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, 2020

OR

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

For the transition period from to
Commission file number: 1-9260

Unit Corporation

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

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

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

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting 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

Portions of the information called for by Part III will be included in an amendment to this Form 10-K or incorporated by reference from the registrant's definitive Proxy Statement to be filed pursuant to Regulation 14A.

Exhibit Index—See Page 135

FORM 10-K
UNIT CORPORATION

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

ARO – Asset retirement obligations.

ASC – FASB Accounting Standards Codification.

ASU – Accounting Standards Update.

Bcf – Billion cubic feet of natural gas.

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.

BOKF – Bank of Oklahoma Financial Corporation.

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 equivalents.

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)(3) of Regulation S-X.

Proved reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences 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 – before the time when 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)(2)(i) through (iii) 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)(4) 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 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.

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.

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 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, 2020.

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;
- 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;
- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- the amount and terms of our debt;
- future compliance with covenants under our credit agreements;
- our ability to remediate a material weakness in our internal controls over financial reporting;
- 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, 2020

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 internet 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 an internet website at *www.sec.gov* that contains reports, proxy and information statements, and other information about us we file electronically with the SEC.

Also, we post on our internet website, *www.unitcorp.com*, copies of our corporate governance documents. Our corporate governance guidelines and code of ethics are available for free on our website 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.
- *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 us as of March 10, 2021:

Oil and Natural Gas	
Total number of wells in which we own an interest	5,651
Contract Drilling	
Total number of drilling rigs available for use	57
Mid-Stream	
Number of natural gas treatment plants we own	3
Number of processing plants we own	11
Number of natural gas gathering systems we own	17

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. For more information regarding the Chapter 11 Cases and other related matters, please read Note 2 – Emergence From Voluntary Reorganization Under Chapter 11.

2020 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

- Segment G&A decreased by 39% from 2019, after excluding one-time Predecessor separation benefit plan costs and Predecessor legal settlements.
- LOE decreased by 33% from 2019.
- Capital expenditures decreased by 96% from 2019.
- Production decreased by 29% from 2019 and we participated in one net non-operated well.

Contract Drilling

- Utilization cycle during 2020:
  - Began the year with 20 drilling rigs operating;
  - Drilling rig activity began a dramatic decrease in the second and third quarters as a result of the OPEC and Russia oil price war and the beginning of the COVID-19 pandemic. Rig activity dropped to a low of four drilling rigs operating and two drilling rigs on standby at the end of July;
  - Rig activity slowly increased through the remainder of the third quarter and the fourth quarter, ending the year with nine drilling rigs operating – six BOSS rigs and three SCR rigs.
- The 2020 average drilling rig dayrate of $18,641 was essentially unchanged from 2019.

Mid-Stream

- Connected 22 new wells to our gathering and processing systems from various producers.
- Successfully integrated the 2019 mid-continent acquisition into the Reeding processing facility on the Cashion system.
- Reduced operating expenses by approximately 17% from 2019.
- Reduced G&A by approximately 23% from 2019.
- Connected four new wells to an existing pad on our Pittsburgh Mills system which increased gathered volume by approximately 57 MMcf per day.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 20 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, 2020:

	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2020 Average Net Daily Production		
					Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
Total	5,650	1,996.78	2	0.17	102,643	5,974	9,412

Acquisitions. There were no significant acquisitions in 2019 or 2020.

Dispositions. We had non-core asset sales, net of related expenses, of $0.4 million, $1.2 million and $21.8 million during the Successor Period and Predecessor Period of 2020, and 2019, respectively. Proceeds from these sales reduced the net book value of the full cost pool with no gain or loss recognized.

Successor Period Impairment. As of September 1, 2020, we adopted fresh start accounting and adjusted our assets to fair value. Although under fresh start accounting we recorded our assets at fair value on emergence, the application of the full cost accounting rules resulted in non-cash ceiling test write-downs of $26.1 million during the Successor Period of 2020, primarily due to the use of average 12-month historical commodity prices for the ceiling test versus forward prices for our Fresh Start fair value estimates.

We do not anticipate a non-cash ceiling test write-down in the first quarter of 2021 of our proved reserves. It is hard to predict with any certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at December 31, 2020, and only adjust the 12-month average price to be as of March 2021, our forward-looking expectation is that we will not recognize an impairment in the first quarter of 2021. Given the uncertainty associated with the factors used in calculating our estimate of our future period ceiling test write-down, these estimates should not necessarily be construed as indicative of our future plans or financial results and the actual amount of any write-down may vary significantly from this estimate depending on the final future determination.

Predecessor Period Impairments. During the Predecessor Period of 2020, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $393.7 million pre-tax ($346.6 million net of tax) due to the reduction in the 12-month average commodity prices and the impairment of our unproved oil and gas properties described below. In 2019, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $559.4 million pre-tax ($422.4 million net of tax) due to the reduction of the 12-month average commodity prices and the removal of proved undeveloped reserves due to the uncertainty regarding our ability to finance future capital expenditures.

Our decision to withhold costs from amortization and the timing of transferring those costs into the amortization base involve significant judgment determinations which may change over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. During the first quarter of 2020, we determined that, because of the increased uncertainty in our business, our undeveloped acreage would not be fully developed and thus certain unproved oil and gas properties carrying values were not recoverable. This resulted in an impairment of $226.5 million, which had a corresponding increase to our depletion base and contributed to our full cost ceiling impairment recorded during the first quarter of 2020. In 2019, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. Those determinations resulted in $73.9 million of costs being added to the total of our capitalized costs being amortized. At December 31, 2020, we had approximately $1.6 million of costs excluded from the amortization of our full cost pool.

In addition to the impairment evaluations of our proved and unproved oil and gas properties in the first quarter of 2020, we also evaluated the carrying value of our salt water disposal assets. Based on our revised forecast of use of those assets, we determined some of those assets were no longer expected to be used and wrote off certain salt water disposal assets that we considered abandoned. We recorded expense of $17.6 million related to abandonment of our salt water disposal assets in the first quarter of 2020.

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

	Successor		Predecessor			
	Period September 1, 2020 through December 31, 2020		Period January 1, 2020 through August 31, 2020		For the Year Ended December 31, 2019	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Development:						
Oil	2	0.31	10	0.07	16	9.98
Natural Gas	1	—	12	0.28	99	19.17
Dry	—	—	—	—	—	—
Total development	3	0.31	22	0.35	115	29.15
Exploratory:						
Oil	—	—	—	—	—	—
Natural gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory	—	—	—	—	—	—
Total wells drilled	3	0.31	22	0.35	115	29.15

	Year Ended December 31,			
	2020		2019	
	Gross	Net	Gross	Net
Wells producing or capable of producing:				
Oil	1,534	604.79	1,534	604.79
Natural gas	4,601	1,598.32	4,601	1,598.32
Total	6,135	2,203.11	6,135	2,203.11

Cost for development drilling includes $77.2 million in 2019, to develop previously booked proved undeveloped oil and natural gas reserves. We developed no previously booked proved undeveloped oil and natural gas reserves in 2020.

This table summarizes our leasehold acreage at December 31, 2020:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net [(1)]	Gross	Net
Total	528,297	336,961	50,326	26,921	578,623	363,882

1. Approximately 87% of the net undeveloped acres are covered by leases that will expire in the years 2021—2023 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	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
Average sales price per barrel of oil produced:			
Price before derivatives	$ 39.23	$ 35.14	$ 55.13
Effect of derivatives	(1.94)	(3.16)	2.36
Price including derivatives	$ 37.29	$ 31.98	$ 57.49
Average sales price per barrel of NGLs produced:			
Price before derivatives	$ 9.28	$ 4.83	$ 12.42
Effect of derivatives	—	—	—
Price including derivatives	$ 9.28	$ 4.83	$ 12.42
Average sales price per Mcf of natural gas produced:			
Price before derivatives	$ 1.91	$ 1.11	$ 1.88
Effect of derivatives	0.01	0.03	0.16
Price including derivatives	$ 1.92	$ 1.14	$ 2.04

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
Oil production (MBbls):			
Jazz Wilcox field	61	184	417
Buffalo Wallow field	48	118	243
Mendota field	35	76	118
All other fields	482	1,184	2,430
Total oil production	626	1,562	3,208
NGLs production (MBbls):			
Jazz Wilcox field	206	601	1,278
Buffalo Wallow field	261	618	1,237
Mendota field	155	327	479
All other fields	423	853	1,779
Total NGLs production	1,045	2,399	4,773
Natural gas production (MMcf):			
Jazz Wilcox field	2,414	7,003	14,361
Buffalo Wallow field	2,651	6,214	11,843
Mendota field	967	2,059	3,108
All other fields	4,974	11,287	23,753
Total natural gas production	11,006	26,563	53,065
Total production (MBoe):			
Jazz Wilcox field	669	1,952	4,089
Buffalo Wallow field	751	1,772	3,454
Mendota field	352	746	1,115
All other fields	1,734	3,918	8,167
Total production	3,506	8,388	16,825
Average production cost per equivalent Bbl [(1)]	$ 5.27	$ 4.86	$ 5.71

1. Excludes ad valorem taxes and gross production taxes.

Our Buffalo Wallow field in Hemphill County, Texas, contained 16% and 10% of our total proved reserves in 2020 and 2019, respectively, expressed on an oil-equivalent barrels basis. Our Mendota field, in the Granite Wash play in the Texas Panhandle, contained 16% and 8% of our total proved reserves for those same years also expressed on an oil-equivalent barrels basis. Our Jazz Wilcox field in South Texas, which includes our Gilly, Segno, and Wildwood prospects and several smaller prospects, contained 8% and 21% 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. This table identifies our estimated proved developed and undeveloped oil, NGLs, and natural gas reserves:

	Successor			
	Year Ended December 31, 2020			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Total proved developed	8,267	15,208	144,391	47,541
Total proved undeveloped	—	—	—	—
Total proved	8,267	15,208	144,391	47,541

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. We use Ryder Scott to audit the reserves prepared by our reservoir engineers. Ryder Scott has been providing petroleum consulting services throughout the world 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, 2020, and comprised approximately 85% of the total proved developed future net income discounted at 10% (based on the SEC's unescalated pricing policy).

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 by Ryder Scott, the reservoir department reviews all properties for accuracy of forecasting.

Technical Qualifications

Ryder Scott – 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. As part of his 2020 continuing education hours, Mr. Paradiso attended 6.5 hours of formalized training during the 2020 RSC Reserves Conference relating to the definitions and disclosure guidelines in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Paradiso attended an additional 83 hours of formalized in-house training during 2020 covering such topics as Greenhouse Gas Reporting, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

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.

The Company – 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.

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, 2020, 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, 2020 and 2019, the changes in quantities, and standardized measure of those reserves for the three 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. During the Successor Period of 2020, one customer accounted for 14% of our oil and natural gas revenues. During the Predecessor Period of 2020, two customers accounted for 26% of our oil and natural gas revenues. Besides our mid-stream segment, no other company accounted for over 10% of our oil and natural gas revenues. During the Successor Period and Predecessor Period of 2020, our mid-stream segment purchased $10.6 million and $11.8 million, respectively, of our natural gas and NGLs production and provided gathering and transportation services of $1.2 million and $2.8 million, respectively. 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. In 2019, we eliminated intercompany revenues of $47.5 million, attributable to the intercompany purchase of our production of natural gas and NGLs and gathering and transportation services.

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, New Mexico, Wyoming, and North Dakota.

This table identifies certain information about our contract drilling segment:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
Number of drilling rigs available for use	58.0	58.0	58.0
Average number of drilling rigs owned	58.0	58.0	56.9
Average number of drilling rigs utilized	7.2	11.5	24.6
Utilization rate [(1)]	12 %	20 %	43 %
Average revenue per day [(2)]	$ 21,974	$ 26,106	$ 18,736
Total footage drilled (feet in 1,000's)	1,062	2,999	7,615
Number of wells drilled	67	179	423

1. Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the year.
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. During the Successor Period and Predecessor Period of 2020, nine and 20 of our 58 drilling rigs, respectively, were used in drilling services.

This table shows certain information about our drilling rigs as of March 10, 2021:

	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Drilling Rigs	10	47	57	20,263

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. As commodity prices declined mid-year, so did drilling rig utilization. The volatility of commodity prices coupled with the supply and demand economics of oil, natural gas, and NGLs has caused a continued decline in US land drilling rig utilization.

At any given time, the number of drilling rigs we can work depends on several conditions besides demand, including the availability of qualified labor and 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:

	2020	2019
First quarter	18.7	31.4
Second quarter	9.1	28.6
Third quarter	5.1	20.4
Fourth quarter	7.6	18.3

Drilling Rig Fleet. The size of our drilling rig fleet did not change during 2020; it remained at 58 drilling rigs.

Dispositions, Acquisitions, and Construction. During 2019, we completed construction and placed into service our 12th, 13th, and 14th BOSS drilling rigs. These drilling rigs are subject to long-term contracts with third party operators.

Predecessor Period Impairments. At March 31, 2020, due to market conditions, we performed impairment testing on two asset groups comprising our SCR diesel-electric drilling rigs and our BOSS drilling rigs. We concluded that the net book value of our SCR drilling rigs asset group was not recoverable through estimated undiscounted cash flows and we recorded a non-cash impairment charge of $407.1 million in the first quarter of 2020. We also recorded an additional non-cash impairment charge of $3.0 million for other miscellaneous drilling equipment.

We concluded that no impairment was needed on our BOSS drilling rigs asset group as the relevant estimated undiscounted cash flows exceeded the carrying value of the asset group. The carrying value of the asset group was approximately $242.5 million at March 31, 2020. The estimated undiscounted cash flows of the BOSS drilling rig asset group exceeded the carrying value by a relatively minor margin, which means very minor changes in certain key assumptions in future periods may result in material impairment charges in future periods. Some of the more sensitive assumptions used in evaluating the contract drilling rigs asset groups for potential impairment include forecasted utilization, gross margins, salvage values, discount rates, and terminal values.

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 in 2020 and 2019 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 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 range from six months to three years and the rates can either be fixed throughout the term or allow for periodic adjustments.

Customers. During the Successor Period of 2020, five customers accounted for 95% of our contract drilling revenues. During the Predecessor Period of 2020, three customers accounted for 51% of our contract drilling revenue. No other third-party customer accounted for 10% or more of our contract drilling revenues.

Our contract drilling segment also provides drilling services for our oil and natural gas segment. During 2019, our contract drilling segment drilled 50 wells for our oil and natural gas segment, or 12% of the total wells drilled by our contract drilling segment. The contract drilling segment did not drill any wells for our oil and natural gas segment in 2020. 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. The contracts for these services are issued under similar terms and rates as the contracts signed with unrelated third parties. By providing drilling services for the oil and natural gas segment, we eliminated revenue of $15.8 million during 2019 from our contract drilling segment and eliminated the associated operating expense of $14.2 million yielding $1.6 million as a reduction to the carrying value of our oil and natural gas properties. We eliminated no revenue in our contract drilling segment during 2020.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries, of which we presently own 50% interest. Its operations consist of buying, selling, gathering, processing, and treating natural gas. It operates three natural gas treatment plants, 11 processing plants, 17 active gathering systems, and approximately 2,090 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 the 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 $260,560.

The Agreement specifies how future distributions are to be allocated among the Members. Future distributions may be from available cash or made in conjunction with a sale event (both as defined in the Agreement). In certain circumstances, future distributions could result in Unit receiving distributions that are disproportionately lower than its ownership percentage. Circumstances that could result in Unit receiving less than a proportionate share of future distributions include, but may not be limited to, Unit not fulfilling the drilling commitment described in Note 18 – Commitments and Contingencies or a cumulative return to SP Investor Holdings, LLC of less than the 7% Liquidation IRR Hurdle provided for SP Investor Holdings, LLC in the Agreement. Generally, the 7% Liquidation IRR Hurdle calculation requires cumulative distributions to SP Investor Holdings, LLC in excess of its original $300.0 million investment sufficient to provide SP Investor Holdings, LLC a 7% IRR on its capital contributions to Superior before any liquidation distribution is made to Unit. After the fifth anniversary of the effective date of the sale, either owner may force a sale of Superior to a third-party or a liquidation of Superior's assets.

This table presents certain information regarding our mid-stream segment for the years indicated:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
Gas gathered—Mcf/day	324,892	388,506	435,646
Gas processed—Mcf/day	135,615	158,031	164,482
NGLs sold—gallons/day	441,761	612,301	625,873

Dispositions and Acquisitions. Superior did not have any significant dispositions or acquisitions during 2020.

In December 2019, we closed on an acquisition for $16.1 million that included approximately 572 miles of pipeline and related compressor stations. The transaction closed on December 30, 2019 with an effective date of December 1, 2019.

Predecessor Period Impairments. During the first quarter of 2020, we determined that the carrying values of certain long-lived asset groups in southern Kansas, and central Oklahoma (where lower pricing is expected to impact drilling and production levels), were not recoverable and exceeded their estimated fair value. Based on that determination, we recorded non-cash impairment charges of $64.0 million.

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, 2020, 83% of our mid-stream segment's total volumes and 81% 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, 2020, 17% of our mid-stream segment's total volumes and 19% 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. During the Successor Period of 2020, two customers accounted for 43% of our mid-stream revenues. During the Predecessor Period of 2020, three customers accounted for 52% of our mid-stream revenue. We believe that if we lost these customers, there are other customers available to purchase our natural gas and NGLs. During the Successor Period of 2020, Predecessor Period of 2020, and the year 2019, Superior purchased $10.6 million, $11.8 million, and $40.6 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $1.2 million, $2.8 million, and $6.9 million, respectively. 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 10, 2021, we had 645 employees, none of whom are members of a union or labor organization. Our workforce includes 333 employees in our contract drilling segment, 146 employees in our oil and natural gas segment, 114 employees in our mid-stream segment, and 52 in our general corporate area. 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 PRICE

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;
- governmental policies and subsidies;
- the costs of exploring for, producing, and delivering oil and 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. For example, the oil prices fell about 20% on March 9, 2020, due to Saudi Arabia's decision to increase its production to record levels.

And prices of oil, NGLs, and natural gas can be influenced by trading on the commodities markets. That trading has increased the volatility associated with these prices, causing large differences in prices even weekly and monthly.

Based on our Successor Period of 2020 production, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $254,000 per month ($3.1 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 $147,000 per month ($1.8 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 $260,000 per month ($3.1 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 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 oil, NGLs, and natural gas 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. During 2020, we had derivative contracts on about 42% and 39% of our 2020 average daily production for oil and natural gas, respectively, and no derivative contracts for NGLs. 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, including associated goodwill and other intangible assets, 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, NATURAL GAS, AND NGL 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.

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. On December 31, 2020, we had $0.6 million and $98.4 million outstanding current portion of long-term debt and long-term debt, respectively, under the Exit Credit Agreement and no 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.

On December 31, 2020, we had $0.6 million and $98.4 million of current portion and long-term debt, respectively, under our Exit Credit Agreement and nothing 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 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. For example, 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. As of the time of this filing, cases of COVID-19 in the U.S. are still increasing. The effects of COVID-19 and concerns about its global spread have weakened the domestic and international demand for crude oil and natural gas, which has hurt crude oil prices and caused 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. 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, 2020, we had no proved undeveloped drilling locations. Those locations were removed due to the uncertainty over our ability to finance future capital expenditures.

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 Successor Period of 2020, one customer accounted for 14% of our oil and natural gas revenue. During the Predecessor Period of 2020, two customer accounted for 26% of our oil and natural gas revenues. During the Successor Period of 2020, five customers accounted for 95% of our contract drilling revenues. During the Predecessor Period of 2020, three customers accounted for 52% of our contract drilling revenue. During the Successor Period of 2020, two customers accounted for 43% of our mid-stream revenues. During the Predecessor Period of 2020, three customers accounted for 51% of our mid-stream revenue. 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.

We have identified a material weakness in our internal control over financial reporting (ICFR). If we do not develop or maintain an effective internal controls system, we may not accurately report our financial results or prevent fraud. As a result, current and potential stockholders could lose confidence in our financial reporting, which could harm our business and our stock's trading price.

During the preparation of our interim financial statements for the quarterly period ended June 30, 2020, we determined that a material weakness related to management's review and controls over complex accounting matters was present. A material weakness is a deficiency, or combination of deficiencies, in ICFR such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected timely. The existence of a material weakness could cause errors in our financial statements, cause us to not meet our reporting obligations, and cause investors to lose confidence in our reported financial information, leading to a decline in our stock's trading price.

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.

RISKS TO OUR GROWTH PLANS

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

Our growth plans will 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 grown each segment, in part, 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. 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 depends 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.

Constructing our new proprietary BOSS drilling rigs is subject to risks, including delays and cost overruns, and may not meet our expectations.

We have designed and built several new 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.

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 FY 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, and the Mississippian of Kansas. 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 and Kansas could have adverse effect on our business and results of operations.

We conduct oil and natural gas exploration, development, and drilling activities in Oklahoma, Kansas, and elsewhere. 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 balance sheets and results of operations are not comparable in many respects to 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 and continue as a going concern.

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 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 shareholders from receiving a premium on their investment.

Our charter and bylaws contain provisions that may delay or discourage change in control transactions or changes in our management or transactions that our 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 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, (iii) consummating a public offering of common stock, (iv) any redemption or repurchase of the company's equity securities or declaring any dividend on the common stock, or (v) incurring an aggregate amount of indebtedness for borrowed money of the company and its subsidiaries over $25 million, except for borrowings under the Exit Credit Agreement.

- The board is divided into two classes, Group I and Group II. The Group I directors will initially serve until the company's 2021 annual meeting of stockholders, and the Group II directors will initially serve until the company's 2022 annual meeting of stockholders. Commencing at the 2021 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.
- So long as the company does not have a class of securities registered under Section 12 of the Exchange Act, holders of 5% of the outstanding common stock who also held at least 5% of the common stock as of the Effective Date will have certain preemptive rights regarding any issuance or sale of the common stock, preferred stock, or certain other securities by the company.
- 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 may be filled by the 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

Voluntary Petitions under Chapter 11 of the Bankruptcy Code

On May 22, 2020, the Debtors filed petitions seeking relief under Chapter 11 of the Bankruptcy Code. The commencement of the Chapter 11 Cases automatically stayed all of the proceedings and actions against the Debtors (other than certain regulatory enforcement matters). On the Effective Date, the automatic stay was terminated and replaced with the injunction provisions in the Confirmation Order and the Plan. For further information, please see Note 2 – Emergence From Voluntary Reorganization Under Chapter 11.

Pending Settlement

In August 2020, Unit Petroleum Company reached an agreement to settle two putative class actions: Cockerell Oil Properties, Ltd. v. Unit Petroleum Company and Chieftain Royalty Company v. Unit Petroleum Company. Under the settlement, Unit Petroleum Company 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. This settlement is subject to certain conditions, including approval 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. Under the Company's (including joint debtor Unit Petroleum Company) approved plan or reorganization, these settlements will be treated as allowed class claims of general unsecured creditors. The settlement amounts will be satisfied by distribution of the plaintiffs' proportionate share of New Common Stock of the of the reorganized company. For further information about the two putative class actions, please see Note 18 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

Before we filed the Chapter 11 Cases, our Old Common Stock traded on the New York Stock Exchange under the symbol "UNT." The high and low closing sales prices per share of our Old Common Stock can be easily accessed for free on numerous websites.

On December 19, 2019, we were notified by the NYSE that we were not in compliance with the NYSE's continued listing requirements, as the average closing price of our Old Common Stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Rule 802.01C of the NYSE Listed Company Manual. Under the NYSE's rules, we had six months following receipt of the notification to regain compliance with the minimum share price requirement.

On May 26, 2020, trading in our Old Common Stock on the NYSE was suspended because of the Debtors' filing of the Chapter 11 Cases. Effective May 27, 2020, trades in our Old Common Stock began being quoted on the OTC Pink Marketplace. On June 10, 2020, the NYSE filed a Form 25 to delist our Old Common Stock and deregister it under Section 12(b) of the Securities Exchange Act of 1934, as amended. On the Effective Date, the Old Common Stock outstanding immediately before the Effective Date were cancelled.

After the Effective Date, we distributed approximately 11.1 million shares of New Common Stock as provided for under the Plan, and expect to distribute another 900,000 shares of the New Common Stock in accordance with 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 under the symbol "UNTC". See "Risk Factors — Our New Common Stock may have a limited market and lack liquidity."

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 our charter, for as long as we do not have a class of securities registered pursuant to Section 12 of the Exchange Act until certain conditions are satisfied, we cannot declare any dividend on our New Common Stock without the consent of holders of at least 50% of our voting stock. In addition, our bank credit agreements prohibit the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit agreements and our senior subordinated notes agreement's impact on our ability to pay dividends, see "Our Credit Agreements and Predecessor Debt" under Item 7 of this report.

Item 6. Selected Financial Data

Not applicable.

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.

General

We were founded in 1963 as a contract drilling company. Today, 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.

Recent Developments

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 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) (Chapter 11 Cases). 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 the Effective Date, the Debtors emerged from the Chapter 11 Cases. For more information regarding the Chapter 11 Cases and other related matters, please read Note 2 – Emergence From Voluntary Reorganization Under Chapter 11.

Fresh Start Accounting

On the Effective Date, we qualified for and adopted fresh start accounting under the provisions set forth in FASB Topic ASC 852 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 existing voting shares of the Predecessor prior to emergence received less than 50% of the voting shares of the emerging entity. As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the Successor financial statements will not be comparable to the financial statements prepared before the Effective Date.

Changes in Accounting Policies

On the Effective Date, we elected to change the accounting policies related to depreciation of fixed assets of our Contract Drilling segment and the allocation of earnings and losses between Unit and its partners in Superior.

- Regarding our Contract Drilling segment, we elected to depreciate all drilling assets using the straight-line method over the useful lives of the assets ranging from four to ten years.
- We elected to begin allocating earnings and losses between Unit and the partners in Superior using the Hypothetical Liquidation at Book Value (HLBV) method of accounting.

Business Outlook

Strategy

Following our emergence from bankruptcy, we are focused on value accretion through generation of free cash flows, repayment of debt, and selective investment in each of our business segments. Investments are expected to be funded using free cash flows from operations, proceeds from divestitures of non-core assets, and available capacity under the Exit Credit Agreement, all subject to the various terms and conditions of the Exit Credit Agreement as referenced in Note 9 – Long-Term Debt and Other Long-Term Liabilities.

In our oil and natural gas segment, we are optimizing production from our existing reserves and converting non-producing reserves to producing, with no exploratory drilling currently planned. We plan to divest non-core properties and use those proceeds along with free cash flows to acquire producing properties in our core areas.

In our contract drilling segment, we are focused on increasing the use of our BOSS drilling rigs, as well as upgrading certain of our SCR drilling rigs. We also plan to continue seeking opportunities to divest non-core, idle drilling equipment.

In our mid-stream segment, we are focused on generating predictable free cash flows with limited exposure to commodity prices. We also plan to continue seeking business development opportunities in our core areas using the Superior credit agreement (which Unit is not a party to nor guarantees) or other financing sources that are available to it.

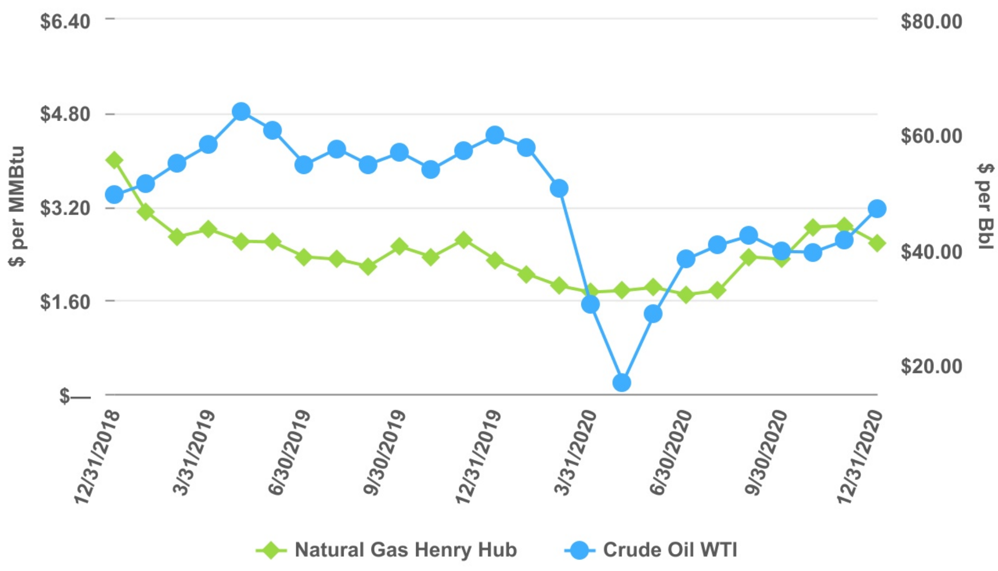
COVID-19 Pandemic and Commodity Price Environment

As discussed in other parts of this report, among other things, our success depends, to a large degree, on the prices we receive for our oil and natural gas production, the demand for oil, natural gas, and NGLs, and the demand for our drilling rigs which influences the amounts we can charge for those drilling rigs. While our operations are all within the United States, events outside the United States affect us and our industry.

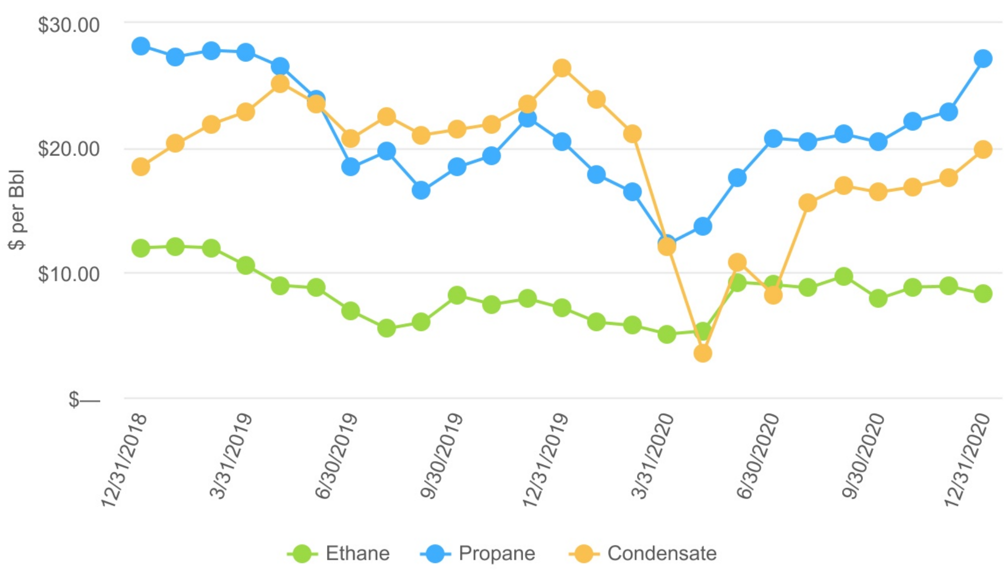
We are continuously monitoring the current and potential impacts of the COVID-19 pandemic on our business. This includes how it has and may continue to impact our operations, financial results, liquidity, customers, employees, and vendors. In response to the pandemic, we have implemented various measures to ensure we are conducting our business in a safe and secure manner. COVID-19 and the response of governments around the world to contain the pandemic have contributed to an economic downturn, reduced demand for oil and natural gas, and together with a price war between Saudi Arabia and Russia, depressed oil and natural gas prices in 2020. The global oil and natural gas supply and demand imbalance continues to be uncertain, with possible on-going and future adverse effects on the oil and gas industry.

During the last two years, commodity prices have been volatile. We reduced our operated rig count in the first quarter of 2019 before getting as high as six drilling rigs in the second quarter of 2019. Due to declining prices, we shut down our own drilling program in July 2019 and used no drilling rigs for the remainder of 2019 and 2020.

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



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



1. NGLs prices reflect a weighted-average, based on production, of Mont Belvieu and Conway prices.

Executive Summary

Oil and Natural Gas

Fourth quarter 2020 production from our oil and natural gas segment was 2,592 MBoe, a decrease of 9% and 38% from the third quarter of 2020 and the fourth quarter of 2019, respectively. The decreases came from fewer net wells being drilled in 2020 to replace the declines in existing drilled wells. Oil and NGLs production during the fourth quarter of 2020 and the fourth quarter of 2019 were each 48% of our total production.

Fourth quarter 2020 oil and natural gas revenues increased 6% over the third quarter of 2020 and decreased 48% from the fourth quarter of 2019. The increase over the third quarter of 2020 was primarily due an increase in commodity prices partially offset by a decrease in equivalent production. The decrease from the fourth quarter of 2019 was primarily due to a decrease in equivalent production and oil and NGLs prices.

Our hedged natural gas prices for the fourth quarter of 2020 increased 56% over third quarter of 2020 and increased 1% over fourth quarter of 2019. Our hedged oil prices for the fourth quarter of 2020 increased 43% over the third quarter of 2020 and decreased 29% from the fourth quarter of 2019, respectively. Our hedged NGLs prices for the fourth quarter of 2020 increased 21% over the third quarter of 2020 and decreased 24% from the fourth quarter of 2019.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 35% over the third quarter of 2020 and decreased 52% from the fourth quarter of 2019. The increase over the third quarter of 2020 was primarily due to an increase in commodity prices and a reduction in saltwater disposal expense and G&A partially offset by a decrease in equivalent production. The decrease from the fourth quarter of 2019 was primarily due to lower revenues due to lower commodity prices and volumes partially offset by lower LOE and G&A.

Operating cost per Boe produced for the fourth quarter of 2020 decreased 10% from the third quarter of 2020 and decreased 3% from the fourth quarter of 2019. The decrease from the third quarter of 2020 was primarily due to lower G&A and saltwater disposal expense. The decrease from the fourth quarter of 2019 was primarily due to lower LOE and G&A partially offset by no longer capitalizing directly related overhead costs in 2020 due to the absence of drilling in 2020.

At December 31, 2020, these non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'21 - Dec'21	Natural gas - basis swap	30,000 MMBtu/day	$(0.215)	NGPL TEXOK
Jan'21 - Oct'21	Natural gas - swap	50,000 MMBtu/day	$2.82	IF - NYMEX (HH)
Nov'21 - Dec'21	Natural gas - swap	45,000 MMBtu/day	$2.90	IF - NYMEX (HH)
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'21 - Dec'21	Crude oil - swap	3,000 Bbl/day	$44.65	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

In western Oklahoma, annual production averaged 73 MMcfe per day (31% oil, 22% NGLs, 47% natural gas) which was a decrease of approximately 24% compared to 2019. During 2020, we did not drill any operated wells in this area and participated in one net non-operated well.

In the Texas panhandle, annual production averaged 67 MMcfe per day (8% oil, 37% NGLs, 55% natural gas) which was a decrease of approximately 27% compared to 2019. During 2020, we did not drill any operated wells in this area, nor did we participate in any non-operated wells.

In our Wilcox play located primarily in Polk, Tyler, Hardin and Goliad Counties, Texas, annual production averaged 45 MMcfe per day (9% oil, 29% NGL's, 62% natural gas) which is a decrease of approximately 41% compared to 2019. During 2020, we did not drill any operated wells in this area, nor did we participate in any non-operated wells.

During the Successor Period and Predecessor Period of 2020, we participated in the drilling of three wells (0.30 net wells) and 16 wells (0.35 net wells), respectively.

Contract Drilling

The average number of drilling rigs we operated in the fourth quarter of 2020 was 7.6 compared to 5.1 and 18.3 in the third quarter of 2020 and fourth quarter of 2019, respectively. As of December 31, 2020, nine of our drilling rigs were operating.

Revenue for the fourth quarter of 2020 increased 24% over the third quarter of 2020 and decreased 59% from the fourth quarter of 2019. The increase over the third quarter of 2020 was due to more drilling rigs operating and increasing dayrates. The decrease from the fourth quarter of 2019 was due to less drilling rigs operating and lower dayrates.

Dayrates for the fourth quarter of 2020 averaged $17,923, which was a 6% increase over the third quarter of 2020 and a 7% decrease from the fourth quarter of 2019. The increase over the third quarter of 2020 was primarily due to more drilling rigs operating. The decrease from the fourth quarter of 2019 was primarily due to less drilling rigs operating.

Operating costs for the fourth quarter of 2020 increased 29% over the third quarter of 2020 and decreased 59% from the fourth quarter of 2019. The increase over the third quarter of 2020 was primarily due to more drilling rigs operating. The decrease from the fourth quarter of 2020 was primarily due to less drilling rigs operating. Operating cost per day for the fourth quarter of 2020 decreased 15% from the third quarter of 2020 and decreased 2% from the fourth quarter of 2019. Revenue days for the fourth quarter of 2020 increased 51% over the third quarter of 2020 and decreased 58% from the fourth quarter of 2019.

Direct profit (contract drilling revenue less contract drilling operating expense) for the fourth quarter of 2020 increased 13% over the third quarter of 2020 and decreased 59% from the fourth quarter of 2019. The increase over the third quarter of 2020 was primarily due to more drilling rigs operating. The decrease from the fourth quarter of 2019 was primarily due to less drilling rigs operating.

The contract drilling segment has operations in Oklahoma, Texas, New Mexico, Wyoming, and North Dakota. As of December 31, 2020, three drilling rigs were working in Oklahoma, three in the Permian Basin of West Texas, two in Wyoming and one drilling rig in the Bakken Shale of North Dakota.

During 2020, almost all our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The future demand for and the availability of drilling rigs to meet that demand will affect our future dayrates.

As of December 31, 2020, we had five term drilling contracts with original terms ranging from two months to one year. Three of these contracts are up for renewal in 2021, (two in the first quarter and one in the second quarter) and two are up for renewal in 2022 and beyond. Term contracts may contain a fixed rate during the contract or provide for rate adjustments within a specific range from the existing rate. Some operators who had signed term contracts have opted to release the drilling rig and pay an early termination penalty for the remaining term of the contract. We recorded $9.2 million and $4.8 million in early termination fees in 2020 and 2019, respectively.

Six of our 14 existing BOSS drilling rigs were under contract as of December 31, 2020.

All our contracts are daywork contracts.

For 2021, capital expenditures for this segment are expected to primarily be for maintenance capital on operating drilling rigs and the possible conversion of certain SCR drilling rigs to AC drilling rigs if practicable. We also plan to pursue the disposal or sale of our non-core, older drilling rig fleet.

Mid-Stream

Fourth quarter 2020 liquids sold per day decreased 31% from the third quarter of 2020 and decreased 24% from the fourth quarter of 2019. The decreases were primarily due to declining volumes and fewer wells connected to our major systems resulting in lower liquids production. For the fourth quarter of 2020, gas processed per day decreased 11% from the third quarter of 2020 and decreased 19% from the fourth quarter of 2019. The decreases were primarily due to declining volumes and fewer wells connected to our major systems. For the fourth quarter of 2020, gas gathered per day decreased 11% from the third quarter of 2020 and decreased 20% from the fourth quarter of 2019. The decreases were primarily due to lower volumes from our major gathering and processing systems resulting from fewer wells connected and declining wellhead volumes.

NGLs prices in the fourth quarter of 2020 increased 35% over the prices received in the third quarter of 2020 and increased 5% over the prices received in the fourth quarter of 2019. Because certain of the contracts used by our mid-stream segment for NGLs transactions are commodity-based contracts – under which we receive a share of the proceeds from the sale of the NGLs – our revenues from those commodity-based contracts fluctuate based on NGLs prices.

Direct profit (mid-stream revenues less mid-stream operating expense) for the fourth quarter of 2020 decreased 45% from the third quarter of 2020 and decreased 12% from the fourth quarter of 2019, respectively. The decrease from the third quarter of 2020 was primarily due to recognizing a shortfall fee in the third quarter of 2020 in the amount of $5.3 million and due to declining volumes on our major systems. The decrease from the fourth quarter of 2019 was primarily due to lower volume on our major systems and lower condensate prices. Total operating cost for this segment for the fourth quarter of 2020 increased 17% over the third quarter of 2020 and decreased 3% from the fourth quarter of 2019. The increase over the third quarter of 2020 was primarily due to an increase in gas purchase cost due to higher purchase prices. The decrease from the fourth quarter of 2019 was primarily due to declining wellhead volumes and fewer wells connected resulting in lower purchased volumes.

At the Cashion processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2020 averaged approximately 64.2 MMcf per day and total production of natural gas liquids averaged approximately 252,000 gallons per day. For 2020, we continued to connect new wells to this system for third party producers. Since the first of 2020, we connected 18 new wells to this system from producers. The total processing capacity of the Cashion system is 105 MMcf per day.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for the fourth quarter of 2020 was 131.7 MMcf per day and average gathered volume for 2020 was 152.3 MMcf per day. During 2020, we connected four new infill wells to an existing well pad.

Also, in the Appalachian area at our Snow Shoe gathering system, the average gathering volume for the fourth quarter was 2.5 MMcf per day and the average gathered volume for 2020 was 3.0 MMcf per day. In 2020, we did not connect any new wells to this system. At Snow Shoe for 2020, we also charged a demand fee based on a volume of 55 MMcf per day. This demand fee volume will be reduced in 2021 to 51 MMcf per day. Additionally, in 2020, we recognized a shortfall fee from a producer on this system for $5.3 million. This fee will be invoiced in the first quarter of 2021.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the fourth quarter of 2020 was 46.6 MMcf per day and average total throughput volume for 2020 was 51.3 MMcf per day. Total average production of natural gas liquids for the fourth quarter of 2020 decreased to approximately 110,000 gallons per day due to operating in ethane rejection. Total production of natural gas liquids for 2020 averaged approximately 152,000 gallons per day. The total processing capacity of the Hemphill system is 135 MMcf per day. In 2020, we did not connect any new wells to this system. Currently there are no active rigs in the area, and we do not anticipate any new well connects for this system.

At the Segno gathering system located in East Texas, the average throughput volume for the fourth quarter of 2020 decreased to approximately 31.0 MMcf per day due to declining production volume along with no new drilling activity in the area. For 2020, the average throughput volume for this system was approximately 40 MMcf per day. During 2020, we did not connect any new wells to this system.

Anticipated 2021 capital expenditures for this segment will be approximately $15.0 million, a 61% increase over 2020.

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. In this discussion we explain the nature of these estimates, assumptions and judgments, and the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

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, 2020 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. Companies, like ours, using full cost accounting 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.

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 to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower DD&A expense in future periods. Once incurred, a write-down cannot be reversed.

The risk 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, 2020, our reserves were calculated based on applying 12-month 2020 average unescalated prices of $39.57 per barrel of oil, $18.70 per barrel of NGLs, and $1.98 per Mcf of natural gas (then adjusted for price differentials) over the estimated life of each of our oil and natural gas properties.

Successor Period Impairment

As of September 1, 2020, we adopted fresh start accounting and adjusted our assets to fair value. Although under fresh start accounting we recorded our assets at fair value on emergence, the application of the full cost accounting rules resulted in non-cash ceiling test write-downs of $26.1 million pre-tax during the Successor Period of 2020, primarily due to the use of average 12-month historical commodity prices for the ceiling test versus forward prices for our Fresh Start fair value estimates.

Under full cost accounting rules we must review the carrying value of our oil and natural gas properties at the end of each quarter. Under those rules, the maximum amount allowed as the carrying value is called the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (using the most recent unescalated historical 12-month average price of our oil, NGLs, and natural gas), plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties in the costs being amortized, less related income taxes. If the net book value of the oil, NGLs, and natural gas properties being amortized exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs, even if prices are depressed for only a short while. Once incurred, a write-down of oil and natural gas properties is not reversible.

We do not anticipate a non-cash ceiling test write-down in the first quarter of 2021 of our proved reserves. It is hard to predict with any certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at December 31, 2020, and only adjust the 12-month average price as of March 2021, our forward-looking expectation is that we will not recognize an impairment in the first quarter of 2021. Given the uncertainty associated with the factors used in calculating our estimate of our future period ceiling test write-down, these estimates should not necessarily be construed as indicative of our future plans or financial results and the actual amount of any write-down may vary significantly from this estimate depending on the final future determination.

Predecessor Period Impairments

Oil and Natural Gas. During the Predecessor Period of 2020, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $393.7 million pre-tax ($346.6 million net of tax) due to the reduction in the 12-month average commodity prices and the impairment of our unproved oil and gas properties described below. In 2019, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $559.4 million pre-tax ($422.4 million net of tax) due to the reduction of the 12-month average commodity prices and the removal of proved undeveloped reserves due to the uncertainty regarding our ability to finance future capital expenditures.

In addition to the impairment evaluations of our proved and unproved oil and gas properties in the first quarter of 2020, we also evaluated the carrying value of our salt water disposal assets. Based on our revised forecast of asset utilization, we determined certain assets were no longer expected to be used and wrote off certain salt water disposal assets that we no longer considered abandoned. We recorded expense of $17.6 million related to the write-down of our salt water disposal assets in the first quarter of 2020.

Mid-stream. We determined that the carrying value of certain long-lived asset groups in our mid-stream segment, where lower pricing is expected to impact drilling and production levels, are not recoverable and exceeded their estimated fair value.

Based on the estimated fair value of the asset groups, we recorded non-cash impairment charges of $64.0 million. These charges are included within impairment charges in our Consolidated Statement of Operations.

Contract Drilling. On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, the expenditures necessary to bring them into working condition and the expected demand for drilling services by rig type. The components comprising inactive rigs are evaluated, and those components with continuing utility to our other marketed rigs are transferred to rigs or to our yards to be used as spare equipment. The remaining components of these rigs are retired.

At March 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 the first quarter of 2020. We also recorded an additional non-cash impairment charges of $3.0 million for other miscellaneous drilling equipment.

We used the income approach to determine the fair value of the SCR drilling rigs asset group. This approach uses significant assumptions including management's best estimates of the expected future cash flows and the estimated useful life of the asset group. Fair value determination requires a considerable amount of judgement and is sensitive to changes in underlying assumptions and economic factors. As a result, there is no assurance the fair value estimates made for the impairment analysis will be accurate in the future.

We concluded that no impairment was needed on the BOSS drilling rigs asset group as the undiscounted cash flows exceeded the carrying value of the asset group. The carrying value of the asset group was approximately $242.5 million at March 31, 2020. The estimated undiscounted cash flows of the BOSS drilling rigs asset group exceeded the carrying value by a relatively minor margin, which means minor changes in certain key assumptions in future periods may result in material impairment charges in future periods. Some of the more sensitive assumptions used in evaluating the contract drilling rigs asset groups for potential impairment include forecasted utilization, gross margins, salvage values, discount rates, and terminal values.

We recorded expense of $1.1 million related to the write-down of certain equipment in the third quarter of 2020 that we consider abandoned.

Costs Withheld from Amortization. Costs associated with unproved properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and related seismic data, the drilling of wells, and capitalized interest are initially excluded from our amortization base. Leasehold costs are transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred.

Our decision to withhold costs from amortization and the timing of transferring those costs into the amortization base involve significant judgment determinations which may change over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. During the first quarter of 2020, we determined that, because of the increased uncertainty in our business, our undeveloped acreage would not be fully developed and thus certain unproved oil and gas properties carrying values were not recoverable. This resulted in an impairment of $226.5 million, which had a corresponding increase to our depletion base and contributed to our full cost ceiling impairment recorded during the first quarter of 2020. In 2019, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. Those determinations resulted in $73.9 million of costs being added to the total of our capitalized costs being amortized. At December 31, 2020, we had approximately $1.6 million of costs excluded from the amortization of our full cost pool.

Accounting for ARO for Oil, NGLs, and Natural Gas Properties. We record the fair value of liabilities associated with the future plugging and abandonment of wells. In our case, when the reserves in each of our oil or gas wells deplete or the wells otherwise become uneconomical, we must incur costs to plug and abandon the wells. These costs are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We have no assets restricted to settle these ARO liabilities. Our engineering staff uses historical experience to determine the estimated plugging costs considering the type of well (either oil, natural gas, or both), the depth of the well, the physical location of the well, and the ultimate productive life to determine the estimated plugging costs. A risk-adjusted discount rate and an inflation factor are used on these estimated costs to determine the current present value of this obligation. To the extent any change in these assumptions affect future revisions and impacts the present value of the existing ARO, a corresponding adjustment is made to the full cost pool.

Drilling Contracts. The type of contract used determines our compensation. All our contracts in 2020 and 2019 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 compensation is based on a negotiated rate to be paid for each day the drilling rig is used.

Accounting for Value of Stock Compensation Awards. To account for stock-based compensation, compensation cost is measured at the grant date based on the fair value of an award and is recognized over the service period, which is usually the vesting period. We elected to use the modified prospective method, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Determining the fair value of an award requires significant estimates and subjective judgments regarding the appropriate option pricing model, the expected life of the award and performance vesting criteria assumptions. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee. All our previously reported awards were terminated because of our Chapter 11 Cases and no awards were outstanding as of December 31, 2020.

Accounting for Derivative Instruments and Hedging. All derivatives are recognized on the balance sheet and measured at fair value. Any changes in our derivatives' fair value before their maturity (i.e., temporary fluctuations in value) along with any derivatives settled are reported in gain (loss) on derivatives in our Consolidated Statements of Operations.

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.

New Accounting Standards

Reference Rate Reform (Topic 848)—Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The FASB issued ASU 2020-04 which provides 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 ASU should help stakeholders during the global market-wide reference rate transition period. The amendments within this ASU 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. The amendments will not have a material impact on our consolidated financial statements.

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 amendments will be effective for reporting periods beginning after December 15, 2020. Early adoption is permitted. This standard will not have a material impact on our consolidated financial statements.

Adopted Standards

Measurement of Credit Losses on Financial Instruments (Topic 326). The FASB issued ASU 2016-13 which replaces current methods for evaluating impairment of financial instruments not measured at fair value, including trade accounts receivable, and certain debt securities, with a current expected credit loss model (CECL). The CECL model is expected to result in more timely recognition of credit losses. The amendment was effective for reporting periods after December 15, 2019. The adoption of this guidance did not have a material impact on our consolidated financial statements or related disclosures.

Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement. The FASB issued ASU 2018-13 to modify the disclosure requirements in Topic 820. Part of the disclosures were removed or modified, and other disclosures were added. The amendment was effective for reporting periods beginning after December 15, 2019. The adoption of this guidance did not have a material impact on our consolidated financial statements or related disclosures.

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.

Our Chapter 11 Cases allowed us to significantly reduce our level of indebtedness and our future cash interest obligations. 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	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
Net cash provided by operating activities	$ 29,807	$ 44,956	$ 269,396
Net cash used in investing activities	(2,258)	(20,139)	(394,563)
Net cash provided by (used in) financing activities	(47,775)	7,552	119,286
Net increase (decrease) cash, restricted cash, and cash equivalents	$ (20,226)	$ 32,369	$ (5,881)

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 decreased by $194.6 million in 2020 compared to 2019 primarily due to lower revenues due to lower commodity prices and lower drilling rig utilization partially offset by an increase 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 curtailed our spending in 2020, we expect that any future capital budgets would be focused on development or acquisitions of producing oil and gas properties, but not exploration.

Cash flows used in investing activities decreased by $372.2 million in 2020 compared to 2019. The change was due primarily to a decrease in capital expenditures due to a decrease in operated wells drilled and a decrease in oil and gas property acquisitions partially offset by a decrease in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities decreased by $159.5 million in 2020 compared to 2019. The decrease was primarily due to a decrease in the net borrowings and a decrease in bank overdrafts.

At December 31, 2020, we had unrestricted cash and cash equivalents totaling $12.1 million and had borrowed $99.0 million of the amounts available under the Exit Credit Agreement. We did not have any outstanding borrowings under our Superior credit agreement.

Below is a summary of certain financial information as of December 31:

	Successor		Predecessor	
	2020		2019	
	(In thousands)			
Working capital	$	2,575	$	(154,998)
Current portion of long-term debt	$	600	$	108,200
Long-term debt [1]	$	98,400	$	663,216
Shareholders' equity attributable to Unit Corporation	$	179,222	$	853,878

1. Long-term debt is net of unamortized discount and debt issuance costs for the Predecessor Period.

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 $2.6 million at December 31, 2020 and negative working capital of $155.0 million as of December 31, 2019. The increase in working capital is primarily due to more cash and cash equivalents and lower accounts payable and accrued liabilities from to the settlement of the liabilities subject to compromise partially offset by lower accounts receivable. Both the Superior credit agreement and the Exit Credit Agreement are used for working capital. At December 31, 2020, we had borrowed $99.0 million under the Exit Credit Agreement and we did not have any outstanding borrowings under our Superior credit agreement. The effect of our derivatives decreased working capital by $1.0 million as of December 31, 2020 and increased working capital by $0.6 million as of December 31, 2019.

Long-Term Debt

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 any proceeds from the disposition of certain assets be used to repay amounts outstanding.

Oil and Natural Gas Operations

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow, and the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, by worldwide oil price levels, and recently by the worldwide economic impact from the coronavirus. Domestic oil prices are primarily influenced by world oil market developments. These factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Contract Drilling Operations

Many factors influence the number of drilling rigs we have working, and the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Competition to keep qualified labor continues. Our drilling rig personnel are a key component to the overall success of our drilling services. With the present conditions in the drilling industry, we do not anticipate increases in the compensation paid to those personnel in the near term.

During 2020, most of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The continuous fluctuations in commodity prices for oil and natural gas changes demand for drilling rigs. These factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. The future demand for and the availability of drilling rigs to meet that demand will affect our future dayrates. For the Successor Period and Predecessor Period of 2020, our average dayrate was $17,807 and $18,911 per day, respectively, compared to $18,762 per day for 2019. Our average number of drilling rigs used (utilization %) for the Successor Period and Predecessor Period of 2020 were 7.2 (12%) and 11.5 (20%), respectively, compared with 24.6 (43%) in 2019. Based on the average utilization of our drilling rigs during 2020, a $100 per day change in dayrates has a $1,010 per day ($0.4 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Some of the drilling services we perform on our properties are, depending on the timing of those services, deemed associated with acquiring an ownership interest in the property. In those cases, revenues and expenses for those services are eliminated in our statement of operations, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. By providing drilling services for the oil and natural gas segment, we eliminated revenue of $15.8 million during 2019 from our contract drilling segment and eliminated the associated operating expense of $14.2 million yielding $1.6 million as a reduction to the carrying value of our oil and natural gas properties. We did not eliminate any revenue or expense in 2020.

There were no impairment triggering events identified in the Successor Period of 2020 for our contract drilling assets.

Mid-Stream Operations

This segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 11 processing plants, 17 gathering systems, and approximately 2,090 miles of pipeline. Its operations are in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. This segment enhances our ability to gather and market not only our own natural gas and NGLs but also natural gas and NGLs owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the Successor Period of 2020, Predecessor Period of 2020, and the year 2019, Superior purchased $10.6 million, $11.8 million, and $40.6 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $1.2 million, $2.8 million, and $6.9 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

Our mid-stream segment gathered an average of 367,302 Mcf per day in 2020 compared to 435,646 Mcf per day in 2019. It processed an average of 150,559 Mcf per day in 2020 compared to 164,482 Mcf per day in 2019, and sold NGLs of 555,454 gallons per day in 2020 compared to 625,873 gallons per day in 2019. Gas gathering volumes per day in 2020 decreased primarily due to lower volumes from most of our major gathering and processing systems resulting from declining wellhead volumes and fewer wells connected except from the Cashion facility. Volumes processed and NGLs sold in 2020 decreased mainly due to lower volumes from our processing facility in the Texas panhandle resulting from declines and not connecting any new wells in 2020.

Our Credit Agreements and Predecessor Debt

Exit Credit Agreement. On the Effective Date, under the Plan, we entered into an amended and restated credit agreement (the Exit Credit Agreement), providing for a $140.0 million senior secured revolving credit facility and a $40.0 million senior secured term loan facility, among (i) the company, UDC, and UPC, (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, and (iv) BOKF, NA dba Bank of Oklahoma as administrative agent and collateral agent (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.

The Exit Credit Agreement requires that we comply with certain financial ratios, including a covenant that we will not permit the Net Leverage Ratio (as defined in the Exit Credit Agreement) as of the last day of the fiscal quarters ending (i) December 31, 2020 and March 31, 2021, to be greater than 4.00 to 1.00, (ii) June 30, 2021, September 30, 2021, December 31, 2021, March 31, 2022, and June 30, 2022, to be greater than 3.75 to 1.00, and (iii) September 30, 2022 and any fiscal quarter thereafter, to be greater than 3.50 to 1.00. In addition, beginning with the fiscal quarter ending December 31, 2020, we 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 0.50 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, restrict certain asset sales and the related use of proceeds, and require certain hedging activities. The Exit Credit Agreement further requires that we 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. For the quarter ended September 30, 2020, the syndicate banks allowed for an extension.

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 our ownership interests in Superior Pipeline Company, L.L.C.

On the Effective Date, we had (i) $40.0 million in principal amount of Term Loans outstanding, (ii) $92.0 million in principal amount of Revolving Loans outstanding, and (iii) approximately $6.7 million of outstanding letters of credit. At December 31, 2020, we had $0.6 million and $98.4 million outstanding current and long-term borrowings, respectively, under the Exit Credit Agreement.

Predecessor's Credit Agreement. Before the filing of the Chapter 11 Cases, the 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). The Debtors' filing of the Chapter 11 Cases constituted an event of default that accelerated the Debtors' obligations under the Unit credit agreement and the indenture governing the Notes. Due to the Credit Agreement Extension Condition, our debt associated with the Unit credit agreement is reflected as a current liability in our Consolidated Balance Sheets as of December 31, 2019. The classification as a current liability due to the Credit Agreement Extension Condition was based on the uncertainty regarding our ability to repay or refinance the Notes before November 16, 2020. In addition, on May 22, 2020, the lenders' remaining commitments under the Unit credit agreement were terminated.

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 termination of the remaining commitments of the lenders under the Unit credit agreement, the unamortized debt issuance costs of $2.4 million were written off during the second quarter of 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.

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.

On the Effective Date, each lender under the Unit credit agreement and 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 exchange for that lender's allowed claims under the 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 Superior credit agreement). 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) third day LIBOR plus 1.00%) 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 that index no longer exists or accurately reflects the rate available to the Administrative Agent in the London Interbank Market, the 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. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio of not greater than 4.00 to 1.00. Additionally, the Superior credit agreement contains several customary covenants that, among other things, restrict (subject to certain exceptions) Superior's ability to incur additional indebtedness, create additional liens on its assets, make investments, pay distributions, enter into sale and leaseback transactions, engage in certain transactions with affiliates, engage in mergers or consolidations, enter into hedging arrangements, and acquire or dispose of assets. As of December 31, 2020, Superior was in compliance with the Superior credit agreement covenants.

Borrowings from the Superior credit agreement will be used to fund capital expenditures and acquisitions, provide general working capital, and for letters of credit for Superior.

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.

6.625% Senior Subordinated Notes. The 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 Notes.

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

DIP Credit Agreement. As contemplated by the Restructuring Support Agreement between the company and certain of the 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 the $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. On the Effective Date, 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 received (or was entitled to receive) 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 – Emergence From Voluntary Reorganization Under Chapter 11.

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 its pro rata share of seven-year warrants (Warrants) to purchase an aggregate of 12.5% of the shares of New Common Stock, at an aggregate exercise price equal to the $650.0 million principal amount of the Notes plus interest thereon to the May 15, 2021 maturity date of the Notes. On the Effective Date, we entered into a Warrant Agreement (Warrant Agreement) with American Stock Transfer & Trust Company, LLC. 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. On December 21, 2020, we issued approximately 1.8 million Warrants to the holders of the Old Common Stock that did not opt out of the releases under the Plan and owned their shares of Old Common Stock in street name through the facilities of the DTC. On February 11, 2021, we issued 42,511 Warrants to certain holders of the Old Common Stock that did not opt out of the releases under the Plan and owned their shares through direct registration with the company's transfer agent (Direct Registration). We expect to issue approximately 37,000 additional 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. Under the Plan, additional Warrants will be issued in book-entry form through the facilities of the DTC, and each holder owning shares of Old Common Stock through Direct Registration must provide that holder's brokerage account information to the company to receive such holder's distribution of Warrants. Holders of shares of the Old Common Stock that owned shares through Direct Registration should contact Prime Clerk, LLC at (877) 720-6581 (Toll Free) or (646) 979-4412 (Local) to obtain the forms necessary to receive their distribution. Any distribution not made will be deemed forfeited at the first anniversary of the Effective Date.

Capital Requirements

Oil and Natural Gas Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures in our oil and natural gas are discretionary and directed toward growth. Any decision 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. During the Successor Period and Predecessor Period of 2020, we participated in the drilling of three wells (0.30 net wells) and 16 wells (0.35 net wells), respectively, compared to 115 gross wells (29.15 net wells) in 2019.

During the Successor Period of 2020, capital expenditures by this segment for oil and gas properties on the full cost method, excluding a $1.7 million reduction in the ARO liability and no acquisitions, totaled $4.0 million. During the Predecessor Period of 2020, capital expenditures, excluding a $29.2 million reduction in the ARO liability and $0.4 million in acquisitions (including associated ARO), totaled $5.4 million compared to 2019 capital expenditures of $264.9 million (excluding a $0.1 million reduction in the ARO liability and $3.7 million in acquisitions).

For 2021, we plan to focus our capital expenditures on development of proved properties and acquisition of proved and producing properties.

We sold non-core oil and natural gas assets, net of related expenses, for $0.4 million, $1.2 million and $21.8 million during the Successor Period, and Predecessor Period of 2020, and the year 2019, respectively. Proceeds from those dispositions reduced the net book value of our full cost pool with no gain or loss recognized. We plan to pursue additional dispositions of non-core assets in 2021.

Contract Drilling Dispositions, Acquisitions, and Capital Expenditures. During 2019, we completed construction and placed into service our 12th, 13th, and 14th BOSS drilling rigs. These drilling rigs were subject to long-term contracts with third party operators.

We did not build any new BOSS drilling rigs during 2020. We have no commitments or current plans to build any additional BOSS drilling rigs in 2021.

For 2021, capital expenditures are expected to primarily be for maintenance capital on operating drilling rigs and the possible conversion of certain SCR drilling rigs to AC drilling rigs if practicable. We also plan to pursue the disposal or sale of our non-core, idle drilling rig fleet. For 2020, we incurred $0.6 million during the Successor Period and $2.4 million during the Predecessor Period in capital expenditures, compared to $40.6 million in 2019.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. At the Cashion processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2020 averaged approximately 64.2 MMcf per day and total production of natural gas liquids averaged approximately 252,000 gallons per day. For 2020, we continued to connect new wells to this system for third party producers. Since the first of 2020, we connected 18 new wells to this system from producers. The total processing capacity of the Cashion system is 105 MMcf per day.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for the fourth quarter of 2020 was 131.7 MMcf per day and average gathered volume for 2020 was 152.3 MMcf per day. During 2020, we connected four new infill wells to an existing well pad.

Also, in the Appalachian area at our Snow Shoe gathering system, the average gathering volume for the fourth quarter was 2.5 MMcf per day and the average gathered volume for 2020 was 3.0 MMcf per day. In 2020, we did not connect any new wells to this system. At Snow Shoe for 2020, we also charged a demand fee based on a volume of 55 MMcf per day. This demand fee volume will be reduced in 2021 to 51 MMcf per day. Additionally, in 2020, we recognized a shortfall fee from a producer on this system for $5.3 million. This fee will be invoiced in the first quarter of 2021.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the fourth quarter of 2020 was 46.6 MMcf per day and average total throughput volume for 2020 was 51.3 MMcf per day. Total average production of natural gas liquids for the fourth quarter of 2020 decreased to approximately 110,000 gallons per day due to operating in ethane rejection. Total production of natural gas liquids for 2020 averaged approximately 152,000 gallons per day. The total processing capacity of the Hemphill system is 135 MMcf per day. In 2020, we did not connect any new wells to this system. Currently there are no active rigs in the area, and we do not anticipate any new well connects for this system.

At the Segno gathering system located in East Texas, the average throughput volume for the fourth quarter of 2020 decreased to approximately 31.0 MMcf per day due to declining production volume along with no new drilling activity in the area. For 2020, the average throughput volume for this system was approximately 40 MMcf per day. During 2020, we did not connect any new wells to this system.

Our mid-stream segment incurred $1.3 million during the Successor Period and $9.3 million during the Predecessor Period in capital expenditures as compared to $64.4 million in 2019, which included $16.1 million for an acquisition. For 2021, our estimated capital expenditures will be approximately $15.0 million which we expect to be primarily for the maintenance and operation of our assets and connection of new wells.

Contractual Commitments

At December 31, 2020, we had these contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt [1]	$ 118,637	$ 6,494	$ 12,696	$ 99,447	$ —
Operating leases [2]	5,520	4,075	1,376	16	53
Finance lease interest and maintenance [3]	558	558	—	—	—
Firm transportation commitments [4]	1,379	1,020	359	—	—
Total contractual obligations	$ 126,094	$ 12,147	$ 14,431	$ 99,463	$ 53

1. See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Exit Facility and includes interest calculated using our December 31, 2020 interest rates of 6.6% for our Exit Credit Agreement. The Exit Credit Agreement has a maturity date of March 1, 2024 and had an outstanding balance as of December 31, 2020 of $99.0 million ($0.6 million is reflected as a current liability in our Consolidated Balance Sheets). The Superior credit agreement has a maturity date of May 10, 2023 and had no outstanding balance as of December 31, 2020.

2. We lease certain office space, land, and equipment, including pipeline equipment and office equipment under the terms of operating leases under ASC 842 expiring through March 2031. We also have short-term lease commitments of $0.2 million. This is lease office space or yards in Oklahoma City, Oklahoma; Houston and Odessa, Texas; Englewood, Colorado; and Pinedale, Wyoming under the terms of operating leases expiring through January 2022. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

3. Maintenance and interest payments are included in our finance lease agreements. The finance leases are discounted using annual rates of 4.0%. Total maintenance and interest remaining are $0.5 million and less than $0.1 million, respectively.

4. We have firm transportation commitments to transport our natural gas from various systems for approximately $1.0 million over the next twelve months and $0.4 million for the one year thereafter.

During the second quarter of 2018, as part of the Superior transaction (see Note 19 – Variable Interest Entity Arrangements), we entered into a contractual obligation committing us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. For each dollar of the $150.0 million we do not spend (over the three-year period), we would forgo receiving $0.58 of future distributions from our ownership interest in our consolidated mid-stream subsidiary. At December 31, 2020, if we elected not to drill or spend any additional money in the designated area before December 31, 2021, the maximum amount we could forgo from distributions would be $72.6 million. The total amount spent towards the $150.0 million as of December 31, 2020 was $24.8 million. We do not anticipate meeting the contractual obligation over the remaining commitment period.

At December 31, 2020, we also had these commitments and contingencies that could create, increase or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	**Total Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Separation benefit plans (1)	$ 4,201	$ 1,543	Unknown	Unknown	Unknown
ARO liability (2)	$ 23,356	$ 2,121	$ 3,240	$ 3,159	$ 14,836
Gas balancing liability (3)	$ 3,997	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (4)	$ 10,164	$ 1,705	Unknown	Unknown	Unknown
Finance lease obligations (5)	$ 3,216	$ 3,216	$ —	$ —	$ —
Contract liability (6)	$ 4,172	$ 2,583	$ 1,560	$ 12	$ 18
Other long-term liabilities (7)	$ 1,321	$ —	$ 1,321	$ —	$ —
Derivative liabilities—commodity hedges	$ 5,706	$ 1,047	$ 4,659	$ —	$ —

1. 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 allow 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. In accordance with the Plan, the New Separation Benefit Plan is 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 provides that eligible employees will be entitled to two weeks of severance pay per year of service, with a minimum of four weeks and a maximum of 13 weeks of severance pay.
2. When a well is drilled or acquired, under ASC 410 "Accounting for Asset Retirement Obligations," we record the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).
3. We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.
4. We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.
5. This amount includes commitments under finance lease arrangements for compressors in our mid-stream segment.
6. We have recorded a liability related to the timing of the revenue recognized on certain demand fees in our mid-stream segment.
7. Due to the issuance of the Coronavirus Aid, Relief, and Economic Security Act (CARES Act), we have deferred our FICA tax payment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, or natural gas production. Any change in the fair value of all our derivatives are reflected in our Consolidated Statements of Operations.

Commodity Derivatives. Our commodity derivatives reduce our exposure to price volatility and manage price risks. 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, 2020, based on our fourth quarter 2020 average daily production, the approximated percentages of our production under derivative contracts were as follows:

	2021	2022	2023
Daily oil production	66 %	46 %	26 %
Daily natural gas production	55 %	45 %	25 %

For commodities subject to derivative contracts, those contracts limit the risk of downward price movements. But they also limit increases in future revenues that would otherwise result from price movements above the contracted prices.

Derivative transactions carry with them the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our evaluation at December 31, 2020, we believe the risk of non-performance by our counterparties is not material. At December 31, 2020, the fair values of the net assets we had with each of the counterparties to our commodity derivative transactions was:

	December 31, 2020
	(In millions)
Bank of Oklahoma	$ (5.4)
Bank of Montreal	(0.3)
Total net liabilities	$ (5.7)

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our Consolidated Balance Sheets. At December 31, 2020, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative liabilities of $1.0 million and long-term derivative liabilities of $4.7 million. At December 31, 2019, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.6 million and long-term derivative liabilities of less than $0.1 million.

All derivatives are recognized on the balance sheet and measured at fair value. Any changes in our derivatives' fair value before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Consolidated Statements of Operations.
These gains (losses) as of the periods indicated were:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
Gain (loss) on derivatives, included are amounts settled during the period of ($1,133), ($4,244), and $16,196, respectively	$ (985)	$ (10,704)	$ 4,225

Stock and Incentive Compensation

During 2020, we did not grant any awards. 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 since we are currently not drilling.

During 2019, we granted awards covering 1,500,213 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over the awards' three-year vesting period. These awards were granted as retention incentive awards and are being recognized over their two- and three-year vesting periods.

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 Predecessor Period.

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.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships.

We were the general partner of 13 oil and natural gas partnerships formed privately or publicly. Each partnership's revenues and costs were shared under formulas set out in that partnership's agreement. The partnerships repaid us for contract drilling, well supervision, and general and administrative expense. Related party transactions for contract drilling and well supervision fees were the related party's share of such costs. These costs were billed the same as billings to unrelated third parties for similar services. General and administrative reimbursements consisted of direct general and administrative expense incurred on the related party's behalf and indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and were considered by us to be reasonable. Our proportionate share of assets, liabilities, and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements for the years prior to termination. The partnerships were terminated during the second quarter of 2019 with an effective date of January 1, 2019 at a repurchase cost of $0.6 million, net of Unit's interest.

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.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we are subject to various contractual commitments.

Results of Operations

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

	Successor	Predecessor		
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	Year Ended December 31, 2019	Percent Change [1]
Total revenue	$ 133,528	$ 276,957	$ 674,634	(39) %
Net loss	$ (13,988)	$ (890,624)	$ (553,828)	(63) %
Net income attributable to non-controlling interest	$ 4,152	$ 40,388	$ 51	NM
Net loss attributable to Unit Corporation	$ (18,140)	$ (931,012)	$ (553,879)	(71) %
Oil and Natural Gas:				
Revenue	$ 57,578	$ 103,439	$ 325,797	(51) %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 25,256	$ 117,691	$ 135,124	6 %
Depreciation, depletion, and amortization	$ 14,869	$ 68,762	$ 168,651	(50) %
Impairment of oil and natural gas properties	$ 26,063	$ 393,726	$ 559,867	(25) %
Average oil price received (Bbl)	$ 37.29	$ 31.98	$ 57.49	(45) %
Average oil price per barrel received excluding derivatives	$ 39.23	$ 35.14	$ 55.13	(36) %
Average NGL price received (Bbl)	$ 9.28	$ 4.83	$ 12.42	(59) %
Average NGLs price per barrel received excluding derivatives	$ 9.28	$ 4.83	$ 12.42	(59) %
Average natural gas price received (Mcf)	$ 1.92	$ 1.14	$ 2.04	(41) %
Average natural gas price per mcf received excluding derivatives	$ 1.91	$ 1.11	$ 1.88	(38) %
Oil production (MBbls)	626	1,562	3,208	(32) %
NGLs production (MBbls)	1,045	2,399	4,773	(28) %
Natural gas production (MMcf)	11,006	26,563	53,065	(29) %
Depreciation, depletion, and amortization rate (Boe)	$ 4.21	$ 7.77	$ 9.66	(30) %
Contract Drilling:				
Revenue	$ 19,413	$ 73,519	$ 168,383	(45) %
Operating costs excluding depreciation	$ 13,852	$ 51,810	$ 115,998	(43) %
Depreciation	$ 2,102	$ 15,544	$ 51,552	(66) %
Impairment of contract drilling equipment	$ —	$ 410,126	$ —	— %
Impairment of goodwill	$ —	$ —	$ 62,809	(100) %
Percentage of revenue from daywork contracts	100 %	100 %	100 %	— %
Average number of drilling rigs in use	7.2	11.5	24.6	(59) %
Total drilling rigs available for use at the end of the period	58	58	58	— %
Average dayrate on daywork contracts	$ 17,807	$ 18,911	$ 18,762	(1) %

	Successor	Predecessor		
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	Year Ended December 31, 2019	Percent Change [1]
Mid-Stream:				
Revenue	$ 56,537	$ 99,999	$ 180,454	(13) %
Operating costs excluding depreciation and amortization	$ 42,169	$ 68,045	$ 133,606	(18) %
Depreciation and amortization	$ 10,659	$ 29,371	$ 47,663	(16) %
Impairment of gas gathering and processing equipment and line fill	$ —	$ 63,962	$ 3,040	NM
Gas gathered—Mcf/day	324,892	388,506	435,646	(16) %
Gas processed—Mcf/day	135,615	158,031	164,482	(8) %
Gas liquids sold—gallons/day	441,761	612,301	625,873	(11) %
Number of natural gas gathering systems	17	18	19	(7) %
Number of processing plants	11	11	11	— %
Corporate and other:				
Loss on abandonment of assets	$ —	$ 18,733	$ —	— %
General and administrative expense	$ 6,702	$ 42,766	$ 38,246	29 %
Other depreciation	$ 332	$ 1,819	$ 7,707	(72) %
Gain (loss) on disposition of assets	$ 619	$ 89	$ (3,502)	120 %
Other income (expense):				
Interest income	$ —	$ 58	$ 49	18 %
Interest expense, net	$ (3,275)	$ (22,882)	$ (37,061)	(29) %
Reorganization costs, net	$ (2,273)	$ 133,975	$ —	— %
Write-off debt issuance costs	$ —	$ (2,426)	$ —	— %
Gain (loss) on derivatives	$ (985)	$ (10,704)	$ 4,225	NM
Other	$ 100	$ 2,034	$ (236)	NM
Income tax benefit	$ (302)	$ (14,630)	$ (132,326)	89 %
Average interest rate	6.8 %	5.5 %	6.4 %	(14) %
Average long-term debt outstanding	$ 121,740	$ 526,167	$ 744,978	(35) %

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 decreased $164.8 million or 51% in 2020 as compared to 2019 due primarily to lower commodity prices and production. Oil production decreased 32%, NGLs production decreased 28%, and natural gas production decreased 29%. Average oil prices between the comparative years decreased 45% to $31.61 per barrel, NGLs prices decreased 59% to $5.10 per barrel, and natural gas prices decreased 41% to $1.20 per Mcf.

Oil and natural gas operating costs increased $7.8 million or 6% between the comparative years of 2020 and 2019 primarily due to higher G&A expenses from the litigation settlements and no longer capitalizing directly related overhead costs in 2020 partially offset by lower LOE and gross production taxes.

DD&A decreased $85.0 million or 50% primarily due to a 30% decrease in our DD&A rate and a 29% decrease in equivalent production. The decrease in our DD&A rate resulted primarily from the effect of the ceiling test write-downs during 2020.

During the Successor Period of 2020, we recorded 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 forward prices for our Fresh Start fair value estimates. During the Predecessor Period of 2020, we recorded non-cash ceiling test write-downs of $393.7 million, pre-tax ($346.6 million, net of tax) due to the reduction for the 12-month average commodity prices and the impairment of our unproved oil and gas properties. We also recorded an expense of $17.6 million related to the write-down of our salt water disposal asset that we considered abandoned. During 2019, we recorded non-cash ceiling test write-downs of $559.4 million, pre-tax ($422.4 million, net of tax) due to the reduction of the 12-month average commodity prices and the removal of proved undeveloped reserves due to the uncertainty regarding our ability to finance future capital expenditures. We also recorded in 2019 a $0.5 million impairment on gathering systems with wells no longer producing.

Contract Drilling

Drilling revenues decreased $75.5 million or 45% in 2020 as compared to 2019. The decrease was due primarily to a 59% decrease in the average number of drilling rigs in use compared to 2019. Average drilling rig utilization decreased from 24.6 drilling rigs in 2019 to 10.1 drilling rigs in 2020.

Drilling operating costs decreased $50.3 million or 43% in 2020 compared to 2019. The decrease was due primarily to less drilling rigs operating. Contract drilling depreciation decreased $33.9 million or 66% also due primarily to less drilling rigs operating and from lower depreciable net book value due to impairments recognized in the first half of 2020.

At March 31, 2020, due to market conditions, we performed impairment testing on two asset groups which were comprised of the SCR diesel-electric drilling rigs and the 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 the first quarter of 2020. We also recorded an additional non-cash impairment charge of $3.0 million for other drilling equipment. These charges are included within impairment charges in our Consolidated Statements of Operations. No impairment was needed on the BOSS drilling rigs asset group as the undiscounted cash flows exceeded the carrying value of the asset group.

In 2019, we recognized goodwill impairment charges of $62.8 million, pre-tax ($59.8 million, net of tax) representing all our goodwill which is related to our contract drilling segment.

Mid-Stream

Our mid-stream revenues decreased $23.9 million or 13% in 2020 as compared to 2019 primarily due to decreased NGLs, gas, and condensate sales as a result of lower prices and lower volumes resulting from fewer wells connected and declining wellhead volumes. Gas processing volumes per day decreased 8% between the comparative years primarily due to lower purchased volumes from our processing facility in the Texas panhandle. Gas gathering volumes per day decreased 16% primarily due to lower volumes from most of our major gathering and processing systems resulting from fewer wells connected and declining wellhead volumes except from the Cashion facility.

Operating costs decreased $23.4 million or 18% in 2020 compared to 2019 primarily due to a decrease in purchase prices. Depreciation and amortization decreased $7.6 million or 16% primarily due to lower depreciable net book value from the impairment recognized in the first quarter of 2020.

During the first quarter of 2020, we determined that the carrying value of certain long-lived asset groups located 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. Based on the estimated fair value of the asset groups, we recorded non-cash impairment charges of $64.0 million. In 2019, we recorded a $3.0 million impairment due to decreased value of line fill due to lower prices and from the retirement of two older systems.

Loss on Abandonment of Assets

During the first quarter of 2020, we evaluated the carrying value of our salt water disposal assets. Based on our revised forecast of asset utilization, we determined certain assets were no longer expected to be used and wrote off certain salt water disposal assets that we now consider abandoned. We recorded expense of $17.6 million related to the write-down of our salt water disposal asset in the first quarter of 2020. In the third quarter of 2020, we recorded expense of $1.2 million related to the write-down of our drilling line asset.

General and Administrative

General and administrative expenses increased $11.2 million or 29% in 2020 compared to 2019 primarily due to consulting fees paid prior to filing for bankruptcy and costs incurred for separation benefits provided to employees that were part of our reduction in force in April 2020. We incurred $20.2 million in advisory and restructuring fees.

Gain (Loss) on Disposition of Assets

(Gain) loss on disposition of assets decreased $4.2 million in 2020 compared to 2019. The loss in 2020 was primarily related to the sale of vehicles, drilling rigs, and other drilling equipment, while the gain in 2019 was primarily from the retirement of old rig inventory.

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $10.9 million between the comparative years of 2020 and 2019. We capitalized interest based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Because we are not currently undergoing any capital projects, we had no capitalized interest for 2020 compared to $16.2 million in 2019 that was netted against our gross interest of $53.2 million for 2019. Our average interest rate increased due to the new Exit Credit Agreement terms and our average debt outstanding was decreased primarily due to the Notes being settled with the Plan.

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. For more detail, see Note 2 – Emergence From Voluntary Reorganization Under Chapter 11.

Write-off of Debt Issuance Costs

Due to the remaining commitments of the Unit credit agreement being terminated by the lenders, the unamortized debt issuance costs of $2.4 million were written off during the second quarter of 2020.

Gain (Loss) on Derivatives

Gain (loss) on derivatives decreased $15.9 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Benefit

Income tax benefit decreased $117.4 million in 2020 compared to 2019. We recognized an income tax benefit of $14.9 million in 2020 compared to an income tax benefit of $132.6 million in 2019. The 2020 income tax benefit was lower primarily due to the recognition of a full valuation allowance against our net deferred tax assets due to our emergence from bankruptcy in 2020 and fresh start accounting principles.

Our effective tax rate was 1.6% for 2020 compared to 19.3% for 2019. The effective tax rate for the current year was lower as compared to 2019 because of the recognition of a full valuation allowance as described above. The increase in our valuation allowance was due to determining it was more likely than not that the net deferred tax assets would not be fully realizable. We paid no federal or state income taxes during 2020.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Our operations are exposed to market risks primarily because of changes in the prices for natural gas and oil and interest rates.

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 2020 production, a $0.10 per Mcf change in what we are paid for our natural gas production would cause a corresponding $254,000 per month ($3.1 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $147,000 per month ($1.8 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $260,000 per month ($3.1 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, 2020, these non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'21 - Dec'21	Natural gas - basis swap	30,000 MMBtu/day	$(0.215)	NGPL TEXOK
Jan'21 - Oct'21	Natural gas - swap	50,000 MMBtu/day	$2.818	IF - NYMEX (HH)
Nov'21 - Dec'21	Natural gas - swap	45,000 MMBtu/day	$2.900	IF - NYMEX (HH)
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'21 - Dec'21	Crude oil - swap	3,000 Bbl/day	$44.650	WTI - NYMEX
Jan'22 - Dec'22	Crude oil - swap	2,300 Bbl/day	$42.250	WTI - NYMEX
Jan'23 - Dec'23	Crude oil - swap	1,300 Bbl/day	$43.600	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 2020, an 1% increase in the interest rate on the outstanding borrowings under these facilities would reduce our annual pre-tax cash flow by approximately $1.3 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 sheet of Unit Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2020 (Successor), the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity, and cash flows for 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, 2020, and the results of its operations and its cash flows 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 3.

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 audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board ("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 audit 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 audit 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 audit 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 audit provides a reasonable basis for our opinion.

Critical audit matters

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

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 4 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 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 sensitive inputs and assumptions used to determine proved reserve volumes and other financial inputs and assumptions, including certain assumptions that are derived from the Company's accounting records. These assumptions included historical pricing differentials, future operating costs, estimated future capital costs, and ownership interests.
- We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis. Specifically, our audit procedures involved testing management's assumptions as follows:
  - We compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials.
  - We evaluated the models used to estimate the future operating costs at year-end and compared the models to historical operating costs.
  - We evaluated the ownership interests used in the reserve report by inspecting lease and title records on a sample basis.
  - We applied analytical procedures to the reserve report by comparing the reserve report to historical actual results and to the prior year reserve report.

Emergence from bankruptcy — application of fresh start accounting

As described further in Notes 2 and 3, on September 3, 2020, the Company emerged from Chapter 11 bankruptcy. In connection with its emergence, the Company qualified for and adopted fresh start accounting. Management calculated a reorganization value, which represents the estimated fair value of the Successor's assets before considering liabilities and allocated the value to its individual assets based on their estimated fair values with the assistance of a third-party valuation specialist. We identified the application of fresh start accounting to be a critical audit matter.

The principal consideration for our determination that the Company’s application of fresh start accounting is a critical audit matter is that fresh start accounting requires assets and liabilities, including deferred income taxes, to be remeasured as described above. The remeasurement required management to make significant judgments in determining the relative fair values of assets and liabilities that existed at the emergence from bankruptcy and to record the income tax impact of the

Company's emergence from bankruptcy and our audit procedures involved increased audit effort due to the high degree of auditor judgment necessary.

Our audit procedures related to the fair value measurements and income tax adjustments resulting from the Company's application of fresh start accounting included the following, among others.

- With the assistance of our valuation specialists, we evaluated the qualifications and objectivity of the Company's third-party valuation specialists that assisted management in applying fresh start accounting.
- We evaluated the methodology used by management to estimate the fair values of the Successor's assets upon emergence from bankruptcy and tested certain key data and assumptions impactful to those valuations.
- We performed procedures similar to those described above on the estimated oil and natural gas reserves that were a key input to the valuation of proved oil and natural gas properties at emergence from bankruptcy.
- We assessed the appropriateness of market data, such as recent transactions, comparable multiples and discount rates, used by the Company's third-party valuation specialists to value other tangible assets of the Successor.
- We evaluated the key assumptions used in certain discounted cash flow analysis supporting asset values including forecasted revenues, operating income, and discount rates by comparing to historical results and comparable transactions.
- With the assistance of our income tax specialists, we evaluated the income tax adjustments recorded by management to reflect the effects of the bankruptcy reorganization and the application of fresh start accounting. Our procedures included the following, among others:
  - We evaluated the qualifications and objectivity of the Company's third-party income tax specialists that assisted management in applying fresh start accounting.
  - We evaluated management's judgments made with respect to changes in tax attributes, net operating loss carryforwards, and other asset basis and tax election changes that resulted from the application of fresh start accounting.
  - We tested management's calculation of cancellation of debt income, including the computations of adjusted issue price.
  - We tested the completeness and accuracy of data used by management and the Company's income tax specialists to measure the deferred income taxes of the Successor Company following emergence from bankruptcy.

Investment in Superior Pipeline Company, L.L.C. — accounting for a variable interest entity

As described further in Note 19, the Company accounts for its investment in Superior Pipeline Company, L.L.C. ("Superior") as a variable interest entity ("VIE"). Management determined that the Company is the primary beneficiary of the VIE and therefore consolidates the accounts of Superior and records a non-controlling interest related to the other owner's interest in Superior. The determination that the Company is the primary beneficiary of the VIE results in material amounts of assets, liabilities, revenues, and expenses being recorded in the Company's financial statements. We identified the accounting for the Company's investment in Superior as a critical audit matter.

The principal consideration for our determination that the accounting for the Company's investment in Superior is a critical audit matter is that the determination of which owner of Superior represents the primary beneficiary of the VIE required management to make a subjective assessment of what activities are the most impactful to the VIE and which partner has the power to direct those activities. Management's assessment process included evaluating rights of each owner as outlined in various organizational documents and management services agreements which govern the operations of the VIE. Auditing management's conclusions with respect to the accounting for the VIE involved complex auditor judgment.

Our audit procedures related to the accounting for the Company's investment in Superior included the following, among others.

- We inspected certain documents of Superior pertaining to how the entity is managed and governed to test management's assertion regarding various rights of each owner.
- We inquired of management and the owners regarding the business purpose of the VIE and who directs the activities that are most impactful to the VIE.
- We consulted with our national office resources to assess management's conclusions that Superior is a VIE and that the Company is the primary beneficiary.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 31, 2021

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

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Unit Corporation

Opinion on the Financial Statements

We have audited the consolidated balance sheet, statements of operations, comprehensive income (loss), changes in shareholders' equity, and cash flows of Unit Corporation and its subsidiaries (the "Company") for the year ended December 31, 2019, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of the Company for the year ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Substantial Doubt About the Company's Ability to Continue as a Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has incurred significant losses, is in a negative working capital position, and does not anticipate that forecasted cash and available credit capacity will be sufficient to meet their commitments over the next twelve months, which raises substantial doubt about its ability to continue as a going concern. Management's plan in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. 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 of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 16, 2020

We served as the Company's auditor from 1989 to 2020.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Successor	Predecessor
	December 31, 2020	December 31, 2019
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12,145	$ 571
Restricted cash	569	—
Accounts receivable, net of allowance for doubtful accounts of $3,783 and $2,332 at December 31, 2020 and December 31, 2019, respectively	57,846	82,656
Materials and supplies	—	449
Current derivative asset (Note 15)	—	633
Current income taxes receivable	1,150	1,756
Assets held for sale (Note 4)	—	5,908
Prepaid expenses and other	11,212	13,078
Total current assets	82,922	105,051
Property and equipment:		
Oil and natural gas properties, on the full cost method:		
Proved properties	238,581	6,341,582
Unproved properties not being amortized	1,591	252,874
Drilling equipment	63,687	1,295,713
Gas gathering and processing equipment	251,404	824,699
Saltwater disposal systems	—	69,692
Corporate land and building	32,635	59,080
Transportation equipment	3,130	29,723
Other	9,961	57,992
	600,989	8,931,355
Less accumulated depreciation, depletion, amortization, and impairment	54,189	6,978,669
Net property and equipment	546,800	1,952,686
Right of use asset (Note 17)	5,592	5,673
Other assets	14,389	26,642
Total assets [(1)]	$ 649,703	$ 2,090,052

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (Continued)

	Successor December 31, 2020	Predecessor December 31, 2019
	(In thousands except share and par value amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 40,829	$ 84,481
Accrued liabilities (Note 8)	21,743	46,562
Current operating lease liability (Note 17)	4,075	3,430
Current portion of long-term debt (Note 9)	600	108,200
Current derivative liabilities (Note 15)	1,047	—
Warrant liability (Note 2)	885	—
Current portion of other long-term liabilities (Note 9)	11,168	17,376
Total current liabilities	80,347	260,049
Long-term debt less debt issuance costs (Note 9)	98,400	663,216
Non-current derivative liabilities (Note 15)	4,659	27
Operating lease liability (Note 17)	1,445	2,071
Other long-term liabilities (Note 9)	39,259	95,341
Deferred income taxes (Note 11)	—	13,713
Commitments and contingencies (Note 18)		
Shareholders' equity:		
Predecessor preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued at December 31, 2019	—	—
Successor preferred stock, $0.01 par value, 1,000,000 shares authorized, none issued at December 31, 2020	—	—
Predecessor common stock, $0.20 par value, 175,000,000 shares authorized, 55,443,393 shares issued as of December 31, 2019	—	10,591
Successor common stock, $0.01 par value, 25,000,000 shares authorized, 12,000,000 shares issued as of December 31, 2020	120	—
Predecessor capital in excess of par value	—	644,152
Successor capital in excess of par value	197,242	—
Retained earnings (deficit)	(18,140)	199,135
Total shareholders' equity attributable to Unit Corporation	179,222	853,878
Non-controlling interests in consolidated subsidiaries	246,371	201,757
Total shareholders' equity	425,593	1,055,635
Total liabilities and shareholders' equity [1]	$ 649,703	$ 2,090,052

1. 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 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. Unit Corporation's consolidated total assets as of December 31, 2019 include current and long-term assets of its variable interest entity (VIE) (Superior) of $28.8 million and $434.3 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated total liabilities as of December 31, 2019 include current and long-term liabilities of the VIE of $32.2 million and $26.0 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. See Note 19 – Variable Interest Entity Arrangements.

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
	(In thousands except per share amounts)		
Revenues:			
Oil and natural gas	$ 57,578	$ 103,439	$ 325,797
Contract drilling	19,413	73,519	168,383
Gas gathering and processing	56,537	99,999	180,454
Total revenues	133,528	276,957	674,634
Expenses:			
Operating costs:			
Oil and natural gas	25,256	117,691	135,124
Contract drilling	13,852	51,810	115,998
Gas gathering and processing	42,169	68,045	133,606
Total operating costs	81,277	237,546	384,728
Depreciation, depletion, and amortization	27,962	115,496	275,573
Impairments (Note 4)	26,063	867,814	625,716
Loss on abandonment of assets	—	18,733	—
General and administrative	6,702	42,766	38,246
(Gain) loss on disposition of assets	(619)	(89)	3,502
Total operating expenses	141,385	1,282,266	1,327,765
Loss from operations	(7,857)	(1,005,309)	(653,131)
Other income (expense):			
Interest, net	(3,275)	(22,824)	(37,012)
Write-off debt issuance costs	—	(2,426)	—
Gain (loss) on derivatives	(985)	(10,704)	4,225
Reorganization items, net	(2,273)	133,975	—
Other	100	2,034	(236)
Total other income (expense)	(6,433)	100,055	(33,023)
Loss before income taxes	(14,290)	(905,254)	(686,154)
Income tax benefit:			
Current	(302)	(917)	(1,281)
Deferred	—	(13,713)	(131,045)
Total income taxes	(302)	(14,630)	(132,326)
Net loss	(13,988)	(890,624)	(553,828)
Net income attributable to non-controlling interest	4,152	40,388	51
Net loss attributable to Unit Corporation	$ (18,140)	$ (931,012)	$ (553,879)
Net loss attributable to Unit Corporation per common share (Note 7):			
Basic	$ (1.51)	$ (17.45)	$ (10.48)
Diluted	$ (1.51)	$ (17.45)	$ (10.48)

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
Net loss	$ (13,988)	$ (890,624)	$ (553,828)
Other comprehensive income (loss), net of taxes:			
Reclassification adjustment for write-down of securities, net of tax of $0, $0, and $(47)	—	—	481
Comprehensive loss	(13,988)	(890,624)	(553,347)
Less: Comprehensive income attributable to non-controlling interest	4,152	40,388	51
Comprehensive loss attributable to Unit Corporation	$ (18,140)	$ (931,012)	$ (553,398)

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2019 and Predecessor Period and Successor Period of 2020

	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Non-controlling Interest in Consolidated Subsidiaries	Total
			(In thousands except per share amounts)			
Balances, January 1, 2019	10,414	628,108	(481)	752,840	202,563	1,593,444
Cumulative effect adjustment for adoption of ASUs	—	—	—	174	—	174
Net income (loss)	—	—	—	(553,879)	51	(553,828)
Other comprehensive income (net of tax $(47))	—	—	481	—	—	481
Total comprehensive loss						(553,347)
Distribution to non-controlling interest	—	—	—	—	(918)	(918)
Activity in employee compensation plans	177	16,044	—	—	61	16,282
Balances, December 31, 2019	10,591	644,152	—	199,135	201,757	1,055,635
Net income (loss)	—	—	—	(931,012)	40,388	(890,624)
Activity in employee 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 employee compensation plans	—	39	—	—	19	58
Balances, December 31, 2020 (Successor)	$ 120	$ 197,242	$ —	$ (18,140)	$ 246,371	$ 425,593

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
OPERATING ACTIVITIES:			
Net loss	$ (13,988)	$ (890,624)	$ (553,828)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, and amortization	27,962	115,496	275,573
Impairments (Note 4)	26,063	867,814	625,716
Loss on abandonment of assets (Note 4)	—	18,733	—
Amortization of debt issuance costs and debt discount (Note 9)	—	1,079	2,241
(Gain) loss on derivatives (Note 15)	985	10,704	(4,225)
Cash receipts (payments) on derivatives settled (Note 15)	(1,133)	(4,244)	16,196
(Gain) loss on disposition of assets	(619)	(89)	3,502
Write-off of debt issuance costs	—	2,426	—
Deferred tax benefit (Note 11)	—	(13,713)	(131,045)
Employee stock compensation plans	58	4,786	12,932
Bad debt expense	—	3,155	527
ARO liability accretion (Note 10)	467	1,545	2,343
Contract assets and liabilities, net (Note 5)	1,316	2,459	(2,577)
Noncash reorganization items	67	(138,797)	—
Other, net	(3,046)	12,164	1,766
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(7,226)	28,880	33,323
Materials and supplies	—	89	24
Prepaid expenses and other	1,795	(3,849)	195
Accounts payable	1,484	(18,381)	(15,558)
Accrued liabilities	(4,048)	44,811	3,142
Income taxes	(301)	906	298
Contract advances	(29)	(394)	(1,149)
Net cash provided by operating activities	29,807	44,956	269,396
INVESTING ACTIVITIES:			
Capital expenditures	(4,057)	(25,775)	(406,665)
Producing property and other oil and natural gas acquisitions	—	(382)	(3,653)
Other acquisitions	—	—	(16,109)
Proceeds from disposition of property and equipment	1,799	6,018	31,864
Net cash used in investing activities	(2,258)	(20,139)	(394,563)

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

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	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
FINANCING ACTIVITIES:			
Borrowings under line of credit, including borrowings under DIP credit facility	$ —	$ 87,400	$ 493,500
Payments under line of credit	(49,000)	(64,100)	(368,800)
DIP financing costs	—	(990)	—
Exit facility financing costs	—	(3,225)	—
Net payments on finance leases	(1,406)	(2,757)	(4,001)
Proceeds from investments in non-controlling interest	—	—	—
Employee taxes paid by withholding shares	—	(43)	(4,158)
Transaction costs associated with sale of non-controlling interest	—	—	—
Distributions to non-controlling interest	—	—	(918)
Bank overdrafts (Note 4)	2,631	(8,733)	3,663
Net cash provided by (used in) financing activities	(47,775)	7,552	119,286
Net increase (decrease) in cash, restricted cash, and cash equivalents	(20,226)	32,369	(5,881)
Cash, restricted cash, and cash equivalents, beginning of period	32,940	571	6,452
Cash, restricted cash, and cash equivalents, end of period	$ 12,714	$ 32,940	$ 571
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$ 2,571	$ 6,417	$ 33,694
Income taxes	$ —	$ —	$ 273
Reorganization items	$ 2,206	$ 4,822	$ —
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	$ 1,902	$ 8,561	$ 54,549
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	$ 1,702	$ 29,189	$ (76)
Non-cash trade of property, plant, and equipment	$ —	$ 1,403	$ —

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

NOTE 1 – ORGANIZATION

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, North Dakota, and to a lesser extent in Colorado.

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 – 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 participations 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.

On December 11, 2020, approximately 10.5 million shares of New Common Stock were distributed to the holders of the Notes entitled to receive their 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. The remaining 0.9 million shares are being held for the Disputed Claims Reserve.

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 company's Old Common Stock outstanding before the Effective Date that did not opt out of the release under the Plan, may receive its pro rata share of seven-year warrants (Warrants) to purchase an aggregate of 12.5% of the shares of New Common Stock, at an aggregate exercise price equal to the $650.0 million principal amount of the Notes plus interest thereon to the May 15, 2021 maturity date of the Notes. On the Effective Date, the company entered into a Warrant Agreement (Warrant Agreement) with American Stock Transfer & Trust Company, LLC. The Warrants will expire on the earliest of (i) September 3, 2027, (ii) the 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 not exercised by the Expiration Date will expire, and all rights under that Warrant and the Warrant Agreement will cease on the Expiration Date. On December 21, 2020, the company issued approximately 1.8 million Warrants to the holders of the Old Common Stock that did not opt out of the releases under the Plan and owned their shares of Old Common Stock in street name through the facilities of the DTC. On February 11, 2021, we issued approximately 43,000 Warrants to certain holders of the Old Common Stock that did not opt out of the releases under the Plan and owned their shares through direct registration with the company's transfer agent (Direct Registration). The company expects to issue approximately 37,000 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. Under the Plan, additional Warrants will be issued in book-entry form through the facilities of the DTC, and each holder owning shares of Old Common Stock through Direct Registration must provide that holder's brokerage account information to the company to receive such holder's distribution of Warrants. Any distribution not made will be deemed forfeited at the first anniversary of the Effective Date.

Events of Default

The filing of the Chapter 11 Cases constituted an event of default that accelerated the company's obligations under the Unit credit agreement and the indenture governing the Notes. Additionally, other events of default, including cross-defaults, existed, or occurred under these debt agreements. The amounts owed regarding the Notes were classified as liabilities subject to compromise. 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, Unit Credit Facility, and Debtor-in-Possession Credit Agreement

To provide liquidity to fund our operations and the Chapter 11 Cases, 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).

Going Concern

At June 30, 2020, the significant risks and uncertainties related to the company's liquidity and Chapter 11 Cases raised substantial doubt about the company's ability to continue as a going concern. The company, therefore, concluded as of that date there was substantial doubt about the company's ability to continue as a going concern. The company implemented changes that (i) minimized capital expenditures, (ii) aggressively managed its working capital, and (iii) reduced recurring operating expenses. As a result of those changes and the successful reorganization of our long term debt, we determined that there is no longer substantial doubt about the company's ability to continue operating as a going concern for a period of at least one year.

Exit Credit Agreement

On the Effective Date, under the Plan, we entered into an amended and restated credit agreement (Exit Credit Agreement). Refer to Note 9 – Long-Term Debt and Other Long-Term Liabilities for the terms of the Exit Credit Agreement.

Interest Expense

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 – 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. Refer to Note 2 – Emergence From Voluntary Reorganization Under Chapter 11 for the terms of the Plan.

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 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 (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 (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, 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 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, 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.

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of September 1, 2020						
ASSETS	Predecessor	Reorganization Adjustments [(1)]		Fresh Start Adjustments [(11)]		Successor
	(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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	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 described in Note 2 – Emergence From Voluntary Reorganization Under Chapter 11 (in thousands):

Funding of the professional fees escrow account	$	(7,458)
Proceeds from Exit credit facility		8,000
Payment of debt issuance costs on the Exit credit facility		(3,225)
Payment of professional fees		(3,943)
Payment 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):

Liabilities 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
Total liabilities subject to compromise		762,215
Separation settlement treatment		(6,905)
Successor Common Stock and APIC[(1)] issued to allowed claim holders		(175,521)
Successor Common Stock and APIC for disputed claims reserve		(11,936)
Gain 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	Predecessor
	Fair Value	**Historical Book Value**
	(In thousands)	
Proved properties	$ 238,284	$ 6,539,816
Unproved properties	—	30,205
	238,284	6,570,021
Less 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	Predecessor
	Fair Value	**Historical Book Value**
	(In thousands)	
Drilling equipment	$ 63,458	$ 1,285,024
Gas gathering and processing equipment	250,098	833,788
Saltwater disposal systems	—	43,541
Land and building	32,635	59,080
Transportation equipment	3,314	15,577
Other	9,958	57,427
	359,463	2,294,437
Less 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 below in Note 4 – Summary Of Significant Accounting Policies, our Consolidated Statements of Operations for the periods ended August 31, 2020 and December 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
	Four Months Ended	Eight Months Ended
	December 31, 2020	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	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	$ 2,273	$ (133,975)

NOTE 4 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. We consolidate 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 (GAAP). 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 19 – Variable Interest Entity Arrangements.

Effective at emergence, we record our share of earnings and losses from Superior using the HLBV method of accounting. The HLBV is a balance-sheet approach that calculates the amount we would have received if Superior were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our Consolidated Statements of Operations. On the sale or liquidation of Superior, distributions would occur in the order and priority specified in the relevant agreements.

Fresh Start Accounting. The consolidated financial statements in Note 3 - 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. To facilitate the financial statement presentations, 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. Furthermore, 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.

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, or the Predecessor Period. That guidance requires, for periods after our bankruptcy filing on May 22, 2020, or post-petition periods, certain transactions and events that were directly related to our reorganization be distinguished from our normal business operations. 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. In addition, certain liabilities and other obligations incurred before May 22, 2020, or pre-petition periods, have been classified as "Liabilities subject to compromise" on our Predecessor Consolidated Balance Sheets through August 31, 2020. See Note 3 – Fresh Start Accounting for further detail.

Accounting Estimates. Preparing financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Drilling Contracts. Because we not do bear the risk of completion of the well, we recognize revenues and expenses generated from "daywork" drilling contracts as the services are performed. Typically, this type of contract can be used for the drilling of one well which can take from 10 to 90 days. At December 31, 2020, all our contracts were daywork contracts of which five were multi-well and had durations which ranged from two months to one year, three of which expire in 2021 and two expiring in 2022. These longer-term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Cash Equivalents and Bank Overdrafts. We include as cash equivalents all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. 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. At December 31, 2020 and 2019, bank overdrafts were $2.6 million and $8.7 million, respectively.

Accounts Receivable. Accounts receivable is carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We estimate the allowance for doubtful accounts 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 doubtful accounts only after all collection attempts have been unsuccessful.

Financial Instruments and Concentrations of Credit Risk and Non-performance Risk. Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade receivables with a variety of oil and natural gas companies. We do not generally require collateral related to our receivables. Our credit risk is considered limited due to the many customers comprising our customer base. Below are the third-party customers that accounted for over 10% of each of our segment's revenues:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
Oil and Natural Gas:			
CVR Refining, LP	14 %	15 %	14 %
Plains Marketing L.P.	*	11 %	*
Drilling:			
EOG Resources, Inc.	28 %	20 %	12 %
QEP Resources, Inc.	23 %	10 %	12 %
Citizen Energy III, LLC	16 %	*	*
Slawson Exploration Company, Inc.	16 %	21 %	11 %
Cimarex Energy Co.	12 %	*	*
Mid-Stream:			
ONEOK, Inc.	28 %	31 %	33 %
Range Resources Corporation	15 %	21 %	13 %
Centerpoint Energy Service, Inc.	*	*	10 %

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

We had a concentration of cash of $21.4 million and $1.7 million at December 31, 2020 and 2019, respectively with one bank.

Using derivative transactions also 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, 2020 and determined there was no material risk at that time. At December 31, 2020, the fair values of the net liabilities we had with each of the counterparties regarding our commodity derivative transactions are listed in the table below:

	December 31, 2020
	(In millions)
Bank of Oklahoma	$ (5.4)
Bank of Montreal	(0.3)
Total net liabilities	$ (5.7)

Property and Equipment. Drilling equipment, transportation equipment, gas gathering and processing systems, 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, we elected to depreciate all drilling assets utilizing the straight-line method over the useful lives of the assets ranging from four to ten years. Depreciation on our corporate building is computed using the straight-line method over the estimated useful life of the asset for 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 3 to 15 years.

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.

At March 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 the first quarter of 2020. We also recorded an additional non-cash impairment charge of $3.0 million for other miscellaneous drilling equipment. These charges are included within impairment charge in our Consolidated Statements of Operations.

We used the income approach to determine the fair value of the SCR drilling rigs asset group. This approach uses significant assumptions including management's best estimates of the expected future cash flows and the estimated useful life of the asset group. Fair value determination requires a considerable amount of judgement and is sensitive to changes in underlying assumptions and economic factors. As a result, there is no assurance the fair value estimates made for the impairment analysis will be accurate in the future.

We concluded that no impairment was needed on the BOSS drilling rigs asset group as the undiscounted cash flows exceeded the carrying value of the asset group. The carrying value of the asset group was approximately $242.5 million at March 31, 2020. The estimated undiscounted cash flows of the BOSS drilling rigs asset group exceeded the carrying value by a relatively minor margin, which means minor changes in certain key assumptions in future periods may result in material impairment charges in future periods. Some of the more sensitive assumptions used in evaluating the contract drilling rigs asset groups for potential impairment include forecasted utilization, gross margins, salvage values, discount rates, and terminal values.

We recorded expense of $1.1 million related to the write-down of certain equipment in the third quarter of 2020 that we now consider abandoned. These amounts are reported in loss on abandonment of assets in our Consolidated Statements of Operations.

During the third quarter of 2019, we determined a triggering event had occurred within our contract drilling segment due to a decline in the number of drilling rigs being used and the overall market performance of the contract drilling industry. As a result, we performed a recoverability test on long-lived assets within that segment. Based on the results of the undiscounted future cash flows of that asset group, the undiscounted projected future cash flows of the asset group exceeded the group's carrying value as of September 30, 2019 and therefore no long-lived asset impairment was recorded for the group.

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.

For our gas gathering and processing systems, 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. Based on the estimated fair value of the asset groups, we recorded non-cash impairment charges of $64.0 million. These charges are included within impairment charges in our Consolidated Statement of Operations.

Capitalized Interest. During 2019, interest of approximately $16.2 million was capitalized based on the net book value associated with unproved oil and gas properties not being amortized, constructing additional drilling rigs, and constructing gas gathering systems. Interest is being capitalized using a weighted average interest rate based on our outstanding borrowings. We did not capitalize any interest in 2020.

Goodwill. Goodwill represents the excess of the cost of an acquisition over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed annually to determine whether the fair value has decreased or additionally when events indicate an impairment may have occurred. For impairment testing, goodwill is evaluated at the reporting unit level. Our goodwill is all related to our contract drilling segment, and, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, using discount rates and other factors in determining the fair value of our drilling segment. Inputs in our estimated discounted future net cash flows include drilling rig utilization, day rates, gross margin percentages, and terminal value. Due to the triggering event within the contract drilling segment, we performed an interim goodwill impairment test as of September 30, 2019. Based on the projected discounted cash flows, we recognized a goodwill impairment charge of $62.8 million, pre-tax ($59.8 million, net of tax) which represented total goodwill we previously reported on our Consolidated Balance Sheets. There were no additions to goodwill in 2020 or 2019.

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. 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. Directly related overhead costs of $16.5 million were capitalized in 2019. We did not capitalize any directly related overhead costs in 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 $4.21, $7.77, and $9.66 per Boe in the Successor Period of 2020, the Predecessor Period of 2020, and for the year 2019, respectively.

During the fourth quarter 2019, we reassessed estimated salvage values associated with our oil and natural gas operations. Based on market conditions for our industry and the substantial doubt that existed for our ability to continue as a going concern, we revised these estimates downward for a total adjustment of $39.7 million ($25.6 million discounted for our full cost ceiling test) to salvage value estimates.

No gains or losses are recognized on the sale, conveyance, or other disposition of oil and natural gas properties unless a significant reserve amount to our total reserves is involved. Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

Successor Period Impairments. As of September 1, 2020, we adopted fresh start accounting and adjusted our assets to fair value. Although under fresh start accounting we recorded our assets at fair value on emergence, the application of the full cost accounting rules resulted in non-cash ceiling test write-downs of $26.1 million pre-tax for Successor Period primarily due to the use of average 12-month historical commodity prices for the ceiling test versus forward prices for our Fresh Start fair value estimates.

It is hard to predict with any certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at December 31, 2020, and only adjust the 12-month average price as of March 2021, our forward-looking expectation is that we will not recognize an impairment in the first quarter of 2021. Given the uncertainty associated with the factors used in calculating our estimate of our future period ceiling test write-down, these estimates should not necessarily be construed as indicative of our future plans or financial results and the actual amount of any write-down may vary significantly from this estimate depending on the final future determination.

Predecessor Period Impairments. We determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. Those determinations resulted in $226.5 million and $73.9 million in 2020 and 2019, respectively, of costs being added to the total of our capitalized costs being amortized. We recorded non-cash ceiling test write-downs of $393.7 million pre-tax ($346.6 million, net of tax) in the Predecessor Period of 2020 due to the reduction for the 12-month average commodity prices and the impairment of our unproved oil and gas properties described above. We incurred non-cash ceiling test write-downs of $559.4 million pre-tax ($422.4 million, net of tax) in 2019.

In addition to the impairment evaluations of our proved and unproved oil and gas properties in the first quarter of 2020, we also evaluated the carrying value of our salt water disposal assets. Based on our revised forecast of the use of those assets, we determined that some of those assets were no longer expected to be used and we wrote off those salt water disposal assets that we now consider abandoned. We recorded total expense of $17.6 million related to the write-down of those salt water disposal assets for the eight months ended August 31, 2020. These amounts are reported in loss on abandonment of assets in our Consolidated Statements of Operations.

Our contract drilling segment provides drilling services for our oil and natural gas segment. 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. The contracts for these services are issued under the similar terms and rates as the contracts entered into with unrelated third parties. By providing drilling services for the oil and natural gas segment, we eliminated $1.6 million of intercompany profit during 2019 as a reduction to the carrying value of our oil and natural gas properties. We did not eliminate any profit in 2020 due to no drilling services being provided during the period.

ARO. We record the fair value of liabilities associated with the future plugging and abandonment of our wells. When the reserves in each of our oil or gas wells becoming fully depleted or otherwise become uneconomical, we incur costs to plug and abandon the wells. These future costs are recorded at the time the wells are drilled or acquired. We have no assets restricted to settle these ARO liabilities. Our engineering staff uses historical experience to determine the estimated plugging costs considering the type of well (either oil or natural gas), the depth of the well, the physical location of the well, and the ultimate productive life to determine the estimated plugging costs. A risk-adjusted discount rate and an inflation factor are used on these estimated costs to determine the present value of this obligation. To the extent any change in these assumptions affect future revisions and impact the present value of the existing ARO, a corresponding adjustment is made to the full cost pool.

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

Derivative Activities. All derivatives are recognized on the balance sheet and measured at fair value. Any changes in our derivatives' fair value before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Consolidated Statements of Operations. Cash settlements received or paid for matured, early-terminated, and modified derivatives are reported in cash receipts (payments) on derivatives settled in our Consolidated Statements of Cash Flows.

We do not engage in derivative transactions solely for speculative purposes.

Limited Partnerships. Unit Petroleum Company was a general partner in 13 oil and natural gas limited partnerships. Some of our officers, directors, and employees owned the interests in most of these partnerships. We shared in each partnership's revenues and costs under formulas set out in the limited partnership agreement. The partnerships also reimbursed us for certain administrative costs incurred on behalf of the partnerships. The partnerships were terminated in the second quarter of 2019 with an effective date of January 1, 2019 at a repurchase cost of $0.6 million, net of Unit's interest.

Income Taxes. Measurement of net deferred tax liabilities is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where needed to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

The accounting for uncertainty in income taxes prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

Natural Gas Balancing. We account for revenue transactions under ASC 606 for recording natural gas sales, which may be more or less than our share of pro-rata production from certain wells. We estimate our December 31, 2020 balancing position to be approximately 3.3 Bcf on under-produced properties and approximately 3.3 Bcf on over-produced properties. We have recorded a receivable of $3.4 million on certain wells where we estimate that insufficient reserves are available for us to recover our under-production from future production volumes. We have also recorded a liability of $4.0 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. 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.

Employee and Director Stock Based Compensation. We recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. Our equity compensation cost relating to employees directly involved in exploration activities of our oil and natural gas segment is capitalized to our oil and natural gas properties. Amounts not capitalized to our oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We used the Black-Scholes option pricing model to measure the fair value of stock options and SARs. The value of our restricted stock grants was based on the closing stock price on the date of the grants. On the Effective Date, all unvested restricted stock and un-exercised stock options were cancelled. The cancellation of the awards resulted in an acceleration of unrecorded stock compensation expense during the Predecessor Period. See Note 14 – Stock-Based Compensation for further detail.

New Accounting Standards

Reference Rate Reform (Topic 848)—Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The FASB issued ASU 2020-04 which provides 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 ASU is intended to help stakeholders during the global market-wide reference rate transition period. The amendments within this ASU 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. The amendments will not have a material impact on our consolidated financial statements.

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 amendments will be effective for reporting periods beginning after December 15, 2020. Early adoption is permitted. This standard will not have a material impact on our consolidated financial statements.

Adopted Standards

Measurement of Credit Losses on Financial Instruments (Topic 326). The FASB issued ASU 2016-13 which replaces current methods for evaluating impairment of financial instruments not measured at fair value, including trade accounts receivable, and certain debt securities, with a current expected credit loss model (CECL). The CECL model is expected to result in more timely recognition of credit losses. The amendment was effective for reporting periods after December 15, 2019. The adoption of this guidance did not have a material impact on our consolidated financial statements or related disclosures.

Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement. The FASB issued ASU 2018-13 to modify the disclosure requirements in Topic 820. Part of the disclosures were removed or modified, and other disclosures were added. The amendment was effective for reporting periods beginning after December 15, 2019. The adoption of this guidance did not have a material impact on our consolidated financial statements or related disclosures.

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 20 – 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 sell the hydrocarbons (from the oil and natural gas and mid-stream segments) to other mid-stream and downstream oil and gas companies.

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 Contracts, Revenues, Implementation Impact to Retained Earnings, and Performance Obligations

Typical types of revenue contracts signed by our oil and gas segments 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 our Joint Operating Agreements. Contract terms can range from a single month to a term spanning a decade or more; some may also include evergreen provisions. Revenues from our sales are recognized when our customer obtains control of the sold product. For sales we make to other mid-stream and downstream oil and gas companies, control typically occurs at a point on delivery to the customer. Sales generated from our non-operated interest are recorded based on the information obtained from the operator. Our adoption of this standard required no adjustment to opening retained earnings.

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.

Our performance obligation for all commodity contracts is the delivery of oil and gas volumes to the customer. Typically, the contract is for a specified period (for example, a month or a year); however, each delivery under that contract can be considered as separately identifiable since each delivery provides its own benefits to the customer. For feasibility, as accounting for a monthly performance obligation is not materially different than identifying a more granular performance obligation, we conclude this performance obligation is satisfied monthly. We typically receive a payment within a set number of days following the end of the month of performance which includes payment for all deliveries in that month. Subject to any contract terms, judgment could be required to determine when the transfer of control occurs. Generally, depending on the facts and circumstances, we consider the change of control of the asset in a commodity sale to occur at the point the commodity transfers to the customer.

The consideration we receive for oil and gas sales is variable. Most of our contracts state the consideration is calculated by multiplying a variable quantity by a variable price less deductions related to any allowed gathering, transportation, fractionation, and related fuel charges. All variable consideration is settled at the end of the month; therefore, the variability does not affect accounting for revenue under ASC 606 as the variability is known before each reporting period. An estimation and allocation of transaction price and future obligations are not required.

Contract Drilling Contracts, Revenues, Implementation impact to retained earnings, and Performance Obligations

The contract drilling segment uses contracts with terms ranging from two months to three or more years or that can be based on terms to drill a specific number of wells. The allocation rules in ASC 606 (called the "series guidance") provide that a contract may contain a single performance obligation composed of a series of distinct goods or services if 1) each distinct good or service is substantially the same and would meet the criteria to be a performance obligation satisfied over time and 2) each distinct good or service is measured using the same method as it relates to the satisfaction of the overall performance obligation. We have determined that the delivery of drilling services is within the scope of the series guidance as both criteria noted above are met. Specifically, 1) each distinct increment of service (i.e., hour available to drill) that the drilling contractor promises to transfer represents a performance obligation that would meet the criteria for recognizing revenue over time, and 2) the drilling contractor would use the same method for measuring progress toward satisfaction of the performance obligation for each distinct increment of service in the series. At inception, the total transaction price is estimated to include any applicable fixed consideration, unconstrained variable consideration (estimated day rate mobilization and demobilization revenue, estimated operating day rate revenue to be earned over the contract term, expected bonuses (if material and can be reasonably estimated without significant reversal)), and penalties (if material and can be reasonably estimated without significant reversal). The estimation of the transaction price for unconstrained variable consideration does not differ materially from the previous revenue accounting standard. A contract liability will be recorded for consideration received before the corresponding transfer of services. Those liabilities will generally only arise in relation to upfront mobilization fees paid in advance and are allocated/recognized over the entire performance obligation. Such balances if material will be amortized over the recognition period based on the same method of measure used for revenue.

Our performance obligation for all drilling contracts is to drill the agreed-on number of wells or drill over an agreed-on period as stated in the contract. Any mobilization and demobilization activities are not considered distinct within the context of the contract and therefore, any associated revenue is allocated to the overall performance obligation of drilling services and recognized ratably over the initial term of the related drilling contract. It typically takes from 10 to 90 days to complete drilling a well; therefore, depending on the number of wells under a contract, the contract term could be up to three years. Most of the drilling contracts are for less than one year. As the customer simultaneously receives and consumes the benefits provided by the company's performance, and the company's performance enhances an asset that the customer controls, the performance obligation to drill the well occurs over time. We typically receive payment within a set number of days following the end of the month and that payment includes payment for all services performed during that month (calculated on an hourly basis). The company satisfies its overall performance obligation when the well included in the contract is drilled to an agreed-on depth or by a set date.

All consideration received for contract drilling is variable, excluding termination fees. The consideration is calculated by multiplying a variable quantity (number of days/hours) by an agreed-on daily price (for the daily rate, mobilization, and demobilization revenue). Other revenue items under the contract may include bonus/penalty revenue, reimbursable revenue, drilling fluid rates, and early termination fees. All variable consideration is not constrained but is settled at the end of the month; therefore, whether the variability is constrained or not does not affect accounting for revenue under ASC 606 as the variability is known before each reporting period excluding certain bonuses/penalties which might be based on activity that occurs over the entire term of the contract. We have evaluated the mobilization and de-mobilization charges on outstanding contracts, however, the impact to the financial statements was immaterial. As of December 31, 2020, we had nine drilling contracts (five of which are term contracts) for a duration of two months to one year.

Under the guidance in relation to disclosures regarding the remaining performance obligations, there is a practical expedient for contracts with an original expected duration of one year or less (ASC 606-10-50-14) and for contracts where the entity can recognize revenue as invoiced (ASC 606-10-55-18). Most of our drilling contracts have an original term of less than one year; however, the remaining performance obligations under the contracts with a longer duration are not material.

Mid-stream Contracts Revenues, and Implementation impact to retained earnings, and Performance Obligations

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. Our gas gathering and processing revenues are generally variable because the volumes are dependent on throughput by third-party customers for which the service provided is only specified on a daily or monthly basis. We deliver natural gas, NGLs and condensate to purchasers at contractually agreed-upon delivery points at which the purchaser takes custody, title, and risk of loss of the commodity. We recognize revenue at the point in time when control transfers to the purchaser at the 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 represent an arrangement where a customer agrees to pay a fixed fee for a contractually agreed upon pipeline capacity, which results in performance obligations for each individual period of reservation. Once the services have been completed, or the customer no longer has access to the contracted capacity, revenue is recognized.

Before implementing ASC 606, we immediately recognized the entire demand fee since the fee was payable within the first five years from the effective date of the contract and not over the entire term of the contract. However, the demand fee is a stand-ready obligation under ASC 606 and is now to be recognized over the life of the contract. Therefore, the demand fee previously recognized for $1.7 million ($1.3 million, net of tax) was adjusted to retained earnings as of January 1, 2018 and is recognized over the remaining term of the contract.

Included below is the adjustment to demand fees from adopting ASC 606 over the remaining term of the contracts as of December 31, 2020.

Contract	Remaining Term of Contract	2021	2022	2023 and beyond	Total Remaining Impact to Revenue
Demand fee contracts	2-8 years	$ (3,501)	$ 1,380	$ 36	$ (2,085)

The adjustment to revenue for these demand fees was $(3.8) million and $2.6 million in 2020 and 2019, respectively.

	Classification on the Consolidated Balance Sheets	Successor December 31, 2020	Predecessor December 31, 2019	Change
			(In thousands)	
Assets				
Current contract assets	Prepaid expenses and other	$ 6,084	$ 6,664	$ (580)
Non-current contract assets	Other assets	173	6,257	(6,084)
Total contract assets		$ 6,257	$ 12,921	$ (6,664)
Liabilities				
Current contract liabilities	Current portion of other long-term liabilities	$ 2,583	$ 2,889	$ (306)
Non-current contract liabilities	Other long-term liabilities	1,589	4,172	(2,583)
Total contract liabilities		4,172	7,061	(2,889)
Contract assets (liabilities), net		$ 2,085	$ 5,860	$ (3,775)

Shortfall fees are minimum volume commitment arrangements where a customer agrees to pay the contractually agreed upon gathering fees for a minimum volume of natural gas irrespective of whether or not the minimum volume of natural gas is delivered, which results in performance obligations for each individual unit of volume. If the actual volumes exceed the minimum volume of natural gas, the customer pays the contractually agreed upon gathering fees for the excess volumes in addition to the fees paid for the minimum volume of natural gas. Once the services have been completed, or the customer no longer has the ability to utilize the services, the performance obligation is met, and revenue is recognized. In addition, when certain minimum volume commitment fee arrangements include commitments of one year or more, significant judgment is used in interim commitment periods in which a customer's actual volumes are deficient in relation to the minimum volume commitment. Revenue is recognized when the likelihood of the customer meeting the minimum volume commitment becomes remote. During the Successor Period and Predecessor Period of 2020, we recognized revenue from shortfall fees of $4.0 million and $1.3 million, respectively. No shortfall fees were recognized in the year 2019.

NOTE 6 – ACQUISITIONS AND DIVESTITURES

Acquisitions

Oil and Natural Gas

During the Successor Period of 2020, there was no significant acquisition activity. During the Predecessor Period of 2020, we had $0.4 million in acquisitions, while for 2019, we had approximately $3.7 million in acquisitions.

Mid-Stream

There was no significant acquisition activity in 2020.

In December 2019, we closed on an acquisition for $16.1 million that included approximately 572 miles of pipeline and related compressor stations. The transaction closed on December 30, 2019 with an effective date of December 01, 2019 and was accounted for as an asset acquisition.

Divestitures

Oil and Natural Gas

We had non-core asset sales with proceeds, net of related expenses, of $0.4 million, $1.2 million and $21.8 million in the Successor Period and Predecessor Period of 2020 and the year 2019, respectively. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

Contract Drilling

During 2019, we sold six of the drilling rigs and other equipment to unaffiliated third parties. The proceeds of those sales, less costs to sell, was more than the $5.7 million net book value resulting in a gain of $1.1 million. Seven drilling rigs and equipment remained classified as assets held for sale and were to be marketed for sale throughout the next twelve months. The net book value of those assets was $5.9 million.

During the first quarter of 2020, due to market conditions, it was determined those assets would not be sold in the next twelve months and were reclassified to long-lived assets. As of December 31, 2020, we have no assets that meet the criteria to be classified as held for sale. We do have plans to sell drilling rigs but they have zero net book value after fresh start so they are not reported as assets held for sale.

NOTE 7 – LOSS PER SHARE

Successor Period

On the Effective Date, the company issued 12.0 million shares of New Common Stock at a par value of $0.01 per share that were to be subsequently distributed in accordance with the Plan.

Information related to the calculation of loss per share attributable to the company is:

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the four months ended December 31, 2020			
Basic loss attributable to Unit Corporation per common share	$ (18,140)	12,000	$ (1.51)

Predecessor Period

Information related to the calculation of loss per share attributable to the company is:

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2019:			
Basic loss attributable to Unit Corporation per common share	$ (553,879)	52,849	$ (10.48)
Effect of dilutive stock options and restricted stock	—	—	—
Diluted loss attributable to Unit Corporation per common share	$ (553,879)	52,849	$ (10.48)
For the eight months ended August 31, 2020			
Basic loss attributable to Unit Corporation per common share	$ (931,012)	53,368	$ (17.45)

The following options were not included in the weighted shares above as their affect would be anti-dilutive to the computation of loss per share for the year ended December 31:

	2019
Stock options	42,000
Average exercise price	$ 48.56

NOTE 8 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31:

	Successor 2020	Predecessor 2019
	(In thousands)	
Employee costs	$ 8,878	$ 17,832
Lease operating expenses	6,405	9,200
Taxes	2,324	3,450
Legal settlement (Note 18)	2,070	—
Interest payable	884	6,562
Third-party credits	—	3,691
Other	1,182	5,827
Total accrued liabilities	$ 21,743	$ 46,562

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

Long-Term Debt

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

	Successor 2020	Predecessor 2019
	(In thousands)	
Current portion of long-term debt:		
Predecessor credit facility with an average interest rate of 4.0%	$ —	$ 108,200
Successor Exit Facility with an average interest rate of 6.6%	600	—
Long-term debt:		
Successor Exit Facility with an average interest of 6.6%	98,400	—
Superior credit agreement with an average interest rate of 3.9% at December 31, 2019	—	16,500
Predecessor 6.625% senior subordinated notes due 2021	—	650,000
Total principal amount	$ 98,400	$ 666,500
Less: unamortized discount	—	(971)
Less: debt issuance costs, net	—	(2,313)
Total long-term debt	$ 98,400	$ 663,216

Successor Exit Credit Agreement. On the Effective Date, under the Plan, we entered into the Exit Credit Agreement, providing for a $140.0 million senior secured revolving credit facility and a $40.0 million senior secured term loan facility, among (i) the company, UDC, and UPC, (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, and (iv) BOKF, NA dba Bank of Oklahoma as administrative agent and collateral agent (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.

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 ending (i) December 31, 2020 and March 31, 2021, to be greater than 4.00 to 1.00, (ii) June 30, 2021, September 30, 2021, December 31, 2021, March 31, 2022, and June 30, 2022, to be greater than 3.75 to 1.00, and (iii) September 30, 2022 and any fiscal quarter thereafter, to be greater than 3.50 to 1.00. In addition, beginning with the fiscal quarter ending 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 0.50 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, restrict certain asset sales and the related use of proceeds, and require certain hedging activities. The Exit Credit Agreement further requires that we provide quarterly financial statements within 45 days after the end of each of the first three quarters of each fiscal year and annual financial statements within 90 days after the end of each fiscal year. As of December 31, 2020, we were in compliance with these covenants.

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 our ownership interests in Superior Pipeline Company, L.L.C.

On the Effective Date, we had (i) $40.0 million in principal amount of Term Loans outstanding, (ii) $92.0 million in principal amount of Revolving Loans outstanding, and (iii) approximately $6.7 million of outstanding letters of credit. At December 31, 2020, we had $0.6 million and $98.4 million outstanding current and long-term borrowings, respectively, under the Exit Credit Agreement.

Predecessor's Credit Agreement. Before the filing of the Chapter 11 Cases, the 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). The Debtors' filing of the Chapter 11 Cases constituted an event of default that accelerated the Debtors' obligations under the Unit credit agreement and the indenture governing the Notes. Due to the Credit Agreement Extension Condition, our debt associated with the Unit credit agreement is reflected as a current liability in our Consolidated Balance Sheets as of December 31, 2019. The classification as a current liability due to the Credit Agreement Extension Condition was based on the uncertainty regarding our ability to repay or refinance the Notes before November 16, 2020. In addition, on May 22, 2020, the lenders' remaining commitments under the Unit credit agreement were terminated.

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 second quarter of 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 Predecessor 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.

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.

On the Effective Date, each lender under the Unit credit agreement and 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 exchange for that lender's allowed claims under the 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. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio 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. As of December 31, 2020, Superior was in compliance with these covenants.

Borrowings under the Superior credit agreement will fund capital expenditures and acquisitions, provide general working capital, and for letters of credit for Superior.

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 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 Notes.

As a result of Unit's emergence from bankruptcy, the Notes were cancelled and our liability under the Notes was discharged as of the Effective Date. Holders of the 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 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 the $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. On the Effective Date, 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 – Emergence From Voluntary Reorganization Under Chapter 11.

Other Long-Term Liabilities

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

	Successor	Predecessor
	2020	2019
	(In thousands)	
ARO liability	$ 23,356	$ 66,627
Workers' compensation	10,164	11,510
Separation benefit plans [1]	4,201	10,122
Contract liability	4,172	7,061
Gas balancing liability	3,997	3,838
Finance lease obligations	3,216	7,379
Other long-term liability	1,321	—
Deferred compensation plan	—	6,180
	50,427	112,717
Less current portion	11,168	17,376
Total other long-term liabilities	$ 39,259	$ 95,341

1. 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 allow 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. In accordance with the Plan, the New Separation Benefit Plan is 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 provides that eligible employees will be entitled to two weeks of severance pay per year of service, with a minimum of four weeks and a maximum of 13 weeks of severance pay.

NOTE 10 – 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 (AROs). 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 plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All our AROs relate to plugging costs associated with our oil and gas wells.

The following table shows certain information about our estimated AROs for the periods indicated (in thousands):

ARO liability, 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)
ARO liability, August 31, 2020 (Predecessor)	38,984
Fresh start adjustments	(14,393)
ARO liability, August 31, 2020 (Successor)	24,591
Accretion of discount	467
Liability incurred	151
Liability settled	(95)
Liability sold	—
Revision of estimates [(1)]	(1,758)
ARO liability, December 31, 2020 (Successor)	23,356
Less current portion (Successor)	2,121
Total long-term ARO (Successor)	$ 21,235

1. Plugging liability estimates were revised in 2019 and 2020 for updates in the cost of services used to plug wells over the preceding year and estimated dates to be plugged.

NOTE 11 – INCOME TAXES

As previously stated, we filed for Chapter 11 Bankruptcy protection during the second quarter of 2020 and emerged from the cases in the third quarter of 2020. This event had a significant impact on income taxes during 2020. Under the Plan, the Company's pre-petition debt securities were extinguished and holders of those securities received their pro-rata share of New Common Stock. Holders of Old Common Stock that did not opt out of the release under the Plan received its pro-rata share of Warrants. Please refer to Note 2 – Emergence From Voluntary Reorganization Under Chapter 11 for more information.

As a result of the Plan, 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 $457.5 million and the tax basis of our assets were reduced by $48.8 million. Even though these tax attribute reductions are not effective until January 1, 2021, the first day of the tax year after emergence, they have been recognized and reflected as such in the tables below.

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) is as follows:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
Income tax benefit computed by applying the statutory rate	$ (3,001)	$ (190,103)	$ (144,092)
State income tax benefit, net of federal benefit	(500)	(31,684)	(21,733)
Deferred tax liability revaluation	—	—	—
Restricted stock shortfall	—	7,404	347
Non-controlling interest in Superior	(1,017)	7,504	(11)
Goodwill impairment	—	—	12,346
Valuation allowance	4,047	177,284	19,654
Reorganization adjustments	—	14,152	—
Statutory depletion and other	169	813	1,163
Income tax benefit	$ (302)	$ (14,630)	$ (132,326)

For the periods indicated, the total provision for income taxes consisted of the following:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)	
Current taxes:			
Federal	$ —	$ (917)	$ (918)
State	(302)	—	(363)
	(302)	(917)	(1,281)
Deferred taxes:			
Federal	—	(16,663)	(108,440)
State	—	2,950	(22,605)
	—	(13,713)	(131,045)
Total provision	$ (302)	$ (14,630)	$ (132,326)

Deferred tax assets and liabilities are comprised of the following at December 31:

	Successor 2020	Predecessor 2019
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 22,051	$ 31,822
Net operating loss carryforward	100,236	246,927
Depreciation, depletion, amortization, and impairment	80,947	—
Alternative minimum tax and research and development tax credit carryforward	1,738	2,656
	204,972	281,405
Deferred tax liability:		
Depreciation, depletion, amortization, and impairment	—	(226,034)
Investment in Superior	(3,987)	(49,430)
Net deferred tax asset (liability)	200,985	5,941
Valuation allowance	(200,985)	(19,654)
Non-current—deferred tax liability	$ —	$ (13,713)

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. To the extent a valuation allowance is established or is increased or decreased during a period, there is a corresponding expense or reduction of expense within the tax provision in the Consolidated Statements of Operations.

During the year ended December 31, 2019, in evaluating whether it was more likely than not that the company's deferred tax assets were realizable through future net income, we considered all available positive and negative evidence, including (i) our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition, (ii) our ability to recover net operating loss carryforward deferred tax assets in future years, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) future revenue and operating cost projections that indicate the company will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures and (vii) current market prices for oil, NGL and natural gas. Based on all the evidence available, we determined it was more likely than not that the deferred tax asset for net operating loss carryforwards were not fully realizable. As of December 31, 2019, a total valuation allowance of $19.7 million has been recorded. As of December 31, 2020, the valuation allowance had increased to $201.0 million to reflect a full valuation allowance against our net deferred tax assets due to the impacts of the Plan from our bankruptcy proceedings, fresh start accounting, and tax attribute reductions as prescribed by IRC Section 108.

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 2016 or state income tax examinations by state taxing authorities for years before 2015. At December 31, 2020, we had expected federal net operating loss carryforwards of approximately $409.1 million of which $223.0 million would expire from 2021 to 2037.

NOTE 12 – EMPLOYEE BENEFIT PLANS

Under our 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 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. We made discretionary contributions under the plan of 310,797 shares of common stock in 2019 for the plan year 2018. The 2019 plan year matching contribution was made in cash instead of shares of common stock. On the Effective Date, all the shares of old common stock under the 401(k) Employee Thrift Plan were cancelled and each holder that did not opt out of the release under the Plan was entitled to receive his or her pro rata share of the Warrants in accordance with the Plan.

Total 401(k) employer matching expense was $0.7 million, $1.4 million, and $5.2 million in the Successor Period of 2020, the Predecessor Period of 2020, and the year 2019, respectively.

We provided a salary deferral plan for our executives (Deferral Plan) 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. The liability recorded under the Deferral Plan at December 31, 2019 was $6.2 million. We recognized payroll expense and recorded a liability at the time of deferral. As of December 31, 2020, investments held in the Deferral Plan had been paid out to plan participants and the plan was terminated.

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 allow 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. In accordance with the Plan, the New Separation Benefit Plan is 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 provides eligible employees with two weeks of severance pay per year of service, with a minimum of four weeks and a maximum of 13 weeks of severance pay. These benefits vest after 20 years of service provided to the company. We recognized expense of $1.4 million. $18.1 million, and $3.8 million in the Successor Period of 2020, the Predecessor Period of 2020, and the year 2019, respectively, for benefits associated with anticipated payments from these separation plans.

NOTE 13 – TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company served as the general partner of 13 oil and gas limited partnerships (the employee partnerships) which were formed to allow certain of our qualified employees and our directors to participate in Unit Petroleum's oil and gas exploration and production operations. Employee partnerships were formed for each year beginning with 1984 and ending with 2011. The partnerships were terminated in the second quarter of 2019 with an effective date of January 1, 2019 at a repurchase cost of $0.6 million, net of Unit's interest.

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 approximately $0.2 million and $0.4 million during the Predecessor period ended August 31, 2020 and the year ended December 31, 2019, respectively.

NOTE 14 – STOCK-BASED COMPENSATION

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 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 of the reorganized company (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. The LTIP will be administered by the Board or a committee thereof.

No shares under the LTIP have been awarded since the Effective Date through December 31, 2020.

Also on the Effective Date, the company's equity-based awards outstanding immediately before the Effective Date were cancelled. The cancellation of the awards resulted in an acceleration of unrecorded stock compensation expense during the Predecessor Period. 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 – Emergence From Voluntary Reorganization Under Chapter 11.

For restricted stock awards, we had:

	Predecessor	
	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
	(In millions)	
Recognized stock compensation expense [1]	$ 6.1	$ 12.8
Capitalized stock compensation cost for our oil and natural gas properties	$ —	$ 2.4
Tax benefit on stock-based compensation	$ 1.5	$ 3.1

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, net.

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. There were 7,230,000 shares of the company's common stock authorized for issuance to eligible participants under the amended plan with 2.0 million shares being the maximum number of shares that could be issued as "incentive stock options." The amended plan was terminated under the Plan.

Restricted Stock

Activity pertaining to restricted stock awards granted 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 January 1, 2019 (Predecessor)	1,268,883	608,125	1,877,008	$ 19.70
Granted	927,173	500,256	1,427,429	16.09
Vested	(570,107)	(233,835)	(803,942)	15.56
Forfeited	(98,301)	(33,172)	(131,473)	19.36
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 January 1, 2019 (Predecessor)	107,045	$	17.07
Granted	72,784		12.09
Vested	(61,141)		15.49
Forfeited	—		—
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)	—	$	—

The time vested restricted stock awards granted were being recognized over a three-year vesting period. There also were performance vested restricted stock awards granted to certain executive officers. All of these awards were cancelled on the Effective Date. We recognized a reversal of expense previously recorded for the unvested awards of $2.2 million for these awards upon cancellation.

The fair value of the restricted stock granted in 2019 at the grant date was $22.6 million.

Non-Employee Directors' Stock Option Plan

Under the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan, on the first business day following each annual meeting of shareholders, each person who was then a member of our Board of Directors 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. These awards and the plan were cancelled on the Effective Date.

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares		Weighted Average Exercise Price
Nonvested at January 1, 2019 (Predecessor)	66,500	$	44.42
Granted	—		—
Exercised	—		—
Forfeited	(24,500)		37.31
Nonvested 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 15 – 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. For further details, see Note 9 – Long-Term Debt And Other Long-Term Liabilities. As of December 31, 2020, our 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. All derivatives are recognized on the balance sheet and measured at fair value. Any changes in our derivatives' fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Consolidated Statements of Operations.

At December 31, 2020, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'21 - Dec'21	Natural gas - basis swap	30,000 MMBtu/day	$(0.215)	NGPL TEXOK
Jan'21 - Oct'21	Natural gas - swap	50,000 MMBtu/day	$2.818	IF - NYMEX (HH)
Nov'21 - Dec'21	Natural gas - swap	45,000 MMBtu/day	$2.900	IF - NYMEX (HH)
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'21 - Dec'21	Crude oil - swap	3,000 Bbl/day	$44.65	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

The following tables present the fair values and locations of the derivative transactions recorded in our Consolidated Balance Sheets at December 31:

		Derivative Assets Fair Value	
		Successor	Predecessor
	Balance Sheet Location	2020	2019
		(In thousands)	
Commodity derivatives:			
Current	Current derivative assets	$ —	$ 633
Long-term	Non-current derivative assets	—	—
Total derivative assets		$ —	$ 633

	Balance Sheet Location	Derivative Liabilities Fair Value Successor 2020	Derivative Liabilities Fair Value Predecessor 2019
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liabilities	$ 1,047	$ —
Long-term	Non-current derivative liabilities	4,659	27
Total derivative liabilities		$ 5,706	$ 27

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Consolidated Balance Sheets.

The following is the Effect of derivative instruments on the Consolidated Statements of Operations for the periods indicated:

		Amount of Gain or (Loss) Recognized in Income on Derivative		
		Successor	Predecessor	
Derivatives Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
		(In thousands)		
Commodity derivatives	Gain (loss) on derivatives, included are amounts settled during the period of $(1,133), $(4,244), and $16,196, respectively	$ (985)	$ (10,704)	$ 4,225
Total		$ (985)	$ (10,704)	$ 4,225

NOTE 16 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2—significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally 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.

The inputs available determine the valuation technique we use to measure the fair values presented in our financial instruments.

The following tables set forth our recurring fair value measurements:

	Successor			
	December 31, 2020			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$ 3,436	$ —	$ (3,436)	$ —
Liabilities	(9,142)	—	3,436	(5,706)
	$ (5,706)	$ —	$ —	$ (5,706)

	Predecessor			
	December 31, 2019			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$ 177	$ 1,204	$ (748)	$ 633
Liabilities	(775)	—	748	(27)
	$ (598)	$ 1,204	$ —	$ 606

All our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post any cash collateral with our counterparties and no collateral has been posted as of December 31, 2020.

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).

Level 2 Fair Value Measurements

Commodity Derivatives. We measure the fair values of our crude oil and natural gas swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

Commodity Derivatives. The fair values of our natural gas and crude oil collars are estimated using internal 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.

The following tables are reconciliations of our recurring level 3 fair value measurements:

	Net Derivatives		
	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
	(In thousands)		
Beginning of period	$ —	$ 1,204	$ 10,630
Total gains or losses:			
Included in earnings	—	978	(1,494)
Settlements	—	(2,182)	(7,932)
End of period	$ —	$ —	$ 1,204
Total gains (losses) for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	$ —	$ (1,204)	$ (9,426)

Based on our valuation at December 31, 2020, we determined that the non-performance risk regarding our counterparties was immaterial.

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.

At December 31, 2020, the carrying values on the Consolidated Balance Sheets for cash, restricted cash, and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short-term nature.

The Warrants are accounted for as a derivative liability as they are not indexed to the New Common Stock until all outstanding disputed claims against the company and UPC have been finally resolved and the strike price for the Warrants can be determined. Accordingly, the Warrants are recorded at their fair value using the Black-Scholes-Merton option model. The inputs to the model require various judgements, including estimating the strike price, expected term and the associated volatility. The Warrants are adjusted to fair value at each reporting period until determined to be an equity instrument, at which time they will be reported as shareholders' equity and no longer be subject to future fair value adjustment. At December 31, 2020, the Warrants have a fair value of $0.9 million. The Warrants are considered Level 3 fair value measurements.

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, 2020 would approximate its fair value. This debt is classified as Level 2.

The carrying amount of long-term debt, net of unamortized discount and debt issuance costs, associated with the Notes reported in the Consolidated Balance Sheets at December 31, 2019 was $646.7 million. On the Effective Date, our obligations with respect to the Notes were cancelled and holders of the Notes subsequently received their agreed on pro-rata share of New Common Stock. For further information, please see Note 2 – Emergence From Voluntary Reorganization Under Chapter 11. The estimated fair value of these Notes using quoted market prices at December 31, 2019 was $357.5 million. These Notes were classified as Level 2.

Fair Value of Non-Financial Instruments

The initial measurement of AROs at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant, and equipment. Significant Level 3 inputs used in the calculation of AROs include plugging costs and remaining reserve lives. A reconciliation of the company's AROs is presented in Note 10 – Asset Retirement Obligations.

Non-recurring fair value measurements are also applied, when applicable, to determine the fair value of our long-lived assets and goodwill. During 2020 and 2019, we recorded non-cash impairment charges discussed further in Note 4 – Summary Of Significant Accounting Policies. The valuation of these assets requires the use of significant unobservable inputs classified as Level 3.

See Note 3 - Fresh Start Accounting for additional disclosures of non-recurring fair value measurements associated with the qualification of fresh start under ASC 852.

NOTE 17 – LEASES

Operating Leases under ASC 842

Adoption of Accounting Standards Codification (ASC) Topic 842, "Leases." We adopted Topic 842 on January 1, 2019, using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative adjustment to equity. Results for reporting periods beginning after January 1, 2019, are presented under Topic 842, while prior periods are presented under ASC 840.

We determine whether a contract is or contains a lease at inception of the contract based on whether an identified asset exists and whether we have the right to obtain substantially all the benefit of the assets and to control its use over the full term of the agreement. When available, we use the rate explicit in the lease to discount lease payments to present value; however, most of our leases do not provide a readily determinable explicit rate. Therefore, we must estimate our incremental borrowing rate considering both the revolving credit rates and a credit notching approach to discount the lease payments based on information available at lease commencement. There are no material residual value guarantees and no restrictions or covenants included in our lease agreements. Certain of our leases include provisions for variable payments. These variable payments are typically determined based on a measure of throughput or actual days or another measure of usage and are not included in the calculation of lease liabilities and right-of-use assets.

Related to our oil and natural gas segment, our short-term lease costs include those that are recognized in profit or loss during the period and those that are capitalized as part of the cost of our full cost pool. As the costs related to our drilling and production activities are reflected at our net ownership consistent with the principals of proportional consolidation, and lease commitments are generally considered gross as the operator, the costs may not reasonably reflect the company’s short-term lease commitments.

Practical Expedients and Policies Elected. We elected the hindsight expedient, which allows us to use hindsight in assessing lease term; the package of practical expedients permitted under the guidance, which among other things, allowed us to carry forward the historical lease classification; and the land easement expedient, which allowed us to apply the guidance prospectively at adoption for land easements on existing agreements. We applied the short-term policy election, which allowed us to exclude from recognition on the balance sheet leases with an initial term of 12 months or less. We considered quantitative and qualitative factors when determining the application of the practical expedient that allowed us not to separate lease and non-lease components and are accounting for the agreements as a single lease component.

We routinely enter into related party agreements between our three segments. These agreements have been evaluated under the guidance of ASC 842. Our oil and natural gas segment may contract for the use of drilling equipment from our drilling segment. We have determined that the contracting of our drilling segment's drilling rigs will be accounted for under ASC 606 as the service has been deemed the predominate component of the contract per the lessor practical expedient.

Adoption. Adoption of Topic 842 resulted in new operating lease assets and lease liabilities on our Consolidated Balance Sheet of $3.7 million and $3.5 million, respectively, as of January 1, 2019, which represents noncash operating activity. The immaterial difference between the lease assets and lease liabilities was recorded as an adjustment to the beginning balance of retained earnings, which represents the cumulative impact of adopting the standard. Our accounting for finance leases remained substantially unchanged.

Lease Agreements. We lease certain office space, land, and equipment, including pipeline equipment and office equipment. Our lease payments are generally straight-line and the exercise of lease renewal options, which vary in term, is at our sole discretion. We include renewal periods in our lease term if we are reasonably certain to exercise available renewal options. Our lease agreements do not include options to purchase the leased property.

The following table sets forth the maturity of our operating lease liabilities as of December 31, 2020:

	Amount (In thousands)
Ending December 31,	
2021	$ 4,232
2022	1,305
2023	96
2024	12
2025	12
2026 and beyond	63
Total future payments	5,720
Less: Interest	200
Present value of future minimum operating lease payments	5,520
Less: Current portion	4,075
Total long-term operating lease payments	$ 1,445

Finance Leases under ASC 842

During 2014, our mid-stream segment entered into finance lease agreements for 20 compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The current portion of our finance lease obligations of $3.2 million is included in current portion of other long-term liabilities in the accompanying Consolidated Balance Sheets as of December 31, 2020. These finance leases are discounted using annual rates of 4.0%. Total maintenance and interest remaining related to these leases were $0.5 million at December 31, 2020. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

Future payments required under the finance leases at December 31, 2020 are as follows:

	Amount (In thousands)
Ending December 31,	
2021	$ 3,774
Total future payments	3,774
Less payments related to:	
Maintenance	525
Interest	33
Present value of future minimum payments	3,216
Less: Current portion	3,216
Total long-term finance lease payments	$ —

Information about our lease assets and liabilities included in our Consolidated Balance Sheets as of December 31, 2020 and 2019 are as follows:

	Classification on the Consolidated Balance Sheets	Successor December 31, 2020	Predecessor December 31, 2019
		(In thousands)	
Assets			
Operating right of use assets	Right of use assets	$ 5,592	$ 5,673
Finance right of use assets	Property, plant, and equipment, net	7,281	17,396
Total right of use assets		$ 12,873	$ 23,069
Liabilities			
Current liabilities:			
Operating lease liabilities	Current operating lease liabilities	$ 4,075	$ 3,430
Finance lease liabilities	Current portion of other long-term liabilities	3,216	4,164
Non-current liabilities:			
Operating lease liabilities	Operating lease liabilities	1,445	2,071
Finance lease liabilities	Other long-term liabilities	—	3,215
Total lease liabilities		$ 8,736	$ 12,880

The following table shows certain information related to the lease costs for our finance and operating leases for the periods indicated:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	Year Ended December 31, 2019
		(In thousands)	
Components of total lease cost:			
Amortization of finance leased assets	$ 1,406	$ 2,757	$ 4,001
Interest on finance lease liabilities	54	165	382
Operating lease cost	1,331	3,604	4,034
Short-term lease cost, included are amounts capitalized related to our oil and natural gas segment of less than $0.2 million, $1.5 million, and $24.7 million, respectively	3,664	8,190	38,868
Variable lease cost	64	223	351
Total lease cost	$ 6,519	$ 14,939	$ 47,636

The following table provides supplemental cash flow information related to leases for the periods indicated:

	Successor	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	Year Ended December 31, 2019
		(In thousands)	
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows for operating leases	$ 1,489	$ 3,849	$ 4,034
Financing cash flows for finance leases	1,407	2,757	4,001
Lease liabilities recognized in exchange for new operating lease right of use assets	—	—	5

The following table shows certain information related to the weighted average remaining lease terms and the weighted average discount rates for our operating and finance leases at December 31, 2020:

	Weighted Average Remaining Lease Term	Weighted Average Discount Rate [(1)]
	(In years)	
Operating leases	1.6	4.41%
Finance leases	0.7	4.00%

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.

We lease office space in Oklahoma City, Oklahoma; Houston and Odessa, Texas; Englewood, Colorado; and Pinedale, Wyoming under the terms of operating leases expiring through January 2022. We also have compressor rentals, equipment leases, and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

NOTE 18 – COMMITMENTS AND CONTINGENCIES

Commitments

Our mid-stream segment has firm transportation commitments to transport our natural gas from various systems for approximately $1.0 million over the next twelve months and $0.4 million for the one year thereafter.

During the second quarter of 2018, as part of the Superior transaction (see Note 19 – Variable Interest Entity Arrangements), we entered into a contractual obligation committing us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. For each dollar of the $150.0 million we do not spend (over the three-year period), we would forgo receiving $0.58 of future distributions from our ownership interest in our consolidated mid-stream subsidiary. At December 31, 2020, if we elected not to drill or spend any additional money in the designated area before December 31, 2021, the maximum amount we could forgo from distributions would be $72.6 million. Total spent towards the $150.0 million as of December 31, 2020 was $24.8 million. We do not anticipate meeting the contractual obligation over the remaining commitment period.

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. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of 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 any significant environmental liabilities while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the drilling rig is on the location and the cost has been included 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, or more routine employment related claims. The company accrues for such items when a liability is both probable and the amount can be reasonably estimated. As new information becomes available or because of legal or administrative rulings in similar matters or a change in applicable law, the company's conclusions regarding the probability of outcomes and the amount of estimated loss, if any, may change. Although we are insured against various risks, there is no assurance that the nature and amount of that insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings.

On 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. For further information on the Chapter 11 Cases, please see Note 2 – Emergence From Voluntary Reorganization Under Chapter 11.

In 2013, the company's exploration and production subsidiary, Unit Petroleum Company (UPC), drilled a well in Beaver County, Oklahoma. 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 it was pending review in the Oklahoma Court of Civil Appeals. In February 2021, UPC finalized a settlement agreement with the working interest owner for $2.1 million in damages. As of December 31, 2020, the company's total accrual for loss contingencies was $2.1 million.

Below is a summary of two other lawsuits and the respective treatment of those cases in the Chapter 11 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 Company 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. 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.

Pending Settlement

In August 2020, UPC reached an agreement to settle these class actions. Under the settlement, UPC agreed to recognize class proofs 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. This settlement is subject to certain conditions, including approval 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.* Under the Plan, these settlement amounts will be treated as allowed general unsecured claims against UPC. The settlement amounts will be satisfied by distribution of the plaintiffs' proportionate share of New Common Stock in accordance with the Plan.

Subsequent Event: Winter Storm

In February of 2021, a severe winter storm impacted many of our operating areas in Oklahoma, Texas, and Kansas, resulting in certain disruptions to our operations. Although some uncertainties remain as to the ultimate impact and severity of these disruptions, we do not believe any such matters will have a material impact on our financial position.

NOTE 19 – VARIABLE INTEREST ENTITY ARRANGEMENTS

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 Holdings, LLC, 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 the 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 $260,560. Superior's creditors have no recourse to our general credit. Unit 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.

The Agreement specifies how future distributions are to be allocated among the Members. Future distributions may be from available cash or made in conjunction with a sale event (both as defined in the Agreement). In certain circumstances, future distributions could result in Unit receiving distributions that are disproportionately lower than its ownership percentage. Circumstances that could result in Unit receiving less than a proportionate share of future distributions include, but may not be limited to, Unit not fulfilling the drilling commitment described in Note 18 – Commitments and Contingencies or a cumulative return to SP Investor Holdings, LLC of less than the 7% Liquidation IRR Hurdle provided for SP Investor Holdings, LLC in the Agreement. Generally, the 7% Liquidation IRR Hurdle calculation requires cumulative distributions to SP Investor Holdings, LLC in excess of its original $300.0 million investment sufficient to provide SP Investor Holdings, LLC a 7% IRR on its capital contributions to Superior before any liquidation distribution is made to Unit. After the fifth anniversary of the effective date of the sale, either owner may force a sale of Superior to a third-party or a liquidation of Superior's assets.

Effective at emergence, we record our share of earnings and losses from Superior using the HLBV method of accounting. The HLBV is a balance-sheet approach that calculates the amount we would have received if Superior were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our Consolidated Statements of Operations. On the sale or liquidation of Superior, distributions would occur in the order and priority specified in the relevant agreements.

Under the guidance in ASC 810, *Consolidation*, we have determined that Superior is a VIE. The two variable interests applicable to Unit include the 50% equity investment in Superior and the MSA. The MSA gives us the power to direct the activities that most significantly affect Superior's operating performance. The MSA is a separate variable interest. Under the MSA, Unit has the power to direct Superior’s most significant activities; reciprocally the equity investors lack the power to direct the activities that most affect the entity’s economic performance. Because of this, Unit is considered the primary beneficiary. There have been no changes to the primary beneficiary as of December 31, 2020.

As the primary beneficiary of this VIE, we consolidate in the financial statements the financial position, results of operations and cash flows of this VIE. All intercompany balances and transactions between us and the VIE are eliminated in the consolidated financial statements. Cash distributions of income, net of agreed on expenses, and estimated expenses are allocated to the equity owners as specified in the relevant agreements.

With consolidation of the VIE, the assets and liabilities of Superior were subject to fair value adjustments in accordance with ASC 852, *Reorganizations.* Therefore, the periods presented below are not comparative. The assets and liabilities of Superior at December 31, 2020 include the company’s application of fresh start accounting as described in Note 3 - Fresh Start Accounting, while the asset and liabilities at December 31, 2019, reflect historical basis, prior to any fresh start accounting adjustments. The amounts below reflect the eliminations of intercompany transactions and balances consistent with the presentation in the Consolidated Balance Sheets.

	December 31, 2020	December 31, 2019
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 11,642	$ —
Accounts receivable	27,427	21,073
Prepaid expenses and other	6,746	7,686
Total current assets	45,815	28,759
Property and equipment:		
Gas gathering and processing equipment	251,403	824,699
Transportation equipment	1,748	3,390
	253,151	828,089
Less accumulated depreciation, depletion, amortization, and impairment	10,466	407,144
Net property and equipment	242,685	420,945
Right of use assets	2,823	3,948
Other assets	2,309	9,442
Total assets	$ 293,632	$ 463,094
Current liabilities:		
Accounts payable	$ 17,045	$ 18,511
Accrued liabilities	3,777	4,198
Current operating lease liability	1,762	2,407
Current portion of other long-term liabilities	5,799	7,060
Total current liabilities	28,383	32,176
Long-term debt less debt issuance costs	—	16,500
Operating lease liability	1,013	1,404
Other long-term liabilities	1,589	8,126
Total liabilities	$ 30,985	$ 58,206

NOTE 20 – 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 table provides certain information about the operations of each of our segments:

	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

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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 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.

	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

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 $64.0 million pre-tax write-down for certain long-lived asset groups.

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

	Predecessor					
	Year Ended December 31, 2019					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 325,797	$ —	$ —	$ —	$ —	$ 325,797
Contract drilling	—	184,192	—	—	(15,809)	168,383
Gas gathering and processing	—	—	227,939	—	(47,485)	180,454
Total revenues [1]	325,797	184,192	227,939	—	(63,294)	674,634
Expenses:						
Operating costs:						
Oil and natural gas	140,026	—	—	—	(4,902)	135,124
Contract drilling	—	130,188	—	—	(14,190)	115,998
Gas gathering and processing	—	—	176,189	—	(42,583)	133,606
Total operating costs	140,026	130,188	176,189	—	(61,675)	384,728
Depreciation, depletion, and amortization	168,651	51,552	47,663	7,707	—	275,573
Impairments [2]	559,867	62,809	3,040	—	—	625,716
Total expenses	868,544	244,549	226,892	7,707	(61,675)	1,286,017
General and administrative	—	—	—	38,246	—	38,246
(Gain) loss on disposition of assets	(199)	3,872	(160)	(11)	—	3,502
Income (loss) from operations	(542,548)	(64,229)	1,207	(45,942)	(1,619)	(653,131)
Gain on derivatives	—	—	—	4,225	—	4,225
Interest expense, net	—	—	(1,546)	(35,466)	—	(37,012)
Other	(481)	(605)	827	23	—	(236)
Income (loss) before income taxes	$ (543,029)	$ (64,834)	$ 488	$ (77,160)	$ (1,619)	$ (686,154)
Identifiable assets:						
Oil and natural gas [3]	851,662	—	—	—	(4,264)	847,398
Contract drilling	—	708,510	—	—	(42)	708,468
Gas gathering and processing	—	—	463,699	—	(4,255)	459,444
Total identifiable assets [4]	851,662	708,510	463,699	—	(8,561)	2,015,310
Corporate land and building	—	—	—	54,155	—	54,155
Other corporate assets [5]	—	—	—	23,092	(2,505)	20,587
Total assets	$ 851,662	$ 708,510	$ 463,699	$ 77,247	$ (11,066)	$ 2,090,052
Capital expenditures:	$ 268,622	$ 40,636	$ 64,438	$ 673	$ —	$ 374,369

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. We incurred non-cash ceiling test write-downs of our oil and natural gas properties of $559.4 million pre-tax ($422.4 million, net of tax). We also recognized goodwill impairment charges of $62.8 million pre-tax ($59.8 million, net of 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.

NOTE 21 – SELECTED QUARTERLY FINANCIAL INFORMATION

Summarized unaudited quarterly financial information is as follows:

	First Quarter		Second Quarter		Third Quarter [1]		Fourth Quarter	
	(In thousands except per share amounts)							
2020 (Successor)								
Revenues	$ —		$ —		$ 32,846		$ 100,682	
Gross income (loss) [2]	$ —		$ —		$ (7,373)		$ 5,599	
Net loss attributable to Unit Corporation	$ —		$ —		$ (8,968)	(3)	$ (9,172)	(4)
Net loss attributable to Unit Corporation per common share:								
Basic	$ —		$ —		$ (0.75)		$ (0.76)	
Diluted	$ —		$ —		$ (0.75)		$ (0.76)	
2020 (Predecessor)								
Revenues	$ 122,376		$ 89,007		$ 65,574		$ —	
Gross loss[2]	$ (764,888)		$ (171,374)		$ (7,637)		$ —	
Net income (loss) attributable to Unit Corporation	$ (770,494)	(5)	$ (215,649)	(6)	$ 55,131	(7)	$ —	
Net income (loss) attributable to Unit Corporation per common share:								
Basic	$ (14.50)		$ (4.03)		$ 1.03		$ —	
Diluted	$ (14.50)		$ (4.03)		$ 1.03		$ —	
2019 (Predecessor)								
Revenues	$ 189,691		$ 165,146		$ 155,439		$ 164,358	
Gross income (loss) [2]	$ 24,095		$ 813		$ (242,308)		$ (393,983)	
Net loss attributable to Unit Corporation	$ (3,504)		$ (8,509)		$ (206,886)	(8)	$ (334,980)	(9)
Net loss attributable to Unit Corporation per common share:								
Basic	$ (0.07)		$ (0.16)		$ (3.91)		$ (6.33)	
Diluted	$ (0.07)		$ (0.16)		$ (3.91)		$ (6.33)	

1. Third quarter for the 2020 Predecessor Period is for the period July 1, 2020 through August 31, 2020. Third quarter for the 2020 Successor Period is the period September 1, 2020 through September 30, 2020.
2. Gross income (loss) excludes general and administrative expense, interest expense, (gain) loss on disposition of assets, loss on abandonment of assets, gain (loss) on derivatives, reorganization items, net, income taxes, and other income (loss).
3. During the one-month Successor Period for the third quarter of 2020, we recorded a non-cash ceiling test write-down of $13.2 million pre-tax.
4. During the fourth quarter of 2020, we recorded a non-cash ceiling test write-down of $12.9 million pre-tax.
5. During the first quarter of 2020, we recorded a non-cash ceiling test write-down of $267.8 million pre-tax ($220.8 million, net of tax). We also recorded total expense of $17.6 million related to the abandonment of salt water disposal assets, $407.1 million related to the write-down of the SCR drilling rigs, $3.0 million related to the write-down of other miscellaneous drilling equipment, and $64.0 million related to the write-down of mid-stream assets.
6. During the second quarter of 2020, we recorded a non-cash ceiling test write-down of $109.3 million pre-tax.
7. During the two months ended August 31, 2020, we recorded a non-cash test write-down of $16.6 million pre-tax and $1.2 million related to the abandonment of other miscellaneous drilling equipment. We also recorded $141.0 million gain in reorganization items, net.
8. During the third quarter of 2019, we recorded a non-cash ceiling test write-down of $169.3 million pre-tax ($127.9 million, net of tax). We also recognized goodwill impairment charges of $62.8 million, pre-tax ($59.8 million, net of tax).
9. During the fourth quarter of 2019, we recorded a non-cash ceiling test write-down of $390.1 million pre-tax ($294.5 million, net of tax).

NOTE 22 – 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 Successor 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.

Condensed Consolidating Balances Sheets

	Predecessor				
	December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ 503	$ 68	$ —	$ —	$ 571
Accounts receivable, net of allowance for doubtful accounts of $2,332 (Guarantor of $1,116 and Parent of $1,216)	2,645	64,805	24,653	(9,447)	82,656
Materials and supplies	—	449	—	—	449
Current derivative asset	633	—	—	—	633
Income tax receivable	1,756	—	—	—	1,756
Assets held for sale	—	5,908	—	—	5,908
Prepaid expenses and other	2,019	3,373	7,686	—	13,078
Total current assets	7,556	74,603	32,339	(9,447)	105,051
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	6,341,582	—	—	6,341,582
Unproved properties not being amortized	—	252,874	—	—	252,874
Drilling equipment	—	1,295,713	—	—	1,295,713
Gas gathering and processing equipment	—	—	824,699	—	824,699
Saltwater disposal systems	—	69,692	—	—	69,692
Corporate land and building	—	59,080	—	—	59,080
Transportation equipment	9,712	16,621	3,390	—	29,723
Other	28,927	29,065	—	—	57,992
	38,639	8,064,627	828,089	—	8,931,355
Less accumulated depreciation, depletion, amortization, and impairment	33,794	6,537,731	407,144	—	6,978,669
Net property and equipment	4,845	1,526,896	420,945	—	1,952,686
Intercompany receivable	1,048,785	—	—	(1,048,785)	—
Investments	865,252	—	—	(865,252)	—
Right of use asset	46	1,733	3,948	(54)	5,673
Other assets	8,107	9,094	9,441	—	26,642
Total assets	$ 1,934,591	$ 1,612,326	$ 466,673	$ (1,923,538)	$ 2,090,052

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

	Predecessor				
	December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 12,259	$ 61,002	$ 18,511	$ (7,291)	$ 84,481
Accrued liabilities	28,003	14,024	6,691	(2,156)	46,562
Current operating lease liability	20	1,009	2,407	(6)	3,430
Current portion of long-term debt	108,200	—	—	—	108,200
Current portion of other long-term liabilities	3,003	7,313	7,060	—	17,376
Total current liabilities	151,485	83,348	34,669	(9,453)	260,049
Intercompany debt	—	1,047,599	1,186	(1,048,785)	—
Long-term debt less debt issuance costs	646,716	—	16,500	—	663,216
Non-current derivative liability	27	—	—	—	27
Operating lease liability	25	690	1,404	(48)	2,071
Other long-term liabilities	12,553	74,662	8,126	—	95,341
Deferred income taxes	68,150	(54,437)	—	—	13,713
Total shareholders' equity	1,055,635	460,464	404,788	(865,252)	1,055,635
Total liabilities and shareholders' equity	$ 1,934,591	$ 1,612,326	$ 466,673	$ (1,923,538)	$ 2,090,052

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)

	Predecessor				
	Twelve Months Ended December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 494,180	$ 227,939	$ (47,485)	$ 674,634
Expenses:					
Operating costs	—	256,024	176,189	(47,485)	384,728
Depreciation, depletion, and amortization	7,707	220,203	47,663	—	275,573
Impairments	—	622,676	3,040	—	625,716
General and administrative	—	38,246	—	—	38,246
(Gain) loss on disposition of assets	(11)	3,673	(160)	—	3,502
Total operating costs	7,696	1,140,822	226,732	(47,485)	1,327,765
Income (loss) from operations	(7,696)	(646,642)	1,207	—	(653,131)
Interest, net	(35,466)	—	(1,546)	—	(37,012)
Gain on derivatives	4,225	—	—	—	4,225
Other, net	786	(1,086)	64	—	(236)
Loss before income taxes	(38,151)	(647,728)	(275)	—	(686,154)
Income tax expense (benefit)	7,238	(139,564)	—	—	(132,326)
Equity in net earnings from investment in subsidiaries, net of taxes	(508,439)	—	—	508,439	—
Net loss	(553,828)	(508,164)	(275)	508,439	(553,828)
Less: net income attributable to non-controlling interest	51	—	51	(51)	51
Net loss attributable to Unit Corporation	$ (553,879)	$ (508,164)	$ (326)	$ 508,490	$ (553,879)

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)

	Predecessor				
	Twelve Months Ended December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net loss	$ (553,828)	$ (508,164)	$ (275)	$ 508,439	$ (553,828)
Other comprehensive loss, net of taxes:					
Reclassification adjustment for write-down of securities, net of tax $(47)	—	481	—	—	481
Comprehensive loss	(553,828)	(507,683)	(275)	508,439	(553,347)
Less: Comprehensive income attributable to non-controlling interests	51	—	51	(51)	51
Comprehensive loss attributable to Unit Corporation	$ (553,879)	$ (507,683)	$ (326)	$ 508,490	$ (553,398)

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

	Predecessor				
	Twelve Months Ended December 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (9,681)	$ 217,883	$ 48,856	$ 12,338	$ 269,396
INVESTING ACTIVITIES:					
Capital expenditures	65	(355,258)	(51,472)	—	(406,665)
Producing properties and other acquisitions	—	(3,653)	—	—	(3,653)
Other acquisitions	—	—	(16,109)	—	(16,109)
Proceeds from disposition of assets	11	31,153	700	—	31,864
Net cash provided by (used in) investing activities	76	(327,758)	(66,881)	—	(394,563)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	400,600	—	92,900	—	493,500
Payments under credit agreement	(292,400)	—	(76,400)	—	(368,800)
Intercompany borrowings (advances), net	(97,455)	109,735	58	(12,338)	—
Payments on finance leases	—	—	(4,001)	—	(4,001)
Employee taxes paid by withholding shares	(4,158)	—	—	—	(4,158)
Distributions to non-controlling interest	919	—	(1,837)	—	(918)
Bank overdrafts	2,199	—	1,464	—	3,663
Net cash provided by (used in) financing activities	9,705	109,735	12,184	(12,338)	119,286
Net increase (decrease) in cash and cash equivalents	100	(140)	(5,841)	—	(5,881)
Cash and cash equivalents, beginning of period	403	208	5,841	—	6,452
Cash and cash equivalents, end of period	$ 503	$ 68	$ —	$ —	$ 571

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 at year end were as follows:

	Successor	Predecessor
	2020	2019
	(In thousands)	
Proved properties	$ 238,581	$ 6,341,582
Unproved properties (wells in progress)	1,591	252,874
	240,172	6,594,456
Accumulated depreciation, depletion, amortization, and impairment	(40,806)	(5,846,177)
Net capitalized costs	$ 199,366	$ 748,279

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	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
	(In thousands)		
Unproved properties acquired	$ 26	$ 2,373	$ 34,668
Proved properties acquired	—	382	3,653
Exploration	—	—	16,480
Development	3,992	6,440	211,443
Asset retirement obligation	(1,702)	(29,189)	76
Total costs incurred	$ 2,316	$ (19,994)	$ 266,320

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	Predecessor	
	Period September 1, 2020 through December 31, 2020	Period January 1, 2020 through August 31, 2020	For the Year Ended December 31, 2019
	(In thousands)		
Revenues	$ 55,272	$ 96,033	$ 314,925
Production costs	(20,510)	(46,633)	(116,051)
Depreciation, depletion, amortization, and impairment	(40,840)	(461,901)	(727,529)
	(6,078)	(412,501)	(528,655)
Income tax (expense) benefit	128	6,698	101,952
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ (5,950)	$ (405,803)	$ (426,703)

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 Bbls	NGLs Bbls	Natural Gas Mcf	Total MBoe
	(In thousands)			
2019				
Proved developed and undeveloped reserves:				
Beginning of year	22,558	47,796	535,963	159,681
Revision of previous estimates [1]	(8,263)	(20,961)	(234,852)	(68,366)
Extensions and discoveries [1]	703	845	8,798	3,015
Infill reserves in existing proved fields	271	434	4,806	1,506
Purchases of minerals in place	183	101	1,316	503
Production	(3,208)	(4,773)	(53,064)	(16,825)
Sales	(48)	(412)	(42,780)	(7,590)
Net proved reserves at December 31, 2019	12,196	23,030	220,187	71,924
Proved developed reserves, December 31, 2019	12,196	23,030	220,187	71,924
Proved undeveloped reserves, December 31, 2019	—	—	—	—
2020				
Proved developed and undeveloped reserves:				
Beginning of year	12,196	23,030	220,187	71,924
Revision of previous estimates	(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	—	—	—	—

1. Revisions of previous estimates and extensions and discoveries 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.

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 is as follows:

	Successor	Predecessor
	2020	2019
	(In thousands)	
Future cash flows	$ 698,685	$ 1,386,777
Future production costs	(416,095)	(698,357)
Future development costs	—	—
Future income tax expenses	(39)	(321)
Future net cash flows	282,551	688,099
10% annual discount for estimated timing of cash flows	(89,530)	(226,390)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 193,021	$ 461,709

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

	2020	2019
Sales and transfers of oil and natural gas produced, net of production costs	$ (84,163)	$ (200,233)
Net changes in prices and production costs	(165,978)	(508,066)
Revisions in quantity estimates and changes in production timing	(50,979)	(338,994)
Extensions, discoveries, and improved recovery, less related costs	2,827	53,123
Changes in estimated future development costs	—	311,190
Previously estimated cost incurred during the period	—	64,362
Purchases of minerals in place	852	6,416
Sales of minerals in place	(46)	(25,813)
Accretion of discount	46,203	110,571
Net change in income taxes	282	121,708
Changes in timing and other	(17,686)	(116,233)
Net change	(268,688)	(521,969)
Beginning of year	461,709	983,678
End of year	$ 193,021	$ 461,709

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, 2020, future cash flows were computed by applying the unescalated 12-month average prices of $39.57 per barrel for oil, $18.70 per barrel for NGLs, and $1.98 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 Interim Chief Financial Officer (Interim 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 (ICFR) (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 ICFR and make modifications as necessary; our intent in this regard is that the Disclosure Controls and ICFR 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 Interim 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 Interim CFO concluded that our disclosure controls and procedures were not effective as of December 31, 2020 due to a material weakness in ICFR described below.

Notwithstanding the material weakness, management has concluded that our consolidated financial statements included in this Form 10-K are fairly stated in all material respects in accordance with generally accepted accounting principles in the United States of America for each of the periods presented.

Management's 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 Interim 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 not effective as of December 31, 2020 due to the material weakness discussed below.

A material weakness is a deficiency, or combination of deficiencies, in ICFR, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis.

As previously disclosed in our Quarterly Report on Form 10-Q for the period ended June 30, 2020, in preparing our interim financial statements for the quarterly period ended June 30, 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 at June 30, 2020 or not present for a sufficient period of time in order to conclude our disclosure controls and procedures were effective at June 30, 2020. This continued to be the case at December 31, 2020.

Plan for Remediation of the Material Weakness

We continue to address the underlying cause of the material weakness, including a redesign of certain management review controls related to complex accounting matters, the establishment of documentation standards, assessing the structure of the accounting organization, providing additional training for employees responsible for performing important management review controls, and supplementing internal resources with external expertise when appropriate.

We have also hired new personnel in key positions and continue to evaluate the need for additional personnel to further enhance the overall control environment.

Our management believes the measures described above will eventually remediate this material weakness. As management continues to evaluate and improve internal control over financial reporting, we may decide to take additional measures to address this control deficiency or determine to modify, or in appropriate circumstances not to complete, certain of the remediation measures. However, this material weakness will not be considered remediated until the applicable remedial controls operate for a sufficient period of time and management has tested the effectiveness of those controls.

Changes in Internal Control Over Financial Reporting

Other than the remediation measures described above, there were no changes in ICFR during the quarter ended December 31, 2020, that materially affected our ICFR or are reasonably likely to materially affect it.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

In accordance with Instruction G(3) of Form 10-K, the information required by this item will be included in an amendment to this Form 10-K or incorporated by reference from the registrants' definitive Proxy Statement to be filed pursuant to Regulation 14A, except for the information regarding our executive officers which is presented below.

Our Code of Business Conduct and Ethics applies to all directors, officers, and employees, including our Chief Executive Officer, our Interim Chief Financial Officer, and our Controller. You can find our Code of Business Conduct and Ethics on our internet website, www.unitcorp.com. We will post any amendments to the Code of Business Conduct and Ethics, and any waivers that are required to be disclosed by applicable rules on our internet website.

We have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our Chief Executive Officer and Interim Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Information About Our Executive Officers

The table below and accompanying text sets forth certain information as of March 10, 2021 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	POSITION HELD
Philip B.Smith	69	Director since September 3, 2020, Chairman since September 8, 2020, President and Chief Executive Officer since October 22, 2020
Mark E. Schell*	63	Executive Vice President and Chief Strategy Officer since October 27, 2020, Senior Vice President from December 2002 to October 27, 2020, General Counsel and Corporate Secretary since January 1987
Andrew E. Harding	43	Vice President, Secretary, and General Counsel since October 27, 2020, Associate General Counsel from 2004 to October 27, 2020
Thomas D. Sell	56	Interim Chief Financial Officer since October 22, 2020 and Chief Accounting Officer since December 31, 2020
David P. Dunham	41	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
Christopher K. Menefee	43	President, Unit Drilling Company since November 9, 2020
Michael L. Hicks	55	Manager and President, Superior Pipeline Company, L.L.C. since April 1, 2020

* Effective March 31, 2021, Mr. Schell has stepped down from the company.

Philip B. Smith. Mr. Smith was named to the Board of Directors on September 3, 2020 and became Chair 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 NGP in 1999, until the Company’s merger with Magnum Hunter Resources in 2002. Mr. Smith also served as CEO of Tide West Oil Company until it was sold to HS Resources in 1997. He received a B.S. in Mechanical Engineering from Oklahoma State University and a Master of Business Administration from the University of Tulsa.

Mark E. Schell. Mr. Schell joined Unit in January 1987 as its Secretary and General Counsel. In 2003, he was promoted to Senior Vice President. In 2020, he was promoted to Executive Vice President and Chief Strategy Officer. From 1979 until joining Unit Corporation, Mr. Schell was Counsel, Vice President, and a member of the Board of Directors of C & S Exploration Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa College of Law. He is a member of the Oklahoma Bar Association.

Andrew E. Harding. 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.

David P. Dunham. 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 elected to Chief Operating Officer. 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 MBA from The Wharton School of the University of Pennsylvania.

Thomas D. Sell. Mr. Sell joined Unit in October 2020 as Interim Chief Financial Officer. From March 2020 to October 2020, he was the Chief Financial Officer for Montereau, Inc. From 2016 to March 2020, Mr. Sell served as Chief Accounting Officer and Controller for SemGroup Corporation. 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.

Christopher K. Menefee. 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 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.

Michael L. Hicks. Mr. Hicks joined Superior Pipeline Company, LLC in April 2013 as Vice President of Operations. In December 2014, he was promoted to Senior Vice President of Operations and Engineering. In June 2019, he was promoted to the position of Chief Operating Officer, and effective April 1, 2020, he became President. From 2011 to April 2013, Mr. Hicks worked as the Executive Vice President - Operations for Aka Energy Group. From 2007 to 2011, he was the President of Frontier Field Services and Lumen Midstream Services, both owned by the Aka Energy Group, which is part of the Southern Ute Growth Fund. Mr. Hicks held numerous other positions within Frontier Energy, CMS Field Services, Dynegy, and Warren Petroleum. Mr. Hicks earned a Bachelor of Science in Chemical Engineering from the University of Tulsa in 1988.

Item 11. Executive Compensation

In accordance with Instruction G(3) of Form 10-K, the information required by this item will be included in an amendment to this Form 10-K or incorporated by reference from the registrants' definitive Proxy Statement to be filed pursuant to Regulation 14A (see Item 10 above).

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

None.

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

In accordance with Instruction G(3) of Form 10-K, the information required by this item will be included in an amendment to this Form 10-K or incorporated by reference from the registrants' definitive Proxy Statement to be filed pursuant to Regulation 14A (see Item 10 above).

Item 14. Principal Accounting Fees and Services

In accordance with Instruction G(3) of Form 10-K, the information required by this item will be included in an amendment to this Form 10-K or incorporated by reference from the registrants' definitive Proxy Statement to be filed pursuant to Regulation 14A (see Item 10 above).

PART IV

Item 15. Exhibits, 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, 2020 and 2019
Consolidated Statements of Operations for the Successor Period and Predecessor Period of 2020 and the year ended December 31, 2019
Consolidated Statements of Comprehensive Income (Loss) for the Successor Period and Predecessor Period of 2020 and the year ended December 31, 2019
Consolidated Statements of Changes in Shareholders' Equity for the Successor Period and Predecessor Period of 2020 and the year ended December 31, 2019
Consolidated Statements of Cash Flows for the for the Successor Period and Predecessor Period of 2020 and the year ended December 31, 2019
Notes to Consolidated Financial Statements

2. *Financial Statement Schedules:*

Included in Part IV of this report for the years ended December 31, 2020 and 2019:

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, dates as of September 3, 2020 (filed as Exhibit 3.1 to Unit's Form 8-K, dated September 10, 2020, 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†	Employment Agreement, dated as of September 3, 2020, by and between Unit Corporation and David T. Merrill (filed as Exhibit 10.2 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.3†	Employment Agreement, dates as of September 3, 2020, by and between Unit Corporation and Mark Schell (filed as Exhibit 10.3 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.4†	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).
10.5†	Amended and Restated Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.4 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.6†	Amended and Restated Special Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.5 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.7†	Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.6 to Unit's Form 8-K, dated September 10, 2020, which is incorporated by reference herein).
10.8	Amended and Restated Credit Agreement, dated as of September 3, 2020, among the 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).
10.9	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).
10.10	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 dates August 9, 2018, which is incorporated by reference herein).
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15	Amendment No. 1 to the 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).
10.16	Standstill and Amendment Agreement, dated as of March 11, 2020, by and among Unit Corporation, Unit Drilling Company, Unit Petroleum Company, the lenders party thereto and BOKF, NA dba Bank of Oklahoma, as administrative agent for the lenders (filed as Exhibit 10.1 to Unit's Form 8-K, dated March 16, 2020, which is incorporated by reference herein).
10.17	First Amendment to Standstill and Amendment Agreement, dated as of April 15, 2020, by and among Unit Corporation, Unit Drilling Company, Unit Petroleum Company, the lenders party thereto and BOKF, NA dba Bank of Oklahoma, as administrative agent for the lenders (filed as Exhibit 10.1 to Unit's Form 8-K, dated April 16, 2020, which is incorporated by reference herein).
10.18	Second Amendment to Standstill and Amendment Agreement, dated as of April 17, 2020, by and among Unit Corporation, Unit Drilling Company, Unit Petroleum Company, and BOKF, NA dba Bank of Oklahoma, as administrative agent on behalf of the lenders (filed as Exhibit 10.1 to Unit's Form 8-K, dated April 22, 2020, which is incorporated by reference herein).
10.19	Third Amendment to Standstill and Amendment Agreement, dated as of May 4, 2020, by and among Unit Corporation, Unit Drilling Company, Unit Petroleum Company, and BOKF, NA dba Bank of Oklahoma, as administrative agent on behalf of the lenders (filed as Exhibit 10.1 to Unit's Form 8-K, dated May 5, 2020, which is incorporated by reference herein).
10.20	Fourth Amendment to Standstill and Amendment Agreement, dated as of May 15, 2020, by and among Unit Corporation, Unit Drilling Company, Unit Petroleum Company, and BOKF, NA dba Bank of Oklahoma, as administrative agent on behalf of the lenders (filed as Exhibit 10.1 to Unit's Form 8-K, dated May 21, 2020, which is incorporated by reference herein).

10.21†	First Amendment to the Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.2 to Unit's Form 8-K, dated May 21, 2020, which is incorporated by reference herein).
10.22†	First Amendment to the Special Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as Exhibit 10.3 to Unit's Form 8-K, dated May 21, 2020, which is incorporated by reference herein).
10.23	Restructuring Support Agreement, dated as of May 22, 2020, by and among Unit Corporation, Unit Petroleum Company, Unit Drilling Company, 8200 Unit Drive, L.L.C., Unit Drilling USA Colombia, L.L.C., Unit Drilling Colombia L.L.C., the Consenting RBL Lenders party thereto, BOKF, NA dba Bank of Oklahoma as RBL Agent, and the Consenting Noteholders party thereto (filed as Exhibit 10.1 to Unit's Form 8-K, dated May 26, 2020, which is incorporated by reference herein).
10.24	Continuation Agreement, dated as of May 22, 2020, by and among Superior Pipeline Company, L.L.C., Unit Corporation, SPC Midstream Operating, L.L.C., SP Investor Holdings, LLC, 8200 Unit Drive, L.L.C., Unit Drilling Colombia, L.L.C., Unit Drilling Company, Unit Drilling USA Colombia, L.L.C. and Unit Petroleum Company (filed as Exhibit 10.2 to Unit's Form 8-K, dated May 26, 2020, which is incorporated by reference herein).
10.25	Fifth Amendment to Standstill and Amendment Agreement, dated as of May 22, 2020, by and among Unit Corporation, Unit Drilling Company, Unit Petroleum Company and BOKF, NA dba Bank of Oklahoma as administrative agent on behalf of the lenders (filed as Exhibit 10.3 to Unit's Form 8-K, dated May 26, 2020, which is incorporated by reference herein).
10.26	Superpriority Senior Secured Debtor-in-Possession Credit Agreement, dated as of May 27, 2020, by and among Unit Corporation, Unit Petroleum Company, Unit Drilling Company, 8200 Unit Drive, L.L.C., Unit Drilling USA Colombia, L.L.C., Unit Drilling Columbia L.L.C., the lenders party thereto and BOKF, NA dba Bank of Oklahoma as Administrative Agent (filed as Exhibit 10.1 to Unit's Form 8-K, dated June 1, 2020, which is incorporated by reference herein).
10.27†	Form of Indemnification Agreement between Unit Corporation and its executive officers and directors (filed herewith).
10.28†	Form of Director Engagement Letter (filed herewith).
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 Doubtful Accounts:

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, 2020	$ 2,332	$ 3,155	$ (1,704)	$ 3,783
Year ended December 31, 2019	$ 2,531	$ 527	$ (726)	$ 2,332

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, 2021

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, 2021.

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 Accounting Officer and Interim Chief Financial Officer (Principal Financial 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

INDEMNIFICATION AGREEMENT

This Indemnification Agreement ("Agreement") is made as of ________ ___, 2020 by and between Unit Corporation, a Delaware corporation (the "Company"), and __________________ ("Indemnitee"). This Agreement supersedes and replaces any and all previous agreements between the Company and Indemnitee covering the subject matter of this Agreement.

RECITALS

WHEREAS, the Board of Directors of the Company (the "Board") believes that highly competent persons have become more reluctant to serve publicly held corporations as **[directors] [officers]** or in other capacities unless they are provided with adequate protection through insurance or adequate indemnification against inordinate risks of claims and actions against them arising out of their service to and activities on behalf of the corporation;

WHEREAS, the Board has determined that, in order to attract and retain qualified individuals, the Company will attempt to maintain on an ongoing basis, at its sole expense, liability insurance to protect persons serving the Company and its subsidiaries from certain liabilities. Although the furnishing of such insurance has been a customary and widespread practice among United States-based corporations and other business enterprises, the Company believes that, given current market conditions and trends, such insurance may be available to it in the future only at higher premiums and with more exclusions. At the same time, directors, officers, and other persons in service to corporations or business enterprises are being increasingly subjected to expensive and time-consuming litigation relating to, among other things, matters that traditionally would have been brought only against the Company or business enterprise itself. The Amended and Restated Certificate of Incorporation of the Company (the "Certificate of Incorporation") and the Amended and Restated Bylaws of the Company (the "Bylaws") require indemnification of the officers and directors of the Company. Indemnitee may also be entitled to indemnification pursuant to the General Corporation Law of the State of Delaware (the "DGCL"). The Bylaws and the DGCL expressly provide that the indemnification provisions set forth therein are not exclusive, and thereby contemplate that contracts may be entered into between the Company and members of the Board, officers and other persons with respect to indemnification;

WHEREAS, the uncertainties relating to such insurance and to indemnification have increased the difficulty of attracting and retaining such persons;

WHEREAS, the Board has determined that the increased difficulty in attracting and retaining such persons is detrimental to the best interests of the Company and its stockholders and that the Company should act to assure such persons that there will be increased certainty of such protection in the future;

WHEREAS, it is reasonable, prudent and necessary for the Company contractually to obligate itself to indemnify, and to advance expenses on behalf of, such persons to the fullest extent permitted by applicable law so that they will serve or continue to serve the Company free from undue concern that they will not be so indemnified;

WHEREAS, this Agreement is a supplement to and in furtherance of the Certificate of Incorporation, the Bylaws and any resolutions adopted pursua thereto, and shall not be deemed a substitute therefor, nor to diminish or abrogate any rights of Indemnitee thereunder; and

WHEREAS, Indemnitee does not regard the protection available under the Certificate of Incorporation, the Bylaws and insurance as adequate in the prese circumstances, and may not be willing to serve or continue to serve as an officer or director without adequate protection, and the Company desires Indemnitee to serve or continue to serve in such capacity. Indemnitee is willing to serve, continue to serve and to take on additional service for or on behalf of the Company on the condition that Indemnitee be so indemnified.

NOW, THEREFORE, in consideration of the premises and the covenants contained herein, the Company and Indemnitee do hereby covenant and agree a follows:

Section 1. Services to the Company. Indemnitee agrees to serve as a **[director] [officer]** of the Company. Indemnitee may at any time and for any reason resign from such position (subject to any other contractual obligation or any obligation imposed by operation of law), in which event the Company shall have no obligation under this Agreement to continue Indemnitee in such position. This Agreement shall not be deemed an employment contract between the Company (or any of its subsidiaries or any Enterprise) and Indemnitee. Indemnitee specifically acknowledges that Indemnitee's employment with the Company (or any of its subsidiaries or any Enterprise), if any, is at will, and the Indemnitee may be discharged at any time for any reason, with or without cause, except as may be otherwise provided in any written employment contract between Indemnitee and the Company (or any of its subsidiaries or any Enterprise), other applicable formal severance policies duly adopted by the Board, or, with respect to service as a director or officer of the Company, by the Certificate of Incorporation, the Bylaws, and the DGCL.The foregoing notwithstanding, this Agreement shall continue in force after Indemnitee has ceased to serve as an **[officer] [director]** of the Company.

Section 2. Definitions. As used in this Agreement:

(a) A "Change in Control" shall be deemed to occur upon the earliest to occur after the date of this Agreement of any of the following events:

i. *Acquisition of Stock by Third Party*. Any Person (as defined below) is or becomes the Beneficial Owner (as defined below), directly or indirectly, of securities of the Company representing [fifteen percent (15%)] or more of the combined voting power of the Company's then outstanding securities; provided, however, 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 combined voting power of the Company inadvertently (including, without limitation, because (A) such Person was unaware that it beneficially owned a percentage of the combined voting power of the Company that would cause a Change of Control or (B) such Person was aware of the extent of its beneficial ownership of the combined voting power of the Company but had no actual knowledge of the consequences of such beneficial ownership under this Agreement) and without any intention of changing or influencing control of the Company, then the beneficial ownership of the combined voting power of the Company by that Person shall not be deemed to be or to have become a Change of Control for any purposes of this Agreement 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 the combined voting power of the Company so that such Person's beneficial ownership of the combined voting power of the Company would no longer otherwise qualify as a Change of Control.

ii. *Change in Board of Directors.* During any period of two (2) consecutive years (not including any period prior to the execution of this Agreement), individuals who at the beginning of such period constitute the Board, and any new director (other than a director designated by a person who has entered into an agreement with the Company to effect a transaction described in Sections 2(b)(i), 2(b)(iii) or 2(b)(iv)) whose election by the Board or nomination for election by the Company's stockholders was approved by a vote of at least two-thirds of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved, cease for any reason to constitute at least a majority of the members of the Board;

iii. *Corporate Transactions.* The effective date of a merger or consolidation of the Company with any other entity, other than a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the Surviving Entity) more than 50% of the combined voting power of the voting securities of the Surviving Entity outstanding immediately after such merger or consolidation and with the power to elect at least a majority of the board of directors or other governing body of such Surviving Entity;

iv. *Liquidation*. The approval by the stockholders of the Company of a complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets; and

v. *Other Events*. There occurs any other event of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A (or a response to any similar item on any similar schedule or form) promulgated under the Exchange Act (as defined below), whether or not the Company is then subject to such reporting requirement.

For purposes of this Section 2(b), the following terms shall have the following meanings:

(A) "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

(B) "Person" shall have the meaning as set forth in Sections 13(d) and 14(d) of the Exchange Act; provided, however, that Person shall exclude (i) the Company, (ii) any trustee or other fiduciary holding securities under an employee benefit plan of the Company, and (iii) any corporation owned, directly or indirectly, by the stockholders of the Company in substantially the same proportions as their ownership of stock of the Company.

(C) "Beneficial Owner" shall have the meaning given to such term in Rule 13d-3 under the Exchange Act; provided, however, that Beneficial Owner shall exclude any Person otherwise becoming a Beneficial Owner by reason of the stockholders of the Company approving a merger of the Company with another entity.

(D) "Surviving Entity" shall mean the surviving entity in a merger or consolidation or any entity that controls, directly or indirectly, such surviving entity.

(b) "Corporate Status" describes the status of a person who is or was a director, officer, employee or agent of the Company or of any other corporation, limited liability company, partnership or joint venture, trust, employee benefit plan or other enterprise which such person is or was serving at the request of the Company.

(c) "Disinterested Director" shall mean a director of the Company who is not and was not a party to the Proceeding in respect of which indemnification is sought by Indemnitee.

(d) "Enterprise" shall mean the Company and any other corporation, limited liability company, partnership, joint venture, trust, employee benefit plan or other enterprise of which Indemnitee is or was serving at the request of the Company as a director, officer or fiduciary.

(e) "Expenses" shall include all reasonable attorneys' fees, retainers, court costs, transcript costs, fees of experts and other professionals, witness fees, travel expenses, duplicating costs, printing and binding costs, telephone charges, postage, delivery service fees, ERISA excise taxes and penalties, and all other disbursements or expenses of the types customarily incurred in connection with prosecuting, defending, preparing to prosecute or defend, investigating, being or preparing to be a witness in, or otherwise participating in, a Proceeding. Expenses also shall include (i) Expenses incurred in connection with any appeal resulting from any Proceeding, including without limitation the premium, security for, and other costs relating to any cost bond, supersedeas bond, or other appeal bond or its equivalent, and (ii) for purposes of Section 14(d) only, Expenses incurred by Indemnitee in connection with the interpretation, enforcement or defense of Indemnitee's rights under this Agreement, by litigation or otherwise. The parties agree that for the purposes of any advancement of Expenses for which Indemnitee has made written demand to the Company in accordance with this Agreement, all Expenses included in such demand that are certified by affidavit of Indemnitee's counsel as being reasonable in the good faith judgment of such counsel shall be presumed conclusively to be reasonable. Expenses, however, shall not include amounts paid in settlement by Indemnitee or the amount of judgments or fines against Indemnitee.

(f) "Independent Counsel" shall mean a law firm, or a member of a law firm, that is experienced in matters of corporation law and neither presently is, nor in the past five years has been, retained to represent: (i) the Company or Indemnitee in any matter material to either such party (other than with respect to matters concerning the Indemnitee under this Agreement, or of other indemnitees under similar indemnification agreements), or (ii) any other party to the Proceeding giving rise to a claim for indemnification hereunder. Notwithstanding the foregoing, the term "Independent Counsel" shall not include any person who, under the applicable standards of professional conduct then prevailing, would have a conflict of interest in representing either the Company or Indemnitee in an action to determine Indemnitee's rights under this Agreement. The Company agrees to pay the reasonable fees and expenses of the Independent Counsel referred to above and to fully indemnify such counsel against any and all Expenses, claims, liabilities and damages arising out of or relating to this Agreement or its engagement pursuant hereto.

(g) The term "Proceeding" shall include any threatened, pending or completed action, suit, claim, counterclaim, cross claim, arbitration, mediation, alternate dispute resolution mechanism, investigation, inquiry, administrative hearing or any other actual, threatened or completed proceeding, whether brought in the right of the Company or otherwise and whether of a civil, criminal, administrative, legislative or investigative (formal or informal) nature, including any appeal therefrom, in which Indemnitee was, is or will be involved as a party, potential party, non-party witness or otherwise by reason of the fact that Indemnitee is or was a director or officer of the Company, by reason of any action taken by Indemnitee (or a failure to take action by Indemnitee) or of any action (or failure to act) on Indemnitee's part while acting pursuant to Indemnitee's Corporate Status, in each case whether or not serving in such capacity at the time any liability or Expense is incurred for which indemnification, reimbursement, or advancement of Expenses can be provided under this Agreement. If the Indemnitee believes in good faith that a given situation may lead to or culminate in the institution of a Proceeding, this shall be considered a Proceeding under this paragraph.

(h) Reference to "other enterprise" shall include employee benefit plans; references to "fines" shall include any excise tax assessed with respect to any employee benefit plan; references to "serving at the request of the Company" shall include any service as a director or officer of the Company which imposes duties on, or involves services by, such director or officer with respect to an employee benefit plan, its participants or beneficiaries; and a person who acted in good faith and in a manner Indemnitee reasonably believed to be in the best interests of the participants and beneficiaries of an employee benefit plan shall be deemed to have acted in a manner "not opposed to the best interests of the Company" as referred to in this Agreement.

Section 3. Indemnity in Third-Party Proceedings. The Company shall indemnify Indemnitee in accordance with the provisions of this Section 3 if Indemnitee is, or is threatened to be made, a party to or a participant in any Proceeding, other than a Proceeding by or in the right of the Company to procure a judgment in its favor, by reason of Indemnitee's Corporate Status. Pursuant to this Section 3, Indemnitee shall be indemnified to the fullest extent permitted by applicable law against all Expenses, judgments, fines and amounts paid in settlement (including all interest, assessments and other charges paid or payable in connection with or in respect of such Expenses, judgments, fines and amounts paid in settlement) actually and reasonably incurred by Indemnitee or on Indemnitee's behalf in connection with such Proceeding or any claim, issue or matter therein, if Indemnitee acted in good faith and in a manner Indemnitee reasonably believed to be in or not opposed to the best interests of the Company and, in the case of a criminal Proceeding had no reasonable cause to believe that Indemnitee's conduct was unlawful. The parties hereto intend that this Agreement shall provide to the fullest extent permitted by law for indemnification in excess of that expressly permitted by statute, including, without limitation, any indemnification provided by the Certificate of Incorporation, the Bylaws, vote of its stockholders or disinterested directors or applicable law.

Section 4. Indemnity in Proceedings by or in the Right of the Company. The Company shall indemnify Indemnitee in accordance with the provisions of this Section 4 if Indemnitee is, or is threatened to be made, a party to or a participant in any Proceeding by or in the right of the Company to procure a judgment in its favor by reason of Indemnitee's Corporate Status. Pursuant to this Section 4, Indemnitee shall be indemnified to the fullest extent permitted by applicable law against all Expenses actually and reasonably incurred by Indemnitee or on Indemnitee's behalf in connection with such Proceeding or any claim, issue or matter therein, if Indemnitee acted in good faith and in a manner Indemnitee reasonably believed to be in or not opposed to the best interests of the Company. No indemnification for Expenses shall be made under this Section 4 in respect of any claim, issue or matter as to which Indemnitee shall have been finally adjudged by a court to be liable to the Company, unless and only to the extent that the Delaware Court (as hereinafter defined) or any court in which the Proceeding was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, Indemnitee is fairly and reasonably entitled to indemnification.

Section 5. Indemnification for Expenses of a Party Who is Wholly or Partly Successful. Notwithstanding any other provisions of this Agreement, to the fullest extent permitted by applicable law and to the extent that Indemnitee is a party to (or a participant in) and is successful, on the merits or otherwise, in any Proceeding or in defense of any claim, issue or matter therein, in whole or in part, the Company shall indemnify Indemnitee against all Expenses actually and reasonably incurred by Indemnitee in connection therewith. If Indemnitee is not wholly successful in such Proceeding but is successful, on the merits or otherwise, as to one or more but less than all claims, issues or matters in such Proceeding, the Company shall indemnify Indemnitee against all Expenses actually and reasonably incurred by Indemnitee or on Indemnitee's behalf in connection with or related to each successfully resolved claim, issue or matter to the fullest extent permitted by law. For purposes of this Section 5 and without limitation, the termination of any claim, issue or matter in such a Proceeding by dismissal, with or without prejudice, shall be deemed to be a successful result as to such claim, issue or matter.

Section 6. Indemnification For Expenses of a Witness. Notwithstanding any other provision of this Agreement, to the fullest extent permitted by applicable law and to the extent that Indemnitee is, by reason of Indemnitee's Corporate Status, a witness or otherwise asked to participate in any Proceeding to which Indemnitee is not a party, Indemnitee shall be indemnified against all Expenses actually and reasonably incurred by Indemnitee or on Indemnitee's behalf in connection therewith.

Section 7. Partial Indemnification. If Indemnitee is entitled under any provision of this Agreement to indemnification by the Company for some or a portion of Expenses, but not, however, for the total amount thereof, the Company shall nevertheless indemnify Indemnitee for the portion thereof to which Indemnitee is entitled.

Section 8. Additional Indemnification.

(a) Notwithstanding any limitation in Section 3, Section 4, or Section 5, the Company shall indemnify Indemnitee to the fullest extent permitted by applicable law if

Indemnitee is a party to or threatened to be made a party to any Proceeding (including a Proceeding by or in the right of the Company to procure a judgment in its favor) by reason of Indemnitee's Corporate Status.

(b) For purposes of Section 8(a), the meaning of the phrase "to the fullest extent permitted by applicable law" shall include, but not be limited to:

i.

ii. to the fullest extent permitted by the provision of the DGCL that authorizes or contemplates additional indemnification by agreement, or the corresponding provision of any amendment to or replacement of the DGCL, and

iii.

iv.

v. to the fullest extent authorized or permitted by any amendments to or replacements of the DGCL adopted after the date of this Agreement that increase the extent to which a corporation may indemnify its officers and directors.

Section 9. Exclusions. Notwithstanding any provision in this Agreement, the Company shall not be obligated under this Agreement to make any indemnification payment in connection with any claim involving Indemnitee:

(a) for which payment has actually been made to or on behalf of Indemnitee under any insurance policy or other indemnity provision, except with respect to any excess beyond the amount paid under any insurance policy or other indemnity provision; or

(b) for (i) an accounting of profits made from the purchase and sale (or sale and purchase) by Indemnitee of securities of the Company within the meaning of Section 16(b) of the Exchange Act or similar provisions of state statutory law or common law, or (ii) any reimbursement of the Company by the Indemnitee of any bonus or other incentive-based or equity-based compensation or of any profits realized by the Indemnitee from the sale of securities of the Company, as required in each case under the Exchange Act (including any such reimbursements that arise from an accounting restatement of the Company pursuant to Section 304 of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), or the payment to the Company of profits arising from the purchase and sale by Indemnitee of securities in violation of Section 306 of the Sarbanes-Oxley Act) or (iii) any reimbursement of the Company by Indemnitee of any compensation pursuant to any compensation recoupment or clawback policy adopted by the Board or the compensation committee of the Board, including but not limited to any such policy adopted to comply with stock exchange listing requirements implementing Section 10D of the Exchange Act; or

(c) except as provided in Section 14(d) of this Agreement, in connection with any Proceeding (or any part of any Proceeding) initiated by Indemnitee, including any Proceeding (or any part of any Proceeding) initiated by Indemnitee against the Company or its directors, officers, employees or other indemnitees, unless (i) the Board authorized the Proceeding (or any part of any Proceeding) prior to its initiation or (ii) the Company provides the indemnification, in its sole discretion, pursuant to the powers vested in the Company under applicable law.

Section 10. Advancement of Expenses. Notwithstanding any provision of this Agreement to the contrary (other than Section 14(d)), the Company shall advance, to the extent not prohibited by law, the Expenses incurred by Indemnitee in connection with any Proceeding (or any part of any Proceeding) not initiated by Indemnitee or any Proceeding initiated by Indemnitee with the prior approval of the Board as provided in Section 9(c), and such advancement shall be made within thirty (30) days after the receipt by the Company of a statement or statements requesting such advances from time to time, whether prior to or after final disposition of any Proceeding. Advances shall be unsecured and interest free. Advances shall be made without regard to Indemnitee's ability to repay the Expenses and without regard to Indemnitee's ultimate entitlement to indemnification under the other provisions of this Agreement. In accordance with Section 14(d), advances shall include any and all reasonable Expenses incurred pursuing an action to enforce this right of advancement, including Expenses incurred preparing and forwarding statements to the Company to support the advances claimed. The Indemnitee shall qualify for advances upon the execution and delivery to the Company of this Agreement, which shall constitute an undertaking providing that the Indemnitee undertakes to repay the amounts advanced (without interest) to the extent that it is ultimately determined that Indemnitee is not entitled to be indemnified by the Company. No other form of undertaking shall be required other than the execution of this Agreement. This Section 10 shall not apply to any claim made by Indemnitee for which indemnity is excluded pursuant to Section 9.

Section 11. Procedure for Notification and Defense of Claim.

(a) Indemnitee shall notify the Company in writing of any matter with respect to which Indemnitee intends to seek indemnification or advancement of Expenses hereunder as soon as reasonably practicable following the receipt by Indemnitee of written notice thereof. The written notification to the Company shall include a description of the nature of the Proceeding and the facts underlying the Proceeding. To obtain indemnification under this Agreement, Indemnitee shall submit to the Company a written request, including therein or therewith such documentation and information as is reasonably available to Indemnitee and is reasonably necessary to determine whether and to what extent Indemnitee is entitled to indemnification following the final disposition of such Proceeding. The omission by Indemnitee to notify the Company hereunder will not relieve the Company from any liability which it may have to Indemnitee hereunder or otherwise than under this Agreement, and any delay in so notifying the Company shall not constitute a waiver by Indemnitee of any rights under this Agreement. The Secretary of the Company shall, promptly upon receipt of such a request for indemnification, advise the Board in writing that Indemnitee has requested indemnification.

(b) The Company will be entitled to participate in the Proceeding at its own expense.

Section 12. Procedure Upon Application for Indemnification.

(a) Upon written request by Indemnitee for indemnification pursuant to Section 11(a), a determination, if required by applicable law, with respect to Indemnitee's entitlement thereto shall be made in the specific case: (i) if a Change in Control shall have occurred, by Independent Counsel in a written opinion to the Board, a copy of which shall be delivered to Indemnitee; or (ii) if a Change in Control shall not have occurred, (A) by a majority vote of the Disinterested Directors, even though less than a quorum of the Board, (B) by a committee of Disinterested Directors designated by a majority vote of the Disinterested Directors, even though less than a quorum of the Board, (C) if there are no such Disinterested

Directors or, if such Disinterested Directors so direct, by Independent Counsel in a written opinion to the Board, a copy of which shall be delivered to Indemnitee o (D) if so directed by the Board, by the stockholders of the Company; and, if it is so determined that Indemnitee is entitled to indemnification, payment to Indemnite shall be made within ten (10) days after such determination. Indemnitee shall cooperate with the person, persons or entity making such determination with respect to Indemnitee's entitlement to indemnification, including providing to such person, persons or entity upon reasonable advance request any documentation or information which is not privileged or otherwise protected from disclosure and which is reasonably available to Indemnitee and reasonably necessary to such determination. Any costs or Expenses (including attorneys' fees and disbursements) incurred by Indemnitee in so cooperating with the person, persons or entity making such determination shall be borne by the Company (irrespective of the determination as to Indemnitee's entitlement to indemnification) and the Company hereby indemnifies and agrees to hold Indemnitee harmless therefrom. The Company promptly will advise Indemnitee in writing with respect to any determination that Indemnitee is or is not entitled t indemnification, including a description of any reason or basis for which indemnification has been denied.

(b) In the event the determination of entitlement to indemnification is to be made by Independent Counsel pursuant to Section 12(a) hereof, the Independent Counsel shall be selected as provided in this Section 12(b). If a Change in Control shall not have occurred, the Independent Counsel shall be selected b the Board, and the Company shall give written notice to Indemnitee advising Indemnitee of the identity of the Independent Counsel so selected.If a Change in Contro shall have occurred, the Independent Counsel shall be selected by Indemnitee (unless Indemnitee shall request that such selection be made by the Board, in whicl event the preceding sentence shall apply), and Indemnitee shall give written notice to the Company advising it of the identity of the Independent Counsel so selected In either event, Indemnitee or the Company, as the case may be, may, within ten (10) days after such written notice of selection shall have been given, deliver to the Company or to Indemnitee, as the case may be, a written objection to such selection; provided, however, that such objection may be asserted only on the ground that the Independent Counsel so selected does not meet the requirements of Independent Counsel, and the objection shall set forth with particularity the factual basis o such assertion. Absent a proper and timely objection, the person so selected shall act as Independent Counsel. If such written objection is so made and substantiated, the Independent Counsel so selected may not serve as Independent Counsel unless and until such objection is withdrawn or the Delaware Court has determined tha such objection is without merit. If, within twenty (20) days after the later of submission by Indemnitee of a written request for indemnification pursuant to Section 11(a) hereof and the final disposition of the Proceeding, no Independent Counsel shall have been selected and not objected to, either the Company or Indemnitee ma petition the Delaware Court for resolution of any objection which shall have been made by the Company or Indemnitee to the other's selection of Independent Counsel and/or for the appointment as Independent Counsel of a person selected by the Court or by such other person as the Court shall designate, and the person with respec to whom all objections are so resolved or the person so appointed shall act as Independent Counsel under Section 12(a) hereof. Upon the due commencement of any judicial proceeding or arbitration pursuant to Section 14(a) of this Agreement, Independent Counsel shall be discharged and relieved of any further responsibility ir such capacity (subject to the applicable standards of professional conduct then prevailing).

Section 13. Presumptions and Effect of Certain Proceedings.

(a) In making a determination with respect to entitlement to indemnification hereunder, the person or persons or entity making such determination shall, to the fullest extent not prohibited by law, presume that Indemnitee is entitled to indemnification under this Agreement if Indemnitee has submitted a request for indemnification in accordance with Section 11(a) of this Agreement, and the Company shall, to the fullest extent not prohibited by law, have the burden of proof to overcome that presumption in connection with the making by any person, persons or entity of any determination contrary to that presumption. Neither the failure of the Company (including by its directors or Independent Counsel) to have made a determination prior to the commencement of any action pursuant to this Agreement that indemnification is proper in the circumstances because Indemnitee has met the applicable standard of conduct, nor an actual determination by the Company (including by its directors or Independent Counsel) that Indemnitee has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that Indemnitee has not met the applicable standard of conduct.

(b) Subject to Section 14(e), if the person, persons or entity empowered or selected under Section 12 of this Agreement to determine whether Indemnitee is entitled to indemnification shall not have made a determination within sixty (60) days after receipt by the Company of the request therefor, the requisite determination of entitlement to indemnification shall, to the fullest extent not prohibited by law, be deemed to have been made and Indemnitee shall be entitled to such indemnification, absent (i) a misstatement by Indemnitee of a material fact, or an omission of a material fact necessary to make Indemnitee's statement not materially misleading, in connection with the request for indemnification, or (ii) a prohibition of such indemnification under applicable law; provided, however, that such 60-day period may be extended for a reasonable time, not to exceed an additional thirty (30) days, if the person, persons or entity making the determination with respect to entitlement to indemnification in good faith requires such additional time for the obtaining or evaluating of documentation and/or information relating thereto; and provided, further, that the foregoing provisions of this Section 13(b) shall not apply (i) if the determination of entitlement to indemnification is to be made by the stockholders pursuant to Section 12(a) of this Agreement and if (A) within fifteen (15) days after receipt by the Company of the request for such determination the Board has resolved to submit such determination to the stockholders for their consideration at an annual meeting thereof to be held within seventy-five (75) days after such receipt and such determination is made thereat, or (B) a special meeting of stockholders is called within fifteen (15) days after such receipt for the purpose of making such determination, such meeting is held for such purpose within sixty (60) days after having been so called and such determination is made thereat, or (ii) if the determination of entitlement to indemnification is to be made by Independent Counsel pursuant to Section 12(a) of this Agreement.

(c) The termination of any Proceeding or of any claim, issue or matter therein, by judgment, order, settlement or conviction, or upon a plea of nolo contendere or its equivalent, shall not (except as otherwise expressly provided in this Agreement) of itself adversely affect the right of Indemnitee to indemnification or create a presumption that Indemnitee did not act in good faith and in a manner which Indemnitee reasonably believed to be in or not opposed to the best interests of the Company or, with respect to any criminal Proceeding, that Indemnitee had reasonable cause to believe that Indemnitee's conduct was unlawful.

(d) For purposes of any determination of good faith, Indemnitee shall be deemed to have acted in good faith if Indemnitee's action is based on the records or books of account of the Enterprise, including financial statements, or on information supplied to Indemnitee by the directors or officers of the Enterprise in the course of their duties, or on the advice of legal counsel for the Enterprise or on information or records given or reports made to the Enterprise by an independent certified public accountant or by an appraiser, financial advisor or other expert selected with reasonable care by or on behalf of the Enterprise. The provisions of this Section 13(d) shall not be deemed to be exclusive or to limit in any way the other circumstances in which the Indemnitee may be deemed to have met the applicable standard of conduct set forth in this Agreement.

(e) The knowledge and/or actions, or failure to act, of any director, officer, trustee, partner, managing member, fiduciary, agent or employee of the Enterprise shall not be imputed to Indemnitee for purposes of determining the right to indemnification under this Agreement.

Section 14. Remedies of Indemnitee.

(a) Subject to Section 14(e), in the event that (i) a determination is made pursuant to Section 12 of this Agreement that Indemnitee is not entitled to indemnification under this Agreement, (ii) advancement of Expenses is not timely made pursuant to Section 10 of this Agreement, (iii) no determination of entitlement to indemnification shall have been made pursuant to Section 12(a) of this Agreement within ninety (90) days after receipt by the Company of the request for indemnification, (iv) payment of indemnification is not made pursuant to Section 5, 6 or 7 or the second to last sentence of Section 12(a) of this Agreement within ten (10) days after receipt by the Company of a written request therefor, (v) payment of indemnification pursuant to Section 3, 4 or 8 of this Agreement is not made within ten (10) days after a determination has been made that Indemnitee is entitled to indemnification, or (vi) in the event that the Company or any other person takes or threatens to take any action to declare this Agreement void or unenforceable, or institutes any litigation or other action or Proceeding designed to deny, or to recover from, the Indemnitee the benefits provided or intended to be provided to the Indemnitee hereunder, Indemnitee shall be entitled to an adjudication by a court of Indemnitee's entitlement to such indemnification or advancement of Expenses. Alternatively, Indemnitee, at Indemnitee's option, may seek an award in arbitration to be conducted by a single arbitrator pursuant to the Commercial Arbitration Rules of the American Arbitration Association. Indemnitee shall commence such proceeding seeking an adjudication or an award in arbitration within one hundred eighty (180) days following the date on which Indemnitee first has the right to commence such proceeding pursuant to this Section 14(a). The Company shall not oppose Indemnitee's right to seek any such adjudication or award in arbitration.

(b) In the event that a determination shall have been made pursuant to Section 12(a) of this Agreement that Indemnitee is not entitled to indemnification, any judicial proceeding or arbitration commenced pursuant to this Section 14 shall be conducted in all respects as a de novo trial, or arbitration, on the merits and Indemnitee shall not be prejudiced by reason of that adverse determination. In any judicial proceeding or arbitration commenced pursuant to this Section 14 the Company shall have the burden of proving Indemnitee is not entitled to indemnification or advancement of Expenses, as the case may be.

(c) If a determination shall have been made pursuant to Section 12(a) of this Agreement that Indemnitee is entitled to indemnification, the Company shall be bound by such determination in any judicial proceeding or arbitration commenced pursuant to this Section 14, absent (i) a misstatement by Indemnitee of a material fact, or an omission of a material fact necessary to make Indemnitee's statement not materially misleading, in connection with the request for indemnification, or (ii) a prohibition of such indemnification under applicable law.

(d) The Company shall, to the fullest extent not prohibited by law, be precluded from asserting in any judicial proceeding or arbitration commenced pursuant to this Section 14 that the procedures and presumptions of this Agreement are not valid, binding and enforceable and shall stipulate in any such court or before any such arbitrator that the Company is bound by all the provisions of this Agreement. It is the intent of the Company that, to the fullest extent permitted by law, the Indemnitee not be required to incur legal fees or other Expenses associated with the interpretation, enforcement or defense of Indemnitee's rights under this Agreement by litigation or otherwise because the cost and expense thereof would substantially detract from the benefits intended to be extended to the Indemnitee hereunder. The Company shall, to the fullest extent permitted by law, indemnify Indemnitee against any and all Expenses and, if requested by Indemnitee, shall (within ten (10) days after receipt by the Company of a written request therefor) advance, to the extent not prohibited by law, such Expenses to Indemnitee, which are incurred by Indemnitee in connection with any action brought by Indemnitee for indemnification or advancement of Expenses from the Company under this Agreement or under any directors' and officers' liability insurance policies maintained by the Company if in the case of indemnification, Indemnitee is wholly successful on the underlying claims; if Indemnitee is not wholly successful on the underlying claims, then such indemnification shall be only to the extent Indemnitee is successful on such underlying claims or otherwise as permitted by law, whichever is greater.

(e) Notwithstanding anything in this Agreement to the contrary, no determination as to entitlement of Indemnitee to indemnification under this Agreement shall be required to be made prior to the final disposition of the Proceeding.

Section 15. Non-exclusivity; Survival of Rights; Insurance; Subrogation.

(a) The rights of indemnification and to receive advancement of Expenses as provided by this Agreement shall not be deemed exclusive of any other rights to which Indemnitee may at any time be entitled under applicable law, the Certificate of Incorporation, the Bylaws, any agreement, a vote of stockholders or a resolution of directors, or otherwise. No amendment, alteration or repeal of this Agreement or of any provision hereof shall limit or restrict any right of Indemnitee under this Agreement in respect of any action taken or omitted by Indemnitee in Indemnitee's Corporate Status prior to such amendment, alteration or repeal. To the extent that a change in Delaware law, whether by statute or judicial decision, permits greater indemnification or advancement of Expenses than would be afforded currently under the Certificate of Incorporation, Bylaws and this Agreement, it is the intent of the parties hereto that Indemnitee shall enjoy by this Agreement the greater benefits so afforded by such change. No right or remedy herein conferred is intended to be exclusive of any other right or remedy, and every other right and remedy shall be cumulative and in addition to every other right and remedy given hereunder or now or hereafter existing at law or in equity or otherwise. The assertion or employment of any right or remedy hereunder, or otherwise, shall not prevent the concurrent assertion or employment of any other right or remedy.

(b) To the extent that the Company maintains an insurance policy or policies providing liability insurance for directors, officers, employees, or agents of the Enterprise, Indemnitee shall be covered by such policy or policies in accordance with its or their terms to the maximum extent of the coverage available for any such director, officer, employee or agent under such policy or policies. If, at the time of the receipt of a notice of a claim pursuant to the terms hereof, the Company has director and officer liability insurance in effect, the Company shall give prompt notice of such claim or of the commencement of a Proceeding, as the case may be, to the insurers in accordance with the procedures set forth in the respective policies. The Company shall thereafter take all necessary or desirable action to cause such insurers to pay, on behalf of the Indemnitee, all amounts payable as a result of such Proceeding in accordance with the terms of such policies.

(c) In the event of any payment made by the Company under this Agreement, the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Indemnitee, who shall execute all papers required and take all action necessary to secure such rights, including execution of such documents as are necessary to enable the Company to bring suit to enforce such rights.

(d) The Company shall not be liable under this Agreement to make any payment of amounts otherwise indemnifiable (or for which advancement is provided hereunder) hereunder if and to the extent that Indemnitee has otherwise actually received such payment under any insurance policy, contract, agreement or otherwise.

(e) The Company's obligation to indemnify or advance Expenses hereunder to Indemnitee who is or was serving at the request of the Company as a director, officer, trustee, partner, managing member, fiduciary, employee or agent of any other corporation, limited liability company, partnership, joint venture, trust, employee benefit plan or other enterprise shall be reduced by any amount Indemnitee has actually received as indemnification or advancement of Expenses from such other corporation, limited liability company, partnership, joint venture, trust, employee benefit plan or other enterprise.

Section 16. Duration of Agreement. This Agreement shall continue until and terminate upon the later of: (a) ten (10) years after the date that Indemnitee shall have ceased to serve as a **[director] [officer]** of the Company, or (b) one (1) year after the final termination of any Proceeding then pending in respect of which Indemnitee is granted rights of indemnification or advancement of Expenses hereunder and of any proceeding commenced by Indemnitee pursuant to Section 14 of this Agreement relating thereto. The indemnification and advancement of expenses rights provided by or granted pursuant to this Agreement shall be binding upon and be enforceable by the parties hereto and their respective successors and assigns (including any direct or indirect successor by purchase, merger, consolidation or otherwise to all or substantially all of the business or assets of the Company), shall continue as to an Indemnitee who has ceased to be a director or officer of the Company or of any other Enterprise, and shall inure to the benefit of Indemnitee and Indemnitee's spouse, assigns, heirs, devisees, executors and administrators and other legal representatives.

Section 17. Severability. If any provision or provisions of this Agreement shall be held to be invalid, illegal or unenforceable for any reason whatsoever: (a) the validity, legality and enforceability of the remaining provisions of this Agreement (including without limitation, each portion of any Section of this Agreement containing any such provision held to be invalid, illegal or unenforceable, that is not itself invalid, illegal or unenforceable) shall not in any way be affected or impaired thereby and shall remain enforceable to the fullest extent permitted by law; (b) such provision or provisions shall be deemed reformed to the extent necessary to conform to applicable law and to give the maximum effect to the intent of the parties hereto; and (c) to the fullest extent possible, the provisions of this Agreement (including, without limitation, each portion of any Section of this Agreement containing any such provision held to be invalid, illegal or unenforceable, that is not itself invalid, illegal or unenforceable) shall be construed so as to give effect to the intent manifested thereby.

Section 18. Enforcement.

(a) The Company expressly confirms and agrees that it has entered into this Agreement and assumed the obligations imposed on it hereby in order to induce Indemnitee to serve as a director or officer of the Company, and the Company acknowledges that Indemnitee is relying upon this Agreement in serving or continuing to serve as a director or officer of the Company.

(b) This Agreement constitutes the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes all prior agreements and understandings, oral, written and implied, between the parties hereto with respect to the subject matter hereof; provided, however, that this Agreement is a supplement to and in furtherance of the Certificate of Incorporation, the Bylaws and applicable law, and shall not be deemed a substitute therefor, nor to diminish or abrogate any rights of Indemnitee thereunder.

Section 19. Modification and Waiver. No supplement, modification or amendment of this Agreement shall be binding unless executed in writing by the parties hereto. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provisions of this Agreement nor shall any waiver constitute a continuing waiver.

Section 20. Notice by Indemnitee. Indemnitee agrees promptly to notify the Company in writing upon being served with any summons, citation, subpoena, complaint, indictment, information or other document relating to any Proceeding or matter which may be subject to indemnification or advancement of Expenses covered hereunder. The failure of Indemnitee to so notify the Company shall not relieve the Company of any obligation which it may have to the Indemnitee under this Agreement or otherwise.

Section 21. Notices. All notices, requests, demands and other communications under this Agreement shall be in writing and shall be deemed to have been duly given if (a) delivered by hand and receipted for by the party to whom said notice or other communication shall have been directed, (b) mailed by certified or registered mail with postage prepaid, on the third (3) business day after the date on which it is so mailed, or (c) mailed by reputable overnight courier and receipted for by the party to whom said notice or other communication shall have been directed:

(a) If to Indemnitee, at the address indicated on the signature page of this Agreement, or such other address as Indemnitee shall provide to the Company.

(b) If to the Company to

Unit Corporation
8200 South Unit Drive
Tulsa, Oklahoma 74132
Attention: General Counsel

or to any other address as may have been furnished to Indemnitee by the Company.

Section 22. Contribution. To the fullest extent permissible under applicable law, if the indemnification provided for in this Agreement is unavailable to Indemnitee for any reason whatsoever, the Company, in lieu of indemnifying Indemnitee, shall contribute to the amount incurred by Indemnitee, whether for judgments, fines, penalties, excise taxes, amounts paid or to be paid in settlement and/or for Expenses, in connection with any claim relating to an indemnifiable event under this Agreement, in such proportion as is deemed fair and reasonable in light of all of the circumstances of such Proceeding in order to reflect (i) the relative benefits received by the Company and Indemnitee as a result of the event(s) and/or transaction(s) giving cause to such Proceeding; and/or (ii) the relative fault of the Company (and its directors, officers, employees and agents) and Indemnitee in connection with such event(s) and/or transaction(s).

Section 23. Applicable Law and Consent to Jurisdiction. This Agreement and the legal relations among the parties shall be governed by, and construed and enforced in accordance with, the laws of the State of Delaware, without regard to its conflict of laws rules. Except with respect to any arbitration commenced by Indemnitee pursuant to Section 14(a) of this Agreement, the Company and Indemnitee hereby irrevocably and unconditionally (i) agree that any action or proceeding arising out of or in connection with this Agreement shall be brought only in the Court of Chancery of the State of Delaware (the "Delaware Court"), and not in any other state or federal court in the United States of America or any court in any other country, (ii) consent to submit to the exclusive jurisdiction of the Delaware Court for purposes of any action or proceeding arising out of or in connection with this Agreement, (iii) appoint, to the extent such party is not otherwise subject to service of process in the State of Delaware, irrevocably RL&F Service Corp., 920 North King Street, 2nd Floor, Wilmington, New Castle County, Delaware 19801 as its agent in the State of Delaware as such party's agent for acceptance of legal process in connection with any such action or proceeding against such party with the same legal force and validity as if served upon such party personally within the State of Delaware, (iv) waive any objection to the laying of venue of any such action or proceeding in the Delaware Court, and (v) waive, and agree not to plead or to make, any claim that any such action or proceeding brought in the Delaware Court has been brought in an improper or inconvenient forum.

Section 24. Identical Counterparts. This Agreement may be executed in one or more counterparts, each of which shall for all purposes be deemed to be an original but all of which together shall constitute one and the same Agreement. Only one such counterpart signed by the party against whom enforceability is sought needs to be produced to evidence the existence of this Agreement.

Section 25. Miscellaneous. Use of the masculine pronoun shall be deemed to include usage of the feminine pronoun where appropriate. The headings of this Agreement are inserted for convenience only and shall not be deemed to constitute part of this Agreement or to affect the construction thereof

[*Remainder of page intentionally left blank. Signature pages follow.*]

IN WITNESS WHEREOF, the parties have caused this Agreement to be signed as of the day and year first above written.

COMPANY:

UNIT CORPORATION

By:_Name:

Title:

INDEMNITEE:

By: Name:
Title:

Address:

[Signature Page to Indemnification Agreement]

September [ ], 2020

[Name]
Sent via e-mail

RE: Offer of Engagement as Board Member

Dear [ ]:

We are pleased to offer you to join the Board of Directors (the "Board") of Unit Corporation (the "Company"). The purpose of this letter agreement is to confirm the terms and arrangements related to your service as a member of the Board.

1. **Service**. You will serve as a member of the Board until a successor is duly elected or appointed, or until your earlier resignation, removal, death, or incapacity, in each case in accordance with applicable law and the organizational documents of the Company.

2. **Retainer Fees**.

   a. The Company will pay you an annual cash retainer fee for your services as a member of the Board at the rate of $65,000 per year as long as you serve as a member of the Board (the "Fee"), such amount to be paid in equal quarterly installments during the first payroll period following the end of each of the Company's fiscal quarters (with proration for any partial period of service).

   a. The Company will pay you an additional annual cash retainer fee for each committee on which you serve as a member at the rate of $10,000 per year as long as you serve as a member of such committee (the "Committee Fee"), such amount to be paid in equal quarterly installments during the first payroll period following the end of each of the Company's fiscal quarters (with proration for any partial period of service).

3. **Chairman Fees**. In the event you are elected to serve as the chairman of the Board (the "Chairman of the Board"), the Company will pay you an annual cash retainer fee for your services as the Chairman of the Board at the rate of $15,000 per year as long as you serve as Chairman of the Board (the "Chairman Fee"), such amount to be paid in equal quarterly installments during the first payroll period following the end of each of the Company's fiscal quarters (with proration for any partial period of service).

4. **Option Award**. As soon as reasonably practicable after the date in which you begin service as a member of the Board (the "Effective Date"), the Company will grant you 16,739.00 of options of the Company with a strike price of USD $15.52 based on an equity value of $158,600,000 (the "Options") as of the date of grant. The Options will be subject to the terms and conditions of a management incentive plan (the "MEIP") to be implemented after the Company's exit from bankruptcy and will be granted pursuant to a separate award agreement (the "Award Agreement"), which shall set forth that the Options will vest in four equal tranches with twenty-five percent vesting on each of the first four anniversaries of the Effective Date. Copies of the MEIP and the Award Agreement are attached to this letter agreement.

5. **Expenses**. The Company will reimburse you for your reasonable out of pocket expenses incurred in the performance of your services as a member of the Board, including travel and lodging expenses related to your attendance at meetings, provided you submit receipts or other documentation reasonably acceptable to the Company in accordance with the Company's reimbursement policies.

6. **Independent Contractor Relationship**. This letter agreement and your appointment to the Board does not create or otherwise establish any right on your part to be or to continue to be elected or appointed to the Board and does not create an employment contract or employment arrangement between the Company and you. Your services are as an independent contractor, and this letter agreement shall not entitle you to receive from the Company any employee benefits or reimbursements with respect thereto. By acceptance of this offer, you acknowledge that you

will receive an IRS Form 1099 from the Company, that you will be solely responsible for timely payment of applicable taxes due in connection with all payments set forth herein and that the Company has given you no tax advice as to the treatment of such payments.

7. **Indemnification**. You shall be indemnified by the Company for actions or inactions in your role as a member of the Board in accordance with (i) the Company's organizational documents, a copy of which will be provided to you under separate cover and (ii) the Company's indemnification agreement attached to this letter agreement, upon execution by all parties thereto.

8. **Governing Law**. This letter agreement and any claim or controversy arising hereunder or related hereto (whether by contract, tort or otherwise) will be governed by and construed in accordance with the laws of the State of Delaware applicable to contracts made and to be performed in such jurisdiction without giving effect to the principles of conflicts of law.

9. **Miscellaneous**. By accepting the offer to serve as a member of the Board, you represent that you are not bound by or otherwise subject to any agreement or other instrument that would prohibit, limit or otherwise restrict your ability to discharge your duties and obligations as a member of the Board.

Please confirm your acceptance and agreement to the terms described herein by signing on the space provided below and returning this letter agreement to the Company. We believe your skills and experience will play a significant role in the future success of the Company and look forward to your joining the Board.

UNIT CORPORATION

By:
Name:
Title:

Agreed and Accepted as of the date first written above.

____
[Director Name]

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, 2020 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 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the filing of our reserves audit report dated February 9, 2021, as Exhibit 23.2 to the Unit Corporation annual report on Form 10-K for the year ended December 31, 2020 and to any reference made to us on that form 10-K.

/s/ RYDER SCOTT COMPANY, L.P.

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

Houston, Texas
March 31, 2021

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, 2021

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

<u>**Exhibit 31.2**</u>

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, 2021

<u>/s/ Thomas D. Sell</u>
THOMAS D. SELL
Interim Chief Financial Officer

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, 2020 (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, 2020 and December 31, 2019 and for the Successor and Predecessor Periods of December 31, 2020 and year ended December 31, 2019.

Dated: March 31, 2021

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

Dated: March 31, 2021

By: /s/ Thomas D. Sell
Thomas D. Sell
Interim 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-Q 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 Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2020

\s\ Robert J. Paradiso

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

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE 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 9, 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 revised reserves audit of the estimates o the proved reserves as of December 31, 2020 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 2, 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, 2020. The properties reviewed by Ryder Scott incorporate 249 reserves determinations and are located in the states of Kansas, 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, 2020. Based on the estimates of total net proved reserves prepared by Unit, the reserves audit conducted by Ryder Scott addresses 79 percent of the total proved developed net liquid hydrocarbon reserves and 66 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, 2020. Unit informed Ryder Scott that the selected entities included approximately 85% of Unit's discounted future net income at 10% for the total proved developed reserves, which is also 85% 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 and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Unit, it is our opinion that the overall procedures and methodologies utilized by Unit in preparing their estimates of the proved reserves as of December 31, 2020 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, 2020, 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, 2020

	Total Proved Developed Producing
Net Reserves of Properties Audited by Ryder Scott	
Oil/Condensate – MBarrels	7,028
Plant Products – MBarrels	11,471
Gas - MMcf	95,460
Net Reserves of Properties Not Audited by Ryder Scott	
Oil/Condensate – MBarrels	1,239
Plant Products – MBarrels	3,737
Gas - MMcf	48,931
Total Net Reserves	
Oil/Condensate – MBarrels	8,267
Plant Products – MBarrels	15,208
Gas - MMcf	144,391

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 increas 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 96 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 October 2020, 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 4 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, 2020 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	$39.57/Bbl	$37.31/Bbl
	NGLs	Mont Belvieu Non TET Propane	$18.74/Bbl	$10.97/Bbl
	Gas	Henry Hub	$1.99/MMBTU	$1.56/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, 2020 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 21 percent of the total proved net liquid hydrocarbon reserves and 34 percent of the total proved net gas reserves based on estimates prepared by Unit as of December 31, 2020.

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.
TBPE Firm Registration No. F-1580

/s/ Robert J. Paradiso

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

[SEAL]

RJP (FWZ)/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 an Gas, Inc., Norcen Explorer, Inc., Amerac Energy Corporation, Halliburton Energy Services, Santa Fe Snyder Corp., and Devon Energy Corporation. For more information regarding Mr. Paradiso's geographic and job specific experience, please refer to the Ryder Scott Company website a https://ryderscott.com/employees/houston-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 2020 continuing education hours, Mr. Paradiso attended 6½ hours of formalized training during the 2020 RSC Reserves Conference relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Paradiso attended an additional 83 hours of formalized in-house training during 2020 covering such topics as Greenhouse Gas Reporting, the SPE/WPC/AAPG/SPEE Petroleum Resourc Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 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 set forth in Article III of th "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, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

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

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

RESERVES (SEC DEFINITIONS)

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

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

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

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 tc 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.