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, 2019

OR

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

For the transition period from to

Commission file number: 1-9260

UNIT CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $.20 per share	UNT	NYSE

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 ☐ No X

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 X No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

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 X Non-accelerated filer ☐

Smaller reporting company ☐ Emerging growth company ☐

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

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

As of June 28, 2019, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the NYSE on June 28, 2019) held by non-affiliates was approximately $467,332,169. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.

As of February 28, 2020, 55,423,610 shares of the issuer's common stock were outstanding.

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 140

FORM 10-K
UNIT CORPORATION

TABLE OF CONTENTS

The following are explanations of some terms used 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 proved 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.

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.

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.

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

Mcf – Thousand cubic feet of natural gas.

Mcfe – Thousand 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.

MMBbls – Million barrels of crude oil or other liquid hydrocarbons.

MMBoe – Million 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.

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.

SARs – Stock appreciation rights.

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.

UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2019

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 practicable after we electronically file these reports with or furnish them to the Securities and Exchange Commission (SEC). The SEC maintains an Internet website at *www.sec.gov* that contains reports, proxy and information statements, and other information about us that 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, and the charters of our Board's Audit, Compensation, and Nominating and Governance Committees, 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 our subsidiary Superior Pipeline Company, L.L.C., and its subsidiaries (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.

This table provides certain information about us as of February 28, 2020:

Oil and Natural Gas	
Total number of wells in which we own an interest	6,151
Contract Drilling	
Total number of drilling rigs available for use	58
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	19

2019 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

- Increased oil production by 11.6% over 2018 while total equivalent production decreased 1.4% with the hold on drilling program in the second half of the year.
- Initiated development drilling program of Red Fork horizontal play with outstanding results.
- Cost cuts identified during the fourth quarter of 2019 expected to reduce lease operating expense by 10.0% during 2020.
- Sold non-core assets with proceeds of $21.8 million.

Contract Drilling

- Utilization cycle during 2019:
  - Began the year with 32 drilling rigs operating;
  - Placed two new BOSS drilling rigs into service in the first quarter and one new BOSS drilling rig in the fourth quarter; and
  - Averaged rig utilization between 30-32 drilling rigs operating through the middle of May 2019, as many operators front end loaded their drilling budgets in the first half of 2019. Utilization decreased to 18 drilling rigs at the end of August and remained at that level into early December finishing out the year at 20 drilling rigs operating.
- All 14 BOSS drilling rigs were operating when placed in service during the year.
- Average drilling rig dayrates increased 7.2% during the year primarily due to higher BOSS drilling rig concentration in drilling rigs operating.

Mid-Stream

- Completed the acquisition of Central Oklahoma assets consisting of 572 miles of pipeline and related compressor stations in December 2019.
- Increased average throughput volume to 436 MMcf per day during 2019, a 10.7% increase over 2018.
- Increased average processed gas volumes to 164 MMcf per day during 2019, a 4.0% increase over 2018.
- During 2019 connected a total of 69 new wells to our gathering and processing systems from various producers.
- Connected seven new wells to the Pittsburgh Mills gathering system from a new well pad which increased gathered volume approximately 95 MMcf per day.
- Connected 35 new wells to the Cashion system during 2019 from active producers with significant acreage dedications.
- Completed the installation of a new 60 MMcf per day processing plant that was transferred from Bellmon at the Reeding location on the Cashion gathering system which increased our total processing capacity on the Cashion system to 105 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 regarding 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, Texas, and to a lesser extent Arkansas, Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Utah, and Wyoming.

When we are the operator of a property, we try to drill wells using a drilling rig owned by our contract drilling segment, and we 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, 2019:

	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2019 Average Net Daily Production		
					Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
Total	6,149	2,207.63	21	1.21	145,383	8,788	13,077

As of December 31, 2019, we had no significant water floods, pressure maintenance operations, or any other material related activities in process.

Acquisitions. On April 3, 2017, we closed an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million. As of January 1, 2017, the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. This acquisition included 13 potential horizontal drilling locations not otherwise included in our existing acreage. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

In December 2018, we closed on an acquisition of certain oil and natural gas assets located primarily in Custer County, Oklahoma. The total preliminary adjusted value of consideration was $29.6 million. As of November 1, 2018, the effective date of the acquisition, the estimated proved oil and gas reserves for the acquired properties was 2.6 MMBoe net to us. The acquisition added approximately 8,667 net oil and gas leasehold acres to our Penn Sands area in Oklahoma including approximately 44 wells. The acquisitions included approximately 30 potential horizontal drilling locations which are anticipated to have a high percentage of oil relative to the total production stream. Of the acreage acquired, approximately 82% was held by production.

Dispositions. We had non-core asset sales, net of related expenses, of $21.8 million, $22.5 million, and $18.6 million, in 2019, 2018, and 2017, respectively. Proceeds from these sales reduced the net book value of the full cost pool with no gain or loss recognized.

