Waivers; Rights Cumulative. The terms, covenants or conditions may be waived only by a written instrument executed by or on behalf of the Party waiving compliance. No course of dealing by any Party, or its respective Representatives, or any failure by a Party to exercise any of its rights under this Agreement shall operate as a waiver thereof or affect in any way the right of such Party at a later time to enforce the performance of such provision. No waiver by any Party of any condition, or any breach of any term or covenant in this Agreement, in any one or more instances, shall be deemed to be or construed as a further or continuing waiver of any such condition or breach or a waiver of any other condition or of any breach of any other term or covenant. The rights of the Parties under this Agreement shall be cumulative and the exercise or partial exercise of any such right shall not preclude the exercise of any other right.

12.5 Entire Agreement. This Agreement (including the Exhibits and Schedules hereto, and the documents and instruments executed and delivered in connection herewith) constitutes the entire agreement among the Parties regarding the subject matter hereof and supersedes all prior and contemporaneous agreements and understandings, whether written or oral, between the Parties regarding the subject matter hereof, including the Original Agreement, and there are no representations, understandings, or agreements relating to the subject matter hereof that are not fully expressed in this Agreement and the documents and instruments executed and delivered in connection herewith. All Exhibits and Schedules attached to this Agreement are made a part of, and incorporated by reference into, this Agreement.

12.6 Amendment. This Agreement may be amended only by an instrument in writing executed by all of the Parties.

12.7 Binding Effect and Assignment; Parties in Interest This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns. Neither this Agreement nor the rights, benefits or obligations hereunder shall be assigned by any Party, in whole or in part, without the prior written consent of the other Party. No assignment of any rights hereunder by any Party shall relieve such Party of any obligations and responsibilities hereunder. Except as set forth in Article 7, 10 and 11, nothing in this Agreement, express or implied, should confer upon any Person other than the Parties, or their respective permitted successors and assigns, any rights, remedies, obligations or Liabilities under or by reason of this Agreement.

12.8 Confidentiality.

(a) Operator acknowledges that Operator shall receive information from or regarding the Superior Companies like trade secrets or that otherwise is confidential information or proprietary information (as further defined below, "Confidential Information"), the release of which would be damaging to the Superior Companies and/or Persons with whom the Superior Companies conduct business. Operator shall hold in strict confidence any Confidential Information that Operator receives and shall not disclose such Confidential Information to any Person (other than the Superior Companies and the Company's Members, and officers) or otherwise use such information for any purpose other than for the performance of the Services, except for disclosures:

(i) to comply with any Laws (including stock exchange or quotation system requirements) or under any legal proceedings or because of any Order of any Governmental Authority binding upon a Party; provided, that the Operator shall notify the Company promptly and in advance of any Confidential Information so required to be disclosed, and any such disclosure of Confidential Information shall be to the minimum extent required by such Laws, legal proceedings or Order;

(ii) to Affiliates, partners, members, managers, stockholders, directors, officers, employees, agents, contractors, attorneys, professional consultants or lenders of the Operator where such disclosure is necessary for the performance of the Services hereunder; provided, that, regarding professional consultants and contractors of Operator, prior to such disclosure by Operator, such professional consultant or contractor of Operator shall (to the extent practicable) contract with Operator to keep such disclosure confidential;

(iii) of information that the Operator received from a source independent of the Superior Companies and that Operator reasonably believes such source obtained without breach of any obligation of confidentiality to the Superior Companies;

(iv) has been or becomes independently developed by Operator or its Affiliates without using any of the Confidential Information;

(v) is or becomes generally available to the public (other than because of a prohibited disclosure by Operator, its Affiliates, or their respective Representatives); or

(vi) to the extent the Company shall have consented to such disclosure in writing.

(b) Operator agrees that breach of this Section 12.8(b) by Operator, its Affiliates, or their respective Representatives or any other Person would cause irreparable injury to the Superior Companies for which monetary damages (or other remedy at law) would be inadequate because of (i) the complexities and uncertainties in measuring the actual damages that would be sustained by such breach and (ii) the uniqueness of the Superior Companies' business and the confidential nature of the Confidential Information. Accordingly, Operator agrees that this Section 12.8(b) may be enforced by the Company by temporary or permanent injunction (without the need to post bond or other security therefor), specific performance or other equitable remedy and by any other rights or remedies that may be available at law or in equity. The term "Confidential Information" shall include any information pertaining to the Superior Companies' business which is not available to the public, whether written, oral, electronic, visual form or in any other media, including such information that is proprietary, confidential or about the Superior Companies' ownership and operation of the Company Assets, the Company Business, their operations and business plans, actual or projected revenues and expenses, finances, Contracts and books and records.

12.9 Release of Information. The Parties shall cooperate with each other in releasing information about this Agreement and the transactions contemplated hereby. No press releases or other public announcements about this Agreement shall be made by any Party without prior consultation with, and agreement of, the other Party, unless such press release, public statement or other public disclosure is required by Law regarding Company's or Operator's (including Operator's Affiliates') reporting and disclosure obligations, in which case the disclosing Party shall notify the other Party in advance of any such disclosure, work in good faith to consider and include any suggested changes to the information to be disclosed, and only disclose information to the minimum extent required by Law.

12.10 Governing Law. This Agreement has been executed and delivered and shall be construed, interpreted and governed under the Laws of the State of Texas, without regard to any conflict of Laws principles which, if applied, might permit or require the application of the Laws of another jurisdiction.

12.11 Mandatory Venue. Each Party consents and submits to personal jurisdiction in any action brought in the United States federal courts in the State of Texas (or, if jurisdiction is not available in the United States federal courts in the State of Texas, to personal jurisdiction in any action brought in the state courts in the State of Texas) regarding any dispute, claim, or controversy arising out of or in relation to or in connection with this Agreement, and each of the Parties agrees that any action instituted by it against the other regarding any such dispute, controversy, or claim will be instituted exclusively in the United States federal courts in the State of Texas (or, if jurisdiction is not available in the United States federal courts in the State of Texas, ther exclusively in the state courts in the State of Texas).

12.12 Waiver of Jury Trial. THE PARTIES HEREBY WAIVE ANY RIGHT TO TRIAL BY JURY IN ANY ACTION ARISING OUT (RELATING TO THIS AGREEMENT, WHETHER NOW EXISTING OR HEREAFTER ARISING, AND WHETHER SOUNDING IN CC TORT OR OTHERWISE. THE PARTIES AGREE THAT EITHER OF THEM MAY FILE A COPY OF THIS PARAGRAPH WITH ANY CC WRITTEN EVIDENCE OF THE KNOWING, VOLUNTARY AND BARGAINED-FOR AGREEMENT BETWEEN THE PARTIES IRRE' TO WAIVE TRIAL BY JURY AND THAT ANY ACTION WHATSOEVER BETWEEN THEM RELATING TO THIS AGREEMENT SHALL I BE TRIED IN A COURT OF COMPETENT JURISDICTION BY A JUDGE SITTING WITHOUT A JURY.

12.13 Severability. If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of Law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect if the economic or legal substance of the transactions contemplated hereby is not affected in any adverse manner to any Party. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the Parties shall negotiate in good faith to modify this Agreement to effect the original intent of the Parties as closely as possible in an acceptable manner to the end that the transactions contemplated hereby are fulfilled to the extent possible.

12.14 Intellectual Property. All intellectual property rights (including rights in patents, trade secrets, copyrights, and trademarks) in all inventions, designs, models, drawings, prints, samples, transparencies, specifications, reports, manuscripts, working notes, documentation, manuals, photographs, negatives, tapes, discs, software, computer files or any other items related to the Company Assets, including any such intellectual property rights conceived, created, developed or improved by, or assisted by, Operator or any contractor or which are wholly or in part based on or derived from information arising from performing Services, are and shall remain owned by the Company, including all goodwill related thereto (collectively, "IP") and Operator and its successors and permitted assigns shall have a non-exclusive, royalty-free license to use such IP. To the extent ownership in any IP is not automatically vested in the Company upon such conception, creation, development or improvement, Operator hereby assigns, and shall ensure that its contractors assign, all right, title and interest in such IP to the Company. Operator shall, and shall ensure that its contractors shall, execute such documents, including agreements with its employees and subcontractors, as are necessary to effectuate the Company's ownership of all right, title, and interest in the IP.

12.15 Force Majeure.

(a) For this Agreement, the term "Force Majeure" shall mean an event beyond the control of the Party claiming Force Majeure, including any acts of God, wars, blockades, insurrections, riots, epidemics, lightning, earthquakes, fires, floods, high water washouts, storms or inclement weather which necessitate extraordinary measures and expense to maintain operations, or notice of any of the foregoing which may necessitate the precautionary shut down of plants or pipelines (including the Company Assets), explosions, breakage or accident to machinery or lines of pipe, freezing of wells or pipelines, inability to obtain or delays in obtaining additional necessary easements, rights of way or permits, or the failure or interruption of power or gas supplies or other utilities. The Party prevented or hindered from performing hereunder shall give written notice to the other Party when reasonably practicable and take all reasonable actions within its power to remove the basis for the Force Majeure (including securing alternative supply sources) and after doing so resume performance as soon as possible.

(b) Notwithstanding any other provision of this Agreement to the contrary, if a Party is rendered unable, wholly or in part, by Force Majeure to carry out its obligations (including with Operator, the Services) under this Agreement (other than any obligation to pay any amount when due and payable hereunder), the obligation of such Party, so far as it is affected by such Force Majeure, shall be suspended during the continuance of the condition or event of Force Majeure, but for no longer period, and such condition or event shall so far as possible be remedied with all reasonable dispatch.

(c) It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the affected Party, and that the above requirement that any Force Majeure shall, so far as possible, be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of such Persons to do so when such course is inadvisable in the reasonably exercised discretion of the affected Party.

12.16 Further Assurances. Each Party agrees to execute and deliver to the other Party such additional documents, to take such additional actions and to provide such cooperation as may be reasonably required to consummate the transactions contemplated by, and to effect the intent of, this Agreement, including filing any regulatory forms with Governmental Authorities reasonably necessary to effectuate the transactions contemplated by this Agreement.

12.17 Laws and Regulations and Agreements. This Agreement is subject to all present and future valid Orders, rules and regulations of any regulatory body having jurisdiction and to all applicable Laws of, and agreements, with the United States of America and the State of Texas, including, but not limited, to any Orders, rules, regulations, Laws or agreements specifically referred to herein.

[Signature page follows.]

IN WITNESS WHEREOF, the Parties have entered into this Agreement to be effective as of the Effective Date.

COMPANY:

SUPERIOR PIPELINE COMPANY, L.L.C.

By: /s/ David P. Dunham
Name: David P. Dunham
Title: Senior Vice President

OPERATOR:

SPC MIDSTREAM OPERATING, L.L.C.

By: /s/ Drew Harding
Name: Drew Harding
Title: Vice President

EXHIBIT A

SERVICES

Accounting[1]

- Support Superior's financial statement audit as requested by Superior's accountants or auditors.
- Provide monthly and quarterly closing schedule and technical accounting support to Superior's accountants.

- Provide services to support enterprise resource planning and accounting processing transition.
- Provide certain access and authority to use the Enertia operating system, including expense, A/P, A/R, budgeting and other modules necessary to maintain accounting records and financial statements.
- Provide development support for internal controls, internal audits, and accounting policies and procedures.
- Assist Superior with establishment of new accounts for all services currently necessary for stand-alone operations (including but not limited to Information Technology, Employee Benefits, Payroll, Human Resources, and Geographic Information Services).

Treasury

- Conduct credit checks.
- Process checks and wire transfers.
- Provide bank account administration.
- Coordinate with Unit's accounting personnel to assist with contract counterparty transfer to new Superior bank accounts.

Payroll

- Issue payroll checks and direct deposit confirmations.
- Maintain payroll system and database.
- Process garnishments.
- Administer payroll related withholdings, tax filings and payments.
- Produce all W2's.

Human Resources

- Recruiting and applicant tracking assistance.
- Manage personnel records.
- Provide leave processing.
- Provide support for benefits.
- Administer COBRA notices and enrollment.
- Provide compensation administration (e.g., survey data, salary recommendations, pay adjustments)
- Provide incentive and executive compensation analysis.
- Provide wellness plan administration.

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[1] Shared Services do not include any accounting services that Unit Corporation normally engages outside third party consultants to perform on its behalf or at its direction, but does include collaborating with and assisting such outside consultants to facilitate their work. Fees of outside consultants engaged to represent or advise the Company in connection with accounting matters are not included in the Operating Fee and are chargeable to the Company, subject to any restrictions set forth in the LLC Agreement.

- Prepare compensation statements.
- Provide performance appraisal administration.
- Provide medical plan subrogation administration.
- Provide open enrollment administration.
- Provide medical plan dependent audit assistance.
- Provide service award administration.
- Provide access to Employee Self Service Portal.
- Respond to third party requests for employment verification.
- Provide consulting on general human resources and benefits issues.

Information Technology

- Maintain and support relevant existing computer and IT services necessary to continue the business operations of the Superior's assets, including the following services:
  - Computer desktop support;
  - Maintenance and support of office telephones as well as local and long-distance telephone equipment and service invoices;
  - Field communications maintenance and support and related invoices and fees including any tower, radio, cellular or other network/communications related items; and
  - Other miscellaneous business system and software support, including application and software support and email service support.
- Maintain and assist in the acquisition and implementation of end user computing equipment and software, office equipment (copiers, scanners, fax machines, etc.).
- Manage a service desk which provides a single point of contact for any request for IT services or issues with services in accordance with Unit's practices.
- Support e-mail (Microsoft Outlook), enterprise email infrastructure (Microsoft Exchange), and anti-virus and spam filtering services.
- Create, maintain, and provide access to shared resources for the enterprise in accordance with Unit's practices. Specifically, these shared resources will include secure access to space on servers, printers, electronic mail, intranet and internet portals, internet connections, networks, database management, storage area networks, failover systems and disaster recovery, firewall, and network administrators, among others.
- Detect, troubleshoot, and repair the intranet, LAN, WAN, and internet when degraded performance or total failure occurs, including providing fo appropriate notification of outages and their expected duration.
- Provide access to SharePoint portals related to Superior's operations.
- Assist Superior to: 1) establish relationship with and 2) effectuate transfer to Superior's new IT service provider(s).
- Continuity of the following services (to the extent Unit is providing services to Superior today): Gas Scheduling/Control, SCADA, Radios, G Measurement and other similar field operational services including conversions to any new stand-alone hardware, software or communication systems.
- Maintain current telephone (land lines and cellular), cable, internet and IT services with Unit's existing providers.

Tax[2]

- Manage preparation and filing of all applicable state and federal returns.
- Manage filing of federal and state extensions and estimates.
- Review and analyze tax notices and, in coordination with the Company, negotiate assessed values with tax assessors and/or their agents.
- Advise the Company on and arrange for tax strategy and other possible tax savings opportunities and coordinate property tax budgeting items.
- Provide tax compliance support.

Safety, Health, and Environmental[3]

- SH&E Management System
  - Provide administrative assistance, including website management;
  - Provide program information storage and recordkeeping; and
  - Provide SH&E program consultation.
- SH&E Training
  - Provide consultation for training program; and
  - Provide administrative assistance for Learning Management System.
- Safety – Personnel
  - Provide consultation for safety policies, programs, procedures, and standards; and
  - Assist with facility inspections, including hazard identification and corrective measures.
- Safety – Pipeline
  - Provide consultation for regulatory inspections;
  - Provide consultation for the Risk and Integrity Management Plan.
- Safety – Process (PSM Facilities)
  - Provide consultation for the applicability, process, and compliance with PSM regulations.
- Health
  - Provide assistance with hearing conservation and chemical surveys and monitoring.
- Environmental – General
  - Provide consultation for compliance issues;
  - Provide assistance with maintaining environmental permits; and
  - Maintain records regarding air and storm water permits, spill prevention control and countermeasure plans, and greenhouse gas reporting.
- Environmental – Air
  - Provide consultation for permitting and compliance; and
  - Provide assistance with management of air permitting activities, including Air Pollution Emission Notices, self-certification forms, annual and semi-annual compliance certifications, semi-annual deviation reports and NESHAP notifications.
- Environmental – Water/Soil
  - Provide consultation for SPCC Plans; and
  - Provide assistance with spill response management.
- Environmental – Waste

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[2] Shared Services do not include any tax services that Unit Corporation normally engages outside third party consultants to perform on its behalf or at its direction, but does include collaborating with and assisting such outside consultants to facilitate their work. Fees of outside consultants engaged to represent or advise the Company in connection with tax matters are not included in the Operating Fee and are chargeable to the Company, subject to any restrictions set forth in the LLC Agreement.

[3] Shared Services do not include any HSE services that Unit Corporation normally engages outside third party consultants to perform on its behalf or at its direction, but does include collaborating with and assisting such outside consultants to facilitate their work. Fees of outside consultants engaged to represent or advise the Company in connection with HSE matters are not included in the Operating Fee and are chargeable to the Company, subject to any restrictions set forth in the LLC Agreement.

- o Provide consultation for hazardous waste issues.

Geographic Information

- Provide assistance with capturing, storing, analyzing, managing, and presenting geographic information related to Superior's Facilities, including requested hard copy plots, prints, PDFs and maps.

Legal[4,5]

- Manage procurement of legal services to represent Superior's interests when developing, negotiating, and establishing Third Party Contracts.
- Ensure that all such Third Party Contracts comply, in all material respects, with applicable Laws.
- Manage procurement of legal services to represent Superior's interests during any threatened or pending litigation to which Company is a party.
- Provide, or cause to be provided, legal services relating to and supporting the services which are customarily supplied by in-house legal support and required to implement and conduct the Company business and which are similar to the legal services that are provided for by other companies of similar size that are engaged in the business of gathering, processing and transportation of products with a similar size in-house legal support.

Risk Management

- Provide, or manage and coordinate risk management services to represent Superior's interests when developing, negotiating and establishing Third Party Contracts.

Regulatory Affairs[6]

- Manage and coordinate regulatory services to secure approvals from any agency having jurisdiction over certain customer services that the Company provides using the Company Assets to implement and conduct the Company Business.
- Regulatory services include the preparation, filing, and processing of (a) applications for waivers, declaratory orders, and other authorizations that the Company deems necessary or advisable in implementing and conducting its business, (b) routine and periodic reports, and (c) other regulatory matters as directed by the Company.
- Complete periodic government surveys and other requirements.

Financing

- Coordinate the preparation of financial guarantees as required by the Company.

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[4] Shared Services expressly exclude any Legal Services related to disputes between the Company and any Unit Corporation Affiliate.
[5] Shared Services do not include any legal services that Unit Corporation normally engages outside counsel to perform on its behalf or at its direction, but does include collaborating with and assisting such outside counsel to facilitate the representation. Fees of outside legal counsel engaged to represent the Company's interest are not included in the Operating Fee and are chargeable to the Company, subject to any restrictions set forth in the LLC Agreement.
[6] Shared Services do not include any regulatory affairs services that Unit Corporation normally engages outside third party consultants to perform on its behalf or at its direction, but does include collaborating with and assisting such outside consultants to facilitate their work. Fees of outside consultants engaged to represent or advise the Company in connection with regulatory affairs matters are not included in the Operating Fee and are chargeable to the Company, subject to any restrictions set forth in the LLC Agreement.

- Manage all treasury/cash management related activities except as specifically provided otherwise in this Agreement.

Public Relations

- Assist with public disclosures of Company activities.

AMENDMENT NO. 2 TO
SECOND AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT

This Amendment No. 2 (this "Amendment") to that certain Second Amended and Restated Limited Liability Company Agreement of Superior Pipelin Company, L.L.C., a Delaware limited liability company (the "Company"), dated as of July 1, 2019 (as amended, the "LLC Agreement"), is adopted, executed and agreed to effective as of March 1, 2022 (the "Amendment Date"), by SP Investor Holdings, LLC, a Delaware limited liability company ("SP Holdings"), and Unit Corporation, a Delaware corporation ("Unit").

WHEREAS, SP Holdings and Unit hold all of the issued and outstanding membership interest of the Company;

WHEREAS, the LLC Agreement was previously amended effective as of March 1, 2020; and

WHEREAS, the parties desire to further amend the LLC Agreement as set forth in this Amendment.

NOW, THEREFORE, in consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. Definitions. Capitalized terms used and not defined in this Amendment have the respective meanings assigned to such terms in the LLC Agreement.

2. Amendments to the LLC Agreement. The LLC Agreement is hereby amended as follows:

2.1 Section 1.1 of the LLC Agreement is hereby amended as follows:

2.1.1 The following definitions are hereby inserted in Section 1.1 of the LLC Agreement in applicable alphabetical order:

"Capital Project" means, regarding any Company Asset, any physical enhancement or series of physical enhancements, including any such physical enhancements that would increase the throughput or transportation capacity (including by expanding or adding pump or compressor stations or storage capability, or using drag reducing agents) or extend the useful life or operational efficiency of or to any existing portion of such Company Asset.

"Company Operations" means the development, acquisition, operation, maintenance, repair, expansion, construction and decommissioning of the Company Assets as conducted by the Company from time to time.

"Emergency Services" means services that are necessary, in the Company's reasonable judgment, to be rendered in order to (a) mitigate, remedy or prevent (i) the endangerment of the health or safety of any Person, property or the environment, including injury, illness, death of any Person and damage to the Company Assets; or (ii) a violation of Law; or (b) protect the safety or operational condition of any Company Asset.

"Excess Capital Expenditure Allowance" means $2,500,000 for each year.

"Operations Shortfall Notice" means notice of an Operations Shortfall.

"Required Expenditures" means Capital Expenditures or Operating Expense necessary or required (a) to maintain the Company Assets unde manufacturer recommendations and/or prudent industry practice, (b) to ensure safety in accordance with prudent industry practice; (c) to cause the capital assets or operations of the Company to comply with Laws, or (d) to permit the Company to comply with the terms of its Materia Contracts pertaining to the Company Assets.

"Superior Companies" means the Company and its Subsidiaries, including Superior Appalachian Pipeline, L.L.C., Superior Pipeline Texas, L.L.C., Preston County Gas Gathering, L.L.C. and Superior Pipeline Kansas, L.L.C.

"Third Party Costs" means costs and expenses actually and reasonably incurred and attributable to that are payable to a Third Party.

2.1.2 The definition of "Approved Cost" is hereby amended and restated to read in its entirety as follows:

"Approved Costs" means (i) the Operating Expenses contemplated by the then current Budget plus an additional 10% of such Operating Expenses, (ii) the Capital Expenditures shown in the then current Budget plus the Excess Capital Expenditure Allowance for such Capital Expenditures, (iii) Emergency Expenditures, and (iv) any deductibles and self-retention amounts payable in connection with any loss or claim covered by insurance.

2.1.3 The definition of "Available Cash" is hereby amended by deleting the word "Operator" therein and replacing it with the word "Company".

2.1.4 The definition of "Emergency Expenditures" is hereby amended and restated to read in its entirety as follows:

"Emergency Expenditures" means expenditures that are necessary, in the Company's reasonable judgment, to be expended to render Emergency Services, including, to avoid doubt, any Third Party Costs actually incurred to render such Emergency Services.

2.1.5 The definition of "Material Contract" is hereby amended by deleting the word "Operator's" therein and replacing it with the word "Company's".

2.1.6 The definition of "MSA" is hereby amended and restated to read in its entirety as follows:

"MSA" means the Amended and Restated Management Services and Operating Agreement, dated as of March 1, 2022, by and between the Company and Operator, as same may be amended or restated.

2.1.7 The definition of "Officer" is hereby amended and restated to read in its entirety as follows:

"Officer" means any person appointed as an officer of the Company as provided in Section 6.9, excluding (other than for purposes of the definition of "Indemnitee") any person who has ceased to be an officer of the Company.

2.1.8 The definition of "Operations Shortfall" is hereby amended and restated to read in its entirety as follows:

"Operations Shortfall" means, after exhausting the amounts available under any lines of credit or other loans to which any Superior Company is a party (considering the cash reserves that have been approved by the Board), the amount by which (i) the estimated Approved Costs to be incurred by the Company in such calendar month exceed (ii) the Company's cash assets in the Company Bank Accounts and projected gross revenue available to satisfy such estimated costs and expenses for such calendar month (considering the cash reserves that have been approved by the Board) at any time during a calendar month.

2.1.9 The definition of "Operator" is hereby amended and restated to read in its entirety as follows:

"Operator" means SPC Midstream Operating, L.L.C. and its Affiliates, or their respective successor or permitted assigns, in each case as the operator under the MSA.

2.1.10 The definition of "Third Party Contract" is hereby amended and restated to read in its entirety as follows:

"Third Party Contract" means any Contract entered into by the Company or a Subsidiary of the Company with a Third Party, pursuant to which services, supplies, materials, or equipment related to the Company Assets will be provided to the Company by a contract, supplier, or other vendor.

2.2 Section 2.8(c) of the LLC Agreement is hereby amended by deleting the last sentence thereof.

2.3 Section 4.2(a) of the LLC Agreement is hereby amended and restated to read in its entirety as follows:

The Company will immediately provide each of the Members with notice of an Emergency Expenditure or Emergency Service and details of the same (each, an "Emergency Notice") and promptly, but in no event later than 48 hours after receipt by the Company of such notice, convene a meeting of the Members. The Company shall include in the Emergency Notice the aggregate required Emergency Expenditures ("Emergency Expenditure Amount") and, if applicable, a calculation of required additional cash funds in excess of the Emergency Reserves (any such excess being the "Emergency Shortfall Amount") and the date by which funds to pay such Emergency Expenditures would need to be funded into or otherwise available in the Company Bank Accounts (such date, the "Emergency Funding Deadline"), which Emergency Funding Deadline will not be less than 20 days after the date the Emergency Notice is delivered to the Members.

2.4 Section 4.3(a) of the LLC Agreement is hereby amended by deleting the second sentence thereof and replacing it with the following: "If there is an Operations Shortfall, the Company will deliver an Operations Shortfall Notice to the Applicable Members (a "Shortfall Notice") within five Business Days after the Operations Shortfall is determined."

2.5 Section 6.2(b) of the LLC Agreement is hereby amended by inserting the word "and" immediately following the semicolon in clause (i) thereof and by deleting clause (ii) thereof.

2.6 Section 6.4(h) of the LLC Agreement is hereby amended by deleting the phrase "and manage and control the business and affairs of the Company" therein.

2.7 Section 6.4(i) of the LLC Agreement is hereby amended and restated to read in its entirety as follows:

Except for any matters that are delegated by the Board to the Managing Member or the Officers of the Company in accordance herewith, all other matters will be subject to the vote or consent by the Board, including the matters set forth in Section 6.6.

2.8 Section 6.6(b)(ii) of the LLC Agreement is hereby amended by deleting the phrase "(other than an amendment of an Affiliate Contract that Operator is permitted to enter into under Section 5.4(a) of the MSA)" therein.

2.9 Section 6.6(b)(xxvi) of the LLC Agreement is hereby amended and restated to read in its entirety as follows:

"hire, terminate, appoint or remove any Officers of the Company or any of its Subsidiaries;"

2.10 Section 6.6(c) of the LLC Agreement is hereby amended by deleting the phrase "(other than any amendment of an Affiliate Contracts that Operator is permitted to enter into under Section 5.4(a) of the MSA)" therein.

2.11 Section 6.8(b) of the LLC Agreement is hereby amended and restated to read in its entirety as follows:

Annual Budgets. For each Fiscal Year starting January 1, 2019, the Capital Expenditures and Operating Expenses (including general and administrative expenditures) to be made by the Company for that Fiscal Year and the sources of funding (cash flow from operations, financing activities or capital contributions) for the Capital Expenditures and Operating Expenses is to be set forth in a budget (a "Draft Budget") to be considered and adopted by the Board (as adopted, a "Budget"). Each Budget will be prepared and approved or disapproved by the Board in this manner:

(i) The Officers will prepare and submit for approval of the Board a Draft Budget regarding the operation and maintenance of the Company Assets during the next succeeding Fiscal Year after consulting with the Board regarding the proposed plans of the Company for that Fiscal Year. The Draft Budget will itemize the costs estimated in the Budget by individual line items and by categories as are reasonably requested by any Board Manager and will set forth the sources of funding (cash flow from operations, financing activities, or capital contributions) for the Capital Expenditures and Operating Expenses to be made in the DraftBudget. The Officers will submit to the Board a Draft Budget by December 1 of any Fiscal Year for the next succeeding Fiscal Year. Each such Draft Budget shall contain at least the following:

(A) estimates of Operating Expenses during such calendar year;

(B) estimates of all expenditures, during such calendar year, necessary for the Company to (y) comply with Laws, and (z) fulfill its obligations under any Material Contracts to which any of the Superior Companies is a party;

(C) estimates of Capital Expenditures during such calendar year (and for each subsequent calendar year) for any ongoing Capital Projects and any Capital Projects proposed to be commenced during such calendar year;

(D) estimates of other Capital Expenditures covered by the Draft Budget, by budget category, containing enough detail to afford the reasonable identification of the nature, scope, and duration of the activity in question;

(E) estimates of the schedule, by calendar month, under which the Operating Expenses and Capital Expenditures in the Budget are anticipated to be incurred by the Company over such calendar year;

(F) estimates of cash flow from operations and financing activities for such calendar year to be used to pay estimated expenditures for such calendar year, and if such cash flow, with any reserves, is insufficient to pay all such expenditures, the estimated amount of capital contributions to be funded by the Members during such calendar year and the estimated dates such capital will be needed; and

(G) any other information and/or supporting details or documentation requested in writing by the Company that can reasonably be provided by the Officers.

(ii) The Board will approve or disapprove a Draft Budget within thirtydays after distribution by the Officers. If the Board has failed to approve a Draft Budget by the start of a Fiscal Year, then, until the Board has approved a Budget for that Fiscal Year, (A) the Company may incur costs consistent with the Default Budget and (B) the DefaultBudget will be deemed the Budget, and the Company may incur Approved Costsand any other amounts in the Default Budget. Despite the absence of an approved Budget, besides the foregoing, the Officers may approve the Company's incurrence of Capital Expenditures or Operating Expenses to the extent necessaryor appropriate to address any Emergency Expenditures. If a Budget has not been approved by the start of a

Fiscal Year, the Board will endeavor to work with the Officers on modifications to the Draft Budget so the Board can approve same as promptly as practicable.

(iii) If, during the period covered by an approved Budget, the Officers or any Board Manager determines that an adjustment to the estimated costs, expenses, or Capital Expenditures of any line item(s) set forth in the Budget is necessary or appropriate, then the Officers will submit (or cause to be submitted) to the Board for approval an adjusted Draft Budget prepared by the Officers in a manner consistent with this Section 6.8(b), setting forth the adjusted or additional line items as are necessary or required. The Board will approve or disapprove the adjusted Draft Budget as promptly as practicable, but in any event within fifteen days after receipt of the adjusted Draft Budget.

(iv) The Members recognize that itemized expenditures in a Budget may extend over more than one calendar year because such itemized expenditures represent activities or operations that require commitments over one calendar year. Once estimates of multi-year expenditures are approved in a Budget, including such expenditures in a Budget for any later calendar year, until the calendar year in which such expenditures were originally estimated to be completed, shall not require approval of the Company on an annual or other periodic basis, but instead, all such items shall (to the extent not spent in prior periods) be automatically included in such future Budgets as items already approved unless the activity or operation to which such expenditures relate has been completed or abandoned.

(v) If a Budget is not approved on or before the first day of the calendar year to which the Budget pertains, the Company shall be deemed to have approved an interim Budget for that calendar year that includes the following, without duplication of the expenditures described in each category below (such deemed approved Budget, the "Default Budget"): (A) Operating Expenses equal to the Operating Expenses actually expended in the Company Operations in the previous calendar year adjusted upward by an amount equal to 3%; (B) those multi-year expenditures approved by the Company under Section 6.8(b)(iv) attributable to the calendar year; (C) Required Expenditures for the calendar year as reasonably projected by the Officers; (D) existing commitments to any Person under Material Contracts in effect in such calendar year and previously approved by the Company or permitted to be entered into without approval of the Company; (E) taxes payable by the Company; and (F) any other reasonable costs and expenses not in dispute.

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(vi) The Board is deemed to have approved, and the Company may expend, besides any approved Budget, an amount (A) up to an additional 10% of the total Operating Expenses in such approved Budget and (B) up to the Excess Capital Expenditure Allowance for Capital Expenditures for all Capital Projects undertaken, or on-going, in such year and shown in such approved Budget. The deemed approval levels shall be applied using the original amounts in the Budget or, if the Budget is amended, the total amended amount of the Budget; provided that expenditures under the deemed approval amounts shall not be considered an amendment to the Budget that resets such thresholds; and provided, further, that no Emergency Expenditures incurred under Section 6.8(b)(vii) shall be deemed included in an approved Budget for purposes of applying the deemed approval levels under this Section 6.8(b)(vi).

(vii) Notwithstanding anything to the contrary in this Agreement, the Company may make Emergency Expenditures (not to exceed the amount of Emergency Reserves being maintained by the Company in accordance with the terms of this Agreement), perform Emergency Services, and incur liabilities without prior authorization or approval of the Board when an Officer reasonably determines (i) the same is necessary, requisite or proper, (A) to prevent or address health, safety, environmental and legal emergencies or contingencies, including explosions, fires, spills, or any other similar event which poses an immediate and material threat to property, lives, or the environment, or (B) to keep the Company and the Company Assets in compliance with Laws, and (ii) it is impractical to get the Company's prior approval for such expenditures and/or the incurrence of such liabilities. Regarding each emergency, the Company shall, as soon as practicable, but in no event later than 48 hours after the earliest date that an Emergency Expenditure is made or an Emergency Service is performed, report to the Members the nature of any such emergency which arises, the measures the Company has taken and intends to take regarding such emergency, and, if known, the estimated Emergency Expenditures for the related Emergency Services.

(viii) To avoid doubt, any reference in this Agreement to an approved Budget shall include a Default Budget deemed to have been approved by the Company, and shall incorporate all approved amendments thereto and all modifications to such Budget described herein that require no action by the Company.

2.12 Section 6.9 of the LLC Agreement is hereby amended by deleting the proviso in the second sentence thereof and by replacing all references in Section 6.9 to "Managing Member" with "Board", and by inserting the following sentence at the end of Section 6.9.

The president of the Company shall have the authority to hire or terminate the employment of any employees of the Company or any of its Subsidiaries, except with respect to Officers of the Company or officers of any of its Subsidiaries.

2.13 Section 6.10 of the LLC Agreement is hereby deleted in its entirety.

2.14 Section 8.1 of the LLC Agreement is hereby amended and restated to read in its entirety as follows:

The Managing Member will cause the Company to prepare and file all necessary federal, state, and local tax returns, including making the elections described in Section 8.2. No Company tax return shall be filed unless it is consistent with the tax elections described in Section 8.2 and Section 8.3 (unless determined otherwise by the requisite approval of the Board or Applicable Members, as applicable). The Managing Member will, to the extent practicable, provide each Applicable Member with a draft of each Company tax return with sufficient time to review the same and, prior to filing that return, will consider in good faith any objections any Member may have thereto. On written request on behalf of the Company, each Member will furnish to the Company all information in its possession relating to Company operations that is necessary to enable the Company's tax returns to be prepared and filed.

2.15 Section 9.1 of the LLC Agreement is hereby amended by replacing the reference to "Company" in the first sentence with "Managin Member."

2.16 Section 9.2(a)(vii) of the LLC Agreement is hereby amended by deleting the word "Operator's" therein and replacing it with the wor "Company's" and by deleting the phrase "or Affiliates of the Operator in the Business Area" therein.

2.17 Section 9.2(a)(viii)(D) of the LLC Agreement is hereby amended by deleting the word "Operator" therein and replacing it with the wor "Company".

2.18 Section 9.2(a)(viii)(E) of the LLC Agreement is hereby amended and restated to read in its entirety as follows: "copies of any materia correspondence between the Company and any Governmental Authority related to the Company Assets;".

2.19 Section 9.2(a)(viii)(H) of the LLC Agreement is hereby amended by deleting the word "Operator" therein and replacing it with the wor "Company".

2.20 Section 9.2(b) of the LLC Agreement is hereby amended and restated to read in its entirety as follows: "Intentionally Omitted."

2.21 Section 9.4 of the LLC Agreement is hereby amended by replacing the reference to "PricewaterhouseCoopers" with "Grant Thornton."

2.22 Section 9.5(b) of the LLC Agreement is hereby amended and restated to read in its entirety as follows:

The Company will promptly and, in any event, within five (5) Business Days, notify the Board in writing or by email of any EHS notice ofviolations or noncompliance issued by Governmental Authorities, any investigation the Company has been informed is being conducted by Governmental Authorities regarding EHS matters, anypending administrative or judicial EHS proceedings of which the Company has been notified, anyThird Party lawsuit or written claims involving EHS matters, and any known material release ofhazardous substances as defined under Laws.

2.23 Section 13.12 of the LLC Agreement is hereby amended by deleting "Bob Parks" and replacing it with "Mike Hicks" and deleting bob.parks@unitcorp.com and replacing it with mike.hicks@superiorpipeline.com.

3. Limited Effect. Except as expressly provided in this Amendment, all of the terms and provisions of the LLC Agreement are and will remain in full force and effect and are hereby ratified and confirmed by the Company. On and after the Amendment Date, each reference in the

LLC Agreement to "this Agreement," "the Agreement," "hereunder," "hereof," "herein," or words of like import, and each reference to the LLC Agreement in any other agreements, documents, or instruments executed and delivered pursuant to, or in connection with, the LLC Agreement, will mean and be a reference to the LLC Agreement as amended by all amendments thereto, including this Amendment.

4. Miscellaneous.

(a) *Counterparts*. This Amendment may be executed in any number of counterparts (including facsimile and .pdf counterparts), each of which, when so executed and delivered, shall be deemed an original, and all of which together shall constitute a single instrument. Delivery of a copy of this Amendment bearing an original signature by facsimile transmission or by electronic mail exchange of signature pages shall have the same effect as physical delivery of the paper document bearing the original signature.

(b) *Governing Law*. THIS AGREEMENT IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH LAW OF THE STATE OF DELAWARE, WITHOUT REGARD TO THE CONFLICTS OF LAW PRINCIPLES OF SUCH STATE.

(c) *Partial Invalidity*. If any provision of this Amendment is held to be illegal, invalid or unenforceable under present or future Laws effective during the term of the LLC Agreement, such provision shall be fully severable; this Amendment shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part of this Amendment; and the remaining provisions of this Amendment shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance from this Amendment. Furthermore, in lieu of each such illegal, invalid or unenforceable provision, there shall be added automatically as a part of this Amendment a provision as similar in terms to such illegal, invalid or unenforceable provision as may be possible and be legal, valid and enforceable.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the undersigned have executed this Amendment as of the Amendment Date.

SP INVESTOR HOLDINGS, LLC
a Delaware limited liability company

By: /s/ Ryan McGovern
Name: Ryan McGovern
Title: Authorized Signatory

By: /s/ Todd Bright
Name: Todd Bright
Title: Authorized Signatory

UNIT CORPORATION
a Delaware Corporation

By: /s/ Drew Harding
Name: Drew Harding
Title: Vice President and General Counsel

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

All the companies listed below are included in the company's consolidated financial statements. Except as otherwise indicated below, the Company has 100% direct or indirect ownership of, and ultimate voting control in, each of these companies. The list is as of December 31, 2021 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%
Superior Pipeline Company, L.L.C.	Oklahoma	50%

Exhibit 23.1

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the filing of our reserves audit report dated February 21, 2022, as Exhibit 23.1 to the Unit Corporation annual report on Form 10-K for the year ended December 31, 2021 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 31, 2022

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 31, 2022

/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 31, 2022

/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, 2021 (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, 2021 and December 31, 2020 and for the year ended December 31, 2021, the four months ended December 31, 2020, and the eight months ended August 31, 2020.

Dated: March 31, 2022

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

Dated: March 31, 2022
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, 2021

\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
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

February 21, 2021

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, 2021 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 February 14, 2021 and presented herein, was prepared for public disclosure by Unit in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.The estimated reserves shown herein represent Unit's estimated net reserves attributable to the leasehold interests in certain properties owned by Unit and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2021.The properties reviewed by Ryder Scott incorporate 402 reserves determinations and are located in the states of Louisiana, Montana, 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 reserves as of December 31, 2021.Based on the estimates of total net proved reserves prepared by Unit, the reserves audit conducted by Ryder Scott addresses 83 percent of the total proved developed net liquid hydrocarbon reserves and 77 percent of the total proved developed net gas reserves of Unit.

The properties reviewed by Ryder Scott account for a portion of Unit's total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2021. Unit informed Ryder Scott that the selected entities included approximately 85 percent of Unit's discounted future net income at 10% for the total proved developed reserves, which is also 85 percent of the total proved reserves.

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, 2021 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, 2021, 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. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Unit attributable to Unit's interest in properties that we reviewed and for those that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests of
Unit Corporation
As of December 31, 2021

	Total Proved Developed Producing
Net Reserves of Properties Audited by Ryder Scott	
Oil/Condensate – MBarrels	7,685
Plant Products – MBarrels	17,726
Gas - MMcf	169,502
Net Reserves of Properties Not Audited by Ryder Scott	
Oil/Condensate – MBarrels	1,334
Plant Products – MBarrels	3,799
Gas - MMcf	51,138
Total Net Reserves	
Oil/Condensate – MBarrels	9,019
Plant Products – MBarrels	21,525
Gas - MMcf	220,640

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. However, in certain cases, the gas volumes presented herein include gas consumed in operations as reserves. In those cases, Unit reduced the effective price such that the fuel volumes had no value.

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 A 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 chiefly 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 classifications, 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 tha 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 or the volumetric method. Approximately 99 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed 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 November 2021, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Unit or obtained from public data sources and were considered sufficient for the purpose thereof.The remaining 1 percent of the proved producing reserves that we reviewed were estimated by the volumetric method. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

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

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

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

The initial SEC hydrocarbon prices in effect on December 31, 2021 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 which 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 using information provided by Unit; 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 of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$66.56/Bbl	$64.68/Bbl
	NGLs	Mont Belvieu Non TET Propane	$44.22/Bbl	$29.24/Bbl
	Gas	Henry Hub	$3.60/MMBTU	$3.47/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. In certain cases, the gas volumes presented herein include gas consumed in operations as reserves. In those cases, Unit reduced the effective price such that the fuel use had no value.

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

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

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

Unit's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, 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, geological structural and isochore maps, well logs, core analyses, 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, 2021 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 17 percent of the total proved net liquid hydrocarbon reserves and 23 percent of the total proved net gas reserves based on estimates prepared by Unit as of December 31, 2021.

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 have received 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 analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

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

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

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

Very truly yours,

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

/s/ Robert J. Paradiso

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

[SEAL]

RJP (LPC)/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 Scot Company, L.P. Robert J. Paradiso was the primary technical person responsible for overseeing the estimate of the reserves, future production anc 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 Coordinato 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 anc Gas, Inc., Norcen Explorer, Inc., Amerac Energy Corporation, Halliburton Energy Services, Santa Fe Snyder Corp., and Devon Energy CorporationFor more information regarding Mr. Paradiso's geographic and job specific experience, please refer to the Ryder Scott Company website a 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 Professiona 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 o 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 2021 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 RegisterMr. Paradiso attended an additional 23¾ hours of formalized in-house training during 2021 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management Syste 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 42 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 o 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 chiefly 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 classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or afte 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 o 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.*

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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).

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

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

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

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