We determined the value of some of our unproved oil and gas properties were diminished (in part or whole) based on an impairment evaluation and our anticipated future exploration plans. Those determinations resulted in $73.9 million and $10.5 million in 2019 and 2017, respectively of costs being added to the total of our capitalized costs being amortized. We did not have any impairment of unproved oil and natural gas properties in 2018. 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. We had no non-cash ceiling test write-downs during 2017 or 2018.

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

	Year Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Development:						
Oil	16	9.98	52	9.18	45	10.98
Natural Gas	99	19.17	63	22.96	23	13.90
Dry	—	—	2	1.02	2	0.83
Total development	115	29.15	117	33.16	70	25.71
Exploratory:						
Oil	—	—	—	—	—	—
Natural gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory	—	—	—	—	—	—
Total wells drilled	115	29.15	117	33.16	70	25.71

	Year Ended December 31,					
	2019		2018 (1)		2017	
	Gross	Net	Gross	Net	Gross	Net
Wells producing or capable of producing:						
Oil	1,534	604.79	1,533	598.50	1,554	632.85
Natural gas	4,601	1,598.32	4,775	1,734.96	4,887	1,797.66
Total	6,135	2,203.11	6,308	2,333.46	6,441	2,430.51

1. There were 56 gross wells with multiple completions.

We own interests in drilling two gross (0.002 net) wells started during 2020 as of February 28, 2020.

Cost for development drilling includes $77.2 million, $76.3 million, and $41.6 million in 2019, 2018, and 2017, respectively, to develop previously booked proved undeveloped oil and natural gas reserves.

This table summarizes our leasehold acreage at December 31, 2019:

	Year Ended December 31, 2019					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net (1)	Gross	Net
Total	509,930	319,756	86,892	48,504	596,822	368,260

1. Approximately 79% of the net undeveloped acres are covered by leases that will expire in the years 2020—2022 unless drilling or production extends the terms of 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 years indicated:

	Year Ended December 31,		
	2019	2018	2017
Average sales price per barrel of oil produced:			
Price before derivatives	$ 55.13	$ 63.78	$ 48.98
Effect of derivatives	2.36	(8.00)	0.46
Price including derivatives	$ 57.49	$ 55.78	$ 49.44
Average sales price per barrel of NGLs produced:			
Price before derivatives	$ 12.42	$ 22.58	$ 18.35
Effect of derivatives	—	(0.40)	—
Price including derivatives	$ 12.42	$ 22.18	$ 18.35
Average sales price per Mcf of natural gas produced:			
Price before derivatives	$ 1.88	$ 2.42	$ 2.49
Effect of derivatives	0.16	0.04	(0.03)
Price including derivatives	$ 2.04	$ 2.46	$ 2.46

	Year Ended December 31,		
	2019	2018	2017
Oil production (MBbls):			
Jazz Wilcox field	417	418	533
Buffalo Wallow field	243	258	127
All other fields	2,548	2,198	2,055
Total oil production	3,208	2,874	2,715
NGLs production (MBbls):			
Jazz Wilcox field	1,278	1,370	1,567
Buffalo Wallow field	1,237	1,235	728
All other fields	2,258	2,320	2,442
Total NGLs production	4,773	4,925	4,737
Natural gas production (MMcf):			
Jazz Wilcox field	14,361	17,494	16,799
Buffalo Wallow field	11,843	9,428	6,228
All other fields	26,861	28,704	28,233
Total natural gas production	53,065	55,626	51,260
Total production (MBoe):			
Jazz Wilcox field	4,089	4,703	4,900
Buffalo Wallow field	3,454	3,065	1,893
All other fields	9,282	9,302	9,203
Total production	16,825	17,070	15,996
Average production cost per equivalent Bbl [1]	$ 5.71	$ 6.50	$ 6.24

1. Excludes ad valorem taxes and gross production taxes.

Our Jazz Wilcox field in South Texas, which includes our Gilly, Segno, and Wildwood prospects and several smaller prospects, contained 21%, 14%, and 18% of our total proved reserves in 2019, 2018, and 2017, respectively, expressed on an oil-equivalent barrels basis. Our Buffalo Wallow field in Hemphill County, Texas, contained 10%, 29%, and 24% 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 more than 15% of our proved reserves.

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

	Year Ended December 31, 2019			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Total proved developed	12,196	23,030	220,187	71,924
Total proved undeveloped	—	—	—	—
Total proved	12,196	23,030	220,187	71,924

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 Company, L.P., (Ryder Scott), independent petroleum consultants, 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, 2019, and comprised 86% 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. Our internal audit group 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 2019 continuing education hours, Mr. Paradiso attended 6 hours of formalized training during the 2019 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 31 hours of formalized in-house training during 2019 covering such topics as 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 40 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 February 19, 2007. 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 Trenton Mitchell and Derek Smith.

Mr. Mitchell earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1994. He has been an employee of Unit since 2002. Initially, he was the Outside Operated Engineer and since 2003 he has served in the capacity of Reservoir Engineer and in 2010 he was promoted to Manager of Reservoir Engineering. Before joining Unit, he served in several engineering field and technical support positions with Schlumberger Well Services in their pumping services segment (formerly Dowell Schlumberger). He obtained his Professional Engineer registration from the State of Oklahoma in 2004. He has been a member of SPE since 1991 and joined the Society of Petroleum Evaluation Engineers (SPEE) in 2017.

Mr. Smith received a Bachelor of Science in Petroleum Engineering with a Minor in Business from the University of Tulsa in 2005. He worked for Apache Corporation immediately after in Production Engineering, then Reservoir Engineering, followed by Drilling Engineering for approximately one year each before moving to Corporate Reserves in 2008. He joined Unit in 2009 as a Corporate Reserves Engineer involved in reserve evaluation, acquisition appraisals, and prospect reviews with increasing levels of responsibility. He has been a member of SPE since 2000 and joined the SPEE in 2018.

As part of their continuing education Mr. Mitchell and Mr. Smith 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 oil, NGLs, and natural gas reserves, as defined in SEC Rule 4-10(a), 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 – before the time 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 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.

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 developed" oil, NGLs, and natural gas reserves are proved 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 to the cost of a new well. It can also be recovered through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved undeveloped" oil, NGLs, and natural gas reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. 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. Under no circumstances can estimates for proved undeveloped reserves be attributable to acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless those techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Proved Undeveloped Reserves. As of December 31, 2019, we did not have any proved undeveloped reserves.

Below, we summarize changes to our proved undeveloped reserves during 2019:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
Proved undeveloped reserves, January 1, 2019	7.4	14.3	158.7	48.1
Extensions and discoveries	—	—	—	—
Converted to developed	(2.7)	(2.2)	(25.0)	(9.1)
Revisions of previous estimates	(4.7)	(12.1)	(133.1)	(38.9)
Sale of reserves	—	—	(0.6)	(0.1)
Proved undeveloped reserves, December 31, 2019	—	—	—	—

During 2019, we converted 39 proved undeveloped well locations into proved developed wells at a cost of approximately $77.2 million. The downward revision to previous estimates is primarily 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. This resulted in the removal of 2.9 MMBbls of oil, 2.2 MMBbls of NGLs, and 20.0 Bcf of natural gas and the elimination of any extensions and disclosures.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2019, 2018, and 2017, 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 2019, sales to CVR Refining, LP accounted for 14% 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 2019, our mid-stream segment purchased $40.6 million of our natural gas and NGLs production and provided gathering and transportation services of $6.9 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements. In 2018 and 2017, we eliminated intercompany revenues of $88.7 million and $69.9 million, respectively, 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 our account and others. Our drilling operations are mainly in Oklahoma, Texas, New Mexico, Wyoming, North Dakota, and to a lesser extent in Colorado.

This table identifies certain information about our contract drilling segment:

	Year Ended December 31,		
	2019	2018	2017
Number of drilling rigs available for use at year end [(1)]	58.0	55.0	95.0
Average number of drilling rigs owned during the year	56.9	95.5	94.5
Average number of drilling rigs utilized	24.6	32.8	30.0
Utilization rate [(2)]	43 %	34 %	32 %
Average revenue per day [(3)]	$ 18,736	$ 16,429	$ 15,934
Total footage drilled (feet in 1,000's)	7,615	8,386	6,864
Number of wells drilled	423	539	468

1. In December 2018, we removed from service 41 drilling rigs, tubulars, hydraulic top drives, mud pumps, and other drilling equipment.
2. Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the year.
3. 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. Our drilling rigs can be transferred between divisions.

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. In 2019, 39 of our 58 drilling rigs were used in drilling services.

This table shows certain information about our drilling rigs as of February 28, 2020:

	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Drilling Rigs	18	40	58	20,190

Fluctuating commodity prices directly affect drilling rig utilization rates, both positively and negatively. In 2019, many operators planned their drilling budgets more toward the first half of the year. As commodity prices declined mid-year, so did drilling rig utilization. The volatility of commodity prices coupled with the supply and demand economic 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 impact of these conditions affects the demand for our drilling rigs.

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

	2019	2018	2017
First quarter	31.4	31.7	25.5
Second quarter	28.6	32.2	28.8
Third quarter	20.4	34.2	34.6
Fourth quarter	18.3	33.1	31.2

Drilling Rig Fleet. The following table summarizes the changes to our drilling rig fleet in 2019. A more complete discussion of changes over the last three years follows the table:

Drilling rigs available for use on January 1, 2019	55
Drilling rigs constructed	3
Total drilling rigs available for use on December 31, 2019	58

Dispositions, Acquisitions, and Construction. During 2017, we built our tenth BOSS drilling rig and placed it into service for a third party operator under a long term contract.

During 2018, we built our 11th BOSS drilling rig and placed it into service for a third party operator under a long term contract.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer use based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax). During 2019, we sold six of these drilling rigs and some of the other equipment to unaffiliated third parties. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. Seven drilling rigs and equipment will be marketed for sale throughout the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.9 million.

During 2019, we completed construction and placed into service with third party operators under long-term contracts our 12th and 13th BOSS drilling rigs. Our 14th BOSS drilling rig was completed and placed into service in December of 2019 for a third party operator under a long-term contract.

Drilling Contracts. Our 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 negotiable on a contract by contract basis.

The type of contract used determines our compensation. All of our contracts in 2019, 2018, and 2017 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.

The majority of our contracts are under term contracts, with the rest on 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 2019, EOG Resources, Inc., QEP Resources, Inc., and Slawson Exploration Company, Inc. were our largest third-party drilling customers accounting for approximately 12%, 12%, and 11% of our total contract drilling revenues, respectively. Our work for these customers were under multiple contracts and our business was not substantially dependent on a single contract. None of these individual contracts were considered material. 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, 2018, and 2017, our contract drilling segment drilled 50, 45, and 27 wells, respectively, for our oil and natural gas segment, or 12%, 8%, and 6%, respectively, of the total wells drilled by our contract drilling segment. Depending on the timing of the drilling services performed on our properties, those services may be deemed, for financial reporting purposes, to be associated with acquiring an ownership interest in the property. Revenues and expenses for these services are eliminated in our statement of operations, with any profit recognized reducing our investment in our oil and natural gas properties. 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, $22.5 million, and $13.4 million during 2019, 2018, and 2017, respectively, from our contract drilling segment and eliminated the associated operating expense of $14.2 million, $19.5

million, and $11.8 million during 2019, 2018, and 2017, respectively, yielding $1.6 million, $3.0 million, and $1.6 million during 2019, 2018, and 2017, respectively, as a reduction to the carrying value of our oil and natural gas properties.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries, for which we own a 50% interest. Its operations consist of buying, selling, gathering, processing, and treating natural gas. It operates three natural gas treatment plants, 11 processing plants, 19 active gathering systems, and approximately 2,080 miles of pipeline. Superior and its subsidiaries operate in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Gas gathered—Mcf/day	435,646	393,613	385,209
Gas processed—Mcf/day	164,482	158,189	137,625
NGLs sold—gallons/day	625,873	663,367	534,140

Dispositions and Acquisitions. This segment had no significant dispositions or acquisitions during 2017.

On April 3, 2018, we sold 50% of the ownership interest in our mid-stream segment, Superior. The purchaser is 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. We received $300.0 million from this sale. A portion of the proceeds were used to pay down our bank debt and the remainder were used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company and build additional BOSS drilling rigs. In connection with the sale of the interest in Superior, we took the necessary actions under the Indenture governing our outstanding senior subordinated notes to secure the ability to close the sale and have Superior released from the Indenture.

Superior is governed and managed under its Amended and Restated Limited Liability Company Agreement and the Master Services and Operating Agreement (MSA) signed by Superior and an affiliate of Unit, as both agreements may be amended occasionally. Further details are in Note 18 – Variable Interest Entity Arrangements.

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.

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 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, 2019, 76% of our mid-stream segment's total volumes and 72% 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, 2019, 24% of our mid-stream segment's total volumes and 28% of operating margins (as defined below) were under commodity-based contracts.

For each of the above contracts, 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 2019, ONEOK, Inc., Range Resources Corporation, and Centerpoint Energy Service, Inc. accounted for approximately 33%, 13%, and 10% of our mid-stream revenues, respectively. We believe that if we lost these customers, there are other customers available to purchase our gas and NGLs. During 2019, 2018, and 2017 our mid-stream segment purchased $40.6 million, $81.4 million, and $63.2 million, respectively, of our oil and natural gas segment's natural gas and

NGLs production, and provided gathering and transportation services of $6.9 million, $7.3 million, and $6.7 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.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for oil, NGLs, and natural gas significantly affect our revenues, operating results, cash flow, and our ability to grow our operations. Oil, NGLs, and natural gas prices have been volatile, and they will probably continue to be so. For each period indicated, this table shows the highest and lowest average prices our oil and natural gas segment received for its sales of oil, NGLs, and natural gas without considering the effect of derivatives:

	Oil Price per Bbl		NGLs Price per Bbl		Natural Gas Price per Mcf	
Quarter	**High**	**Low**	**High**	**Low**	**High**	**Low**
2017						
First	$ 50.48	$ 46.85	$ 20.71	$ 15.04	$ 3.76	$ 2.14
Second	$ 48.73	$ 43.49	$ 15.33	$ 14.36	$ 2.95	$ 2.30
Third	$ 49.66	$ 44.54	$ 19.99	$ 16.17	$ 2.53	$ 2.04
Fourth	$ 57.38	$ 49.62	$ 22.39	$ 21.13	$ 2.58	$ 1.93
2018						
First	$ 63.04	$ 58.74	$ 22.52	$ 20.03	$ 2.92	$ 2.08
Second	$ 68.61	$ 65.76	$ 23.46	$ 21.14	$ 2.23	$ 1.96
Third	$ 70.75	$ 68.38	$ 29.61	$ 25.15	$ 2.28	$ 2.19
Fourth	$ 69.88	$ 47.54	$ 25.12	$ 16.32	$ 3.72	$ 2.25
2019						
First	$ 56.44	$ 50.04	$ 16.45	$ 15.81	$ 2.86	$ 2.16
Second	$ 61.75	$ 53.87	$ 15.75	$ 8.62	$ 1.98	$ 1.58
Third	$ 57.99	$ 51.41	$ 8.86	$ 7.89	$ 1.60	$ 1.44
Fourth	$ 57.71	$ 52.11	$ 13.49	$ 12.85	$ 1.94	$ 1.63

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil and natural gas, market uncertainty, and many additional factors beyond our control, including:

- political conditions in oil producing regions;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and Russia to agree on prices and their ability or willingness to maintain production quotas;
- actions taken by foreign oil and natural gas producing nations;
- the price of foreign oil imports;
- imports and exports of oil and liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;
- United States storage levels of oil, NGLs, and natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
- worldwide economic conditions.

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. You are encouraged to read the Risk Factors discussed in Item 1A of this report for additional risks that can affect our operations.

Our contract drilling operations depend on the level of demand in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect demand. Because oil, NGLs, and natural gas prices are volatile, the level of demand for our services is also volatile.

Our mid-stream operations provide us greater flexibility in delivering our (and third parties) natural gas and NGLs from the wellhead to major natural gas and NGLs pipelines. Margins received for the delivery of these natural gas and NGLs depend on the price for oil, NGLs, and natural gas and the demand for natural gas and NGLs in our area of operations. If the price of NGLs falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to us to extract certain NGLs. The volumes of natural gas and NGLs processed depend highly on the volume and Btu content of the natural gas and NGLs gathered.

COMPETITION

All of 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.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

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. Effective January 1, 2019, we elected to terminate and wind down all of the remaining employee limited partnerships. In accordance with the partnership agreements, we, as the liquidating trustees, valued the interests of the limited partners using the formula provided in each partnership agreement and purchased those interests. Total purchase price for all of the limited partners' interests net of Unit's interest was $0.6 million. We have no plans to sponsor additional employee limited partnerships.

The employee partnerships each had a set annual percentage (ranging from 1% to 15%) of our interest that the partnership acquired in most of the oil and natural gas wells we drilled or acquired for our account during the year in which the partnership was formed. The total interest the participants had in our oil and natural gas wells by participating in these partnerships did not exceed one percent of our interest in the wells.

These partnerships are further described in Notes 3 and 12 to the Consolidated Financial Statements in Item 8 of this report.

EMPLOYEES

As of February 28, 2020, we had approximately 603 employees in our contract drilling segment, 237 employees in our oil and natural gas segment, 135 employees in our mid-stream segment, and 79 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

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, the Federal Energy Regulatory Commission (FERC) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. FERC's jurisdiction 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 jurisdiction 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 particular 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 the area of 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, 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 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 EPA in 2015 established publicly owned treatment works (POTWs) effluent guidelines and standards for oil and gas extraction facilities which reflected industry best practices for unconventional oil and gas extraction facilities.

The EPA and the U.S. Army Corp of Engineers (Army) in 2015 proposed a new expansive definition of the "waters of the United States," which the United States Court of Appeals for the Sixth Circuit stayed nationally. On February 28, 2017, an Executive Order was issued and directed that the EPA and Army consider interpreting the term "navigable waters" in a manner consistent with Justice Scalia's opinion in Rapanos v. United States (2006). On March 6, 2017, the EPA and Army announced their intention to review and rescind or revise the 2015 Clean Water Rule and on June 27, 2017 they issued a proposed rule and written recommendations (Obama rule). On January 22, 2018, the United States Supreme Court in National Association of Manufacturers v. Department of Defense, et al. vacated the Sixth Circuit's nationwide stay. As a result, on January 31, 2018, the EPA and Army issued a rule providing that the 2015 definition of "waters of the United States" will not apply until two years following the date this rule is published in the Federal Register. In addition, Army includes wetlands within its definition of "waters of the United States." However, due to ongoing litigation, the Obama rule only applies to 28 states, and is enjoined with respect to the other 22 states challenging the Obama rule until such time as the litigation is resolved. On December 1, 2018, the EPA and Army released a proposed rule which would restrict the definition of "waters of the United States" to traditional large navigable waters, rivers and lakes and territorial seas used in interstate or foreign commerce as well as the tributaries, navigable lakes and ponds and tributaries that provide perennial or intermittent flow to them, as well as ditches that are "artificial channels" used to carry water and meet the conditions of a tributary or are adjacent to wetlands, impoundments of jurisdictional waters, and wetlands which are adjacent to jurisdictional waters in a "typical year" or which are connected by a channel to "waters of the United States." In 2016, the United States Supreme Court in U.S. Army Corps of Engineers v. Hawkes held that landowners can challenge in court an Army Corps of Engineers jurisdictional determination. It is anticipated this decision will provide landowners an important tool in negotiating and resolving conflicts with federal agencies over the extent of wetlands on a property. During 2018, the United States Courts of Appeals for the Fourth and Ninth Circuits applied the so-called "hydrological connection" theory to extend jurisdiction of the Clean Water Act to cover pollutants that reach surface waters via groundwater. The Sixth Circuit addressed the same issue, but rejected the Fourth and Ninth Circuits' decisions and held the opposite, consistent with 1994 Fifth Circuit and 2001 Seventh Circuit decisions. In response to an early December 2018 United States Supreme Court invitation to comment on the Fourth and Ninth Circuit's decisions, the United States Solicitor General asked the United States Supreme Court to resolve the Circuit Courts' split on whether the Clean Water Act applies when pollutants from a point source reach navigable waters after traveling through the groundwater. Petitions for review of the Fourth and Ninth Circuits' decision were filed with the United States Supreme Court in October and briefing completed in November 2018.

Endangered Species Act. The federal Endangered Species Act, called the "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 proposed for protected status in areas in which we provide or could undertake operations. The U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries (NMFS) in 2016 issued final revised definitions relating to impacts on critical habitats for potentially endangered species allowing exclusion of certain areas if they will not result in the extinction of the species. In 2017, the Western Governor's Association issued a Policy Resolution calling on Congress to amend and reauthorize the ESA based upon seven broad goals to make the act more workable and understandable. In December 2017, the Interior Department announced that it is working on possible changes to the ESA with the FWS to revise the regulations for listing endangered and threatened species and for designation of critical habitat. On July 19, 2018, the FWS and NMFS issued their proposals to revise the ESA regulations, to include: (1) reinstating the prior two-step approach to designating critical habitat, first considering designation of occupied habitat and then considering non-occupied habitat only if the existing inhabited area is inadequate to ensure conservation of the species; and (2) removal from the definition of "adverse modification" by deleting the second sentence in the definition which includes impact to land that "preclude or significantly delay development [physical or biological] features" essential to the conservation of the species. However, some of the new proposals may be impacted by the United States Supreme Court's decision issued in late November 2018. In vacating a United States Court of Appeals for the Fifth Circuit decision involving an endangered species, in Weyerhaeuser Co. v. U.S. Fish & Wildlife Service, the Supreme Court held that (1) a proposed site must be "habitat" for an endangered species before the FWS can designate it as "habitat that is critical" and (2) federal courts should review for an abuse of discretion the FWS's decision not to exclude a site from designation. In other words, 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. 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.

Climate Change. Recent scientific studies have suggested that emissions of certain gases, commonly called "greenhouse gases," or GHGs, may be contributing to warming of the Earth's atmosphere. As a result there have been many regulatory developments, proposals or requirements, and legislative initiatives introduced in the United States (and other parts of the World) that are focused on restricting the emission of carbon dioxide, methane, and other greenhouse gases.

In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act if it represents a health hazard to the public. On December 7, 2009, the U.S. Environmental Protection Agency (EPA) responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of GHGs in the atmosphere threaten the public health and welfare of current and future generations, and that certain GHGs from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of GHG and hence to the threat of climate change. In addition, the EPA issued a final rule, effective in December 2009, requiring the reporting of GHG emissions from specified large (25,000 metric tons or more) GHG emission sources in the U.S., beginning in 2011 for emissions in 2010. During 2010, the EPA proposed revisions to these reporting requirements to apply to all oil and gas production, transmission, processing, and other facilities exceeding certain emission thresholds. On May 12, 2016, the EPA issued three final rules that together will curb emissions of methane, smog-forming volatile organic compounds (VOCs) and toxic air-pollutants such as benzene from new, reconstructed and modified oil and natural gas sources, while providing greater certainty about Clean Air Act permitting requirements for the industry (Methane Rule). First, the EPA issued updates to the New Source Performance Standards (NSPS) for the oil and natural gas industry to add requirements that the industry reduce emissions of GHGs and to cover additional equipment and activities in the oil and natural gas distribution chain by setting emissions limits for methane and to require owners/operators to find and repair methane and VOC leaks. Second, the EPA issued a source determination rule regarding the EPA's air permitting rules as they apply to the oil and natural gas industry. The EPA clarified when multiple pieces of equipment and activities must be deemed a single source for determining whether (i) major source Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review requirements apply regarding preconstruction permitting and (ii) a Title V Operating permit is required. Third, the EPA issued a final rule to implement the Minor New Source Review Program in Indian Country for oil and natural gas production designed to limit emissions of harmful air pollution while making the preconstruction permitting process more streamlined and efficient. These regulations will cause additional costs to reduce emissions of GHGs associated with our operations and could hurt demand for the crude oil we gather, transport, store or otherwise handle in connection with our services. Although the EPA announced in April 2017 it will reconsider the GHG oil and gas emissions rule and delay its compliance, lawsuits have prevented such an effort. On September 1, 2018, the EPA proposed revisions to its Methane Rule, which the EPA estimates would "significantly reduce regulatory burden, saving the industry tens of millions of dollars in compliance each year." The EPA proposes to revise (decrease) the monitoring frequencies for fugitive emissions (leaks) at non-low production well sites, low production well sites and compressor stations. The EPA also proposes to allow owners/operators up to 60 days after fugitive emissions are detected to complete repairs, provided that a first attempt at repair has to be made within the first 30 days.

Hydraulic Fracturing. 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 of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. On July 25, 2017, the Bureau of Land Management announced a proposal to rescind the 2015 Department of Interior final rule on hydraulic fracturing, a rule that was never in effect due to pending litigation. Multiple bills have been introduced in Congress that would (i) block federal regulation of hydraulic fracturing in favor of state rules, (ii) allow a state to regulate hydraulic fracturing on federal lands within that state, (iii) prevent federal regulation of hydraulic regulation to apply to any land held in trust or restricted status for the benefit of Indians without their express consent, (iv) repeal the exemption for hydraulic fracturing in the Safe Drinking Water Act, and/or (v) require the disclosure of chemicals used in hydraulic fracturing. 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, public disclosure of fracking fluids, waste disposal, and well construction requirements on these operations, and even restrict or ban hydraulic fracturing in certain circumstances.

On December 31, 2016, the EPA released its scientific Final Report on Impacts from Hydraulic Fracturing Activities on Drinking Water. The EPA states the report, which was done at the request of Congress, provides scientific evidence that hydraulic fracturing activities can affect drinking water resources in the United States under some circumstances. The EPA identifies six conditions under which impacts from hydraulic fracturing activities can be more frequent or severe and existing uncertainties and data gaps. Both the EPA and the United States Geological Survey (USGS) have made statements indicating that activities associated with hydraulic fracturing may be causing earthquakes, with the focus being on wastewater disposal wells rather than injection wells. In an August 2015 report sent to the Texas Railroad Commission, the EPA stated it believes there is a significant possibility that North Texas earthquake activity is associated with disposal wells. The USGS has stated that hydraulic fracturing causes small earthquakes, but they are almost always too small to be detected. Regarding disposal wells, the USGS has stated that the injection of wastewater and salt water by deep wells into the subsurface can cause earthquakes that are large enough to be felt and may cause damage. As a result, the USGS and its university partners have deployed seismometers at sites of known or possible injection induced earthquakes in Arkansas, Colorado, Kansas, Oklahoma, Ohio and Texas and that it is also developing methods to assess the earthquake hazard associated with wastewater injection wells.

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 GHGs 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

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENT AND RISK FACTORS

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. All statements, other than statements of historical facts, included or incorporated by reference in this document which addresses activities, events or developments which we expect or anticipate will or may occur, are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts," and similar expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information we file with the SEC in the future will automatically update and supersede information in this report.

These forward-looking statements include, among others, such things as:

- 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 of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final 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 established pipeline systems;
- 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 impacting our facilities and systems;
- our projected production guidelines for the year;

- our anticipated capital budgets;
- our financial condition and liquidity (including our ability to refinance our senior subordinated notes);
- the number of wells our oil and natural gas segment plans to drill during the year;
- our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods; and
- our plans to restructure our debt and the costs related to those plans.

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

- the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities we pursue;
- demand for our land drilling services;
- changes in laws or 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 the Unit credit agreement and indentures;
- the possibility that our common stock may be delisted;
- our ability to continue as a going concern;
- putative class action lawsuits that may result in substantial expenditures and divert management's attention; and
- other factors, most of which are beyond our control.

You should not place undue reliance on these 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 the date of this document to reflect incorrect assumptions or unanticipated events.

To help provide you with a more thorough understanding of the possible effects of these influences on any forward-looking statements made by us, this discussion outlines some (but not all) of the factors that could cause our consolidated results to differ materially from those that may be presented in any forward-looking statement made by us or on our behalf.

Demand for our contract drilling and mid-stream services depends substantially on the levels of expenditures by the oil and gas industry. A substantial or an extended decline in oil and gas prices could cause lower expenditures 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 substantially on the level of expenditures by the oil and gas industry for the exploration, development and production of oil and natural gas reserves. These expenditures depend generally 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 impact on demand for oil and natural gas. Declines, and anticipated declines, in oil and gas prices could also result in 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.

The oil and gas industry has historically experienced periodic downturns, which have been characterized by diminished demand for oilfield services and downward pressure on the prices we charge. Oil and natural gas prices have recently experienced record declines and are currently at record low levels in response to dramatic supply and demand uncertainty. In response, several exploration and production companies have recently announced plans to reduce their capital budgets and activity levels. We expect these changes will adversely affect the revenue, profitability, and cash flow from and, ultimately the financial position of, our business. A significant downturn in the oil and gas industry could cause a reduction in demand for oilfield services and could hurt our financial condition, results of operations and cash flows.

Oil, NGLs, and Natural Gas Prices. Besides the impact oil and gas prices may have on our contract drilling and mid-stream segments, the prices we receive for our oil, NGLs, and natural gas production directly affect our revenues, profitability, and cash flow and our ability to meet our projected financial and operational goals. The prices for oil, NGLs, and natural gas are determined on several 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 greatly influence the demand and prices for natural gas);
- the amount and timing of oil, liquid 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 the OPEC to set and maintain production levels for oil;
- oil and gas production levels by non-OPEC countries;
- the level of excess production capacity;
- political and economic uncertainty and geopolitical activity;
- governmental policies and subsidies;
- the costs of exploring for producing and delivering oil and gas; and
- technological advances affecting energy consumption.

Oil prices are extremely sensitive to influences domestic and foreign 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 price of oil fell approximately 20% on March 9, 2020 due to Saudi Arabia's decision to increase its production to record levels. We cannot anticipate whether or when production will return to normalized levels, and oil prices could remain at current levels or decline further, for an extended period of time.

In addition, prices of oil, NGLs, and natural gas have been at various times influenced by trading on the commodities markets. That trading has increased the volatility associated with these prices resulting in large differences in prices even on a week-to-week and month-to-month basis. These factors, especially when coupled with much of our product prices being determined daily, can, and do, lead to wide fluctuations in the prices we receive.

Based on our 2019 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 $423,000 per month ($5.1 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 have a $252,000 per month ($3.0 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 have a $371,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow.

To reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into derivative contracts such as 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 subject to our derivatives, but not otherwise. Should market prices for the production we have derivatives exceed the prices due under our derivative contracts, our derivative contracts then expose us to risk of financial loss and limit the benefit to us of those increases in market prices. During 2019, to help manage our cash flow and capital expenditure requirements, we had derivative contracts on approximately 53% and 56% of our 2019 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 responsive prices. A more thorough discussion of our derivative arrangements is contained in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this report in Item 7.

Uncertainty of Oil, NGLs, and Natural Gas Reserves; Ceiling Test. Many uncertainties are inherent in estimating quantities of oil, NGLs, and natural gas reserves and their values, including many factors beyond our control. The oil, NGLs, and natural gas reserve information in this report represents only an estimate of these reserves. Oil, NGLs, and natural gas reservoir engineering is a subjective and an inexact process of estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. 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 of 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 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. Accordingly, 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 regarding 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, in part, 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.

In addition, 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.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from those proved reserves, discounted at 10%. Application of this "ceiling test" generally requires pricing future revenue at the unescalated 12-month average price and requires a write-down for accounting purposes if we exceed the ceiling. We may be required to write-down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would cause a charge to earnings but would not impact our cash flow from operating activities. Once incurred, a write-down is not reversible. 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. We had no non-cash ceiling test write-downs during 2017 or 2018.

Debt and Bank Borrowing. We have incurred and expect to continue to 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. In 2011 and 2012, we issued $250.0 million (the 2011 Notes) and $400.0 million (the 2012 Notes), respectively, of senior subordinated notes (collectively, the Notes). We have, and will continue to have, a certain amount of indebtedness. At December 31, 2019, we had $108.2 million outstanding current portion of long-term debt under the Unit credit agreement and $16.5 million outstanding long-term debt under the Superior credit agreement, and $646.7 million, net of unamortized discount and debt issuance costs, under the Notes.

Depending on the amount of our debt, the cash flow needed to satisfy that debt and the covenants in our bank credit agreements and those applicable to the Notes 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 that are 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 additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt obligations depends on our future performance. If the requirements of our indebtedness are not satisfied, a default could be deemed to occur and our lenders or the holders of the Notes 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 "Risks Related to Our Financial Condition" and "Risks Related to Our Indebtedness" below.

Our existing debt, and our future debt, if any, is, largely, based on the costs associated with the projects we undertake and of our cash flow. Generally, our normal operating costs are those resulting from the drilling of oil and natural gas wells, the acquisition of 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, particularly the first two, are discretionary and we maintain some control regarding the timing or the need to incur them. But, sometimes, unforeseen circumstances may arise, like an unanticipated opportunity 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 additional 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.

RISK FACTORS

Many other factors could hurt our business. This discussion describes the material risks currently known to us. However, additional risks we do not know about or that we currently view as immaterial may also impair our business or hurt the value of our securities. You should carefully consider the risks described below together with the other information contained in, or incorporated by reference into, this report.

Substantial doubt exists as to our ability to continue as a going concern.

Our financial statements have been prepared assuming we will continue as a going concern. At December 31, 2019, we had approximately $0.6 million in cash and cash equivalents on hand. We generated revenues of $674.6 million and $843.3 million and cash from operating activities of $269.4 million and $352.7 million during the twelve months ended December 31, 2019 and 2018, respectively.

We have substantial debt obligations, including, as of December 31, 2019, $650.0 million in principal amount of the Notes, which mature in May 2021, $108.2 million drawn under the Unit credit agreement, which matures in November 2020 if the Credit Agreement Extension Condition is not satisfied on or prior to that date, and $16.5 million drawn under our Superior credit agreement. We have been unsuccessful in raising capital to refinance the Notes, and we may not complete our recent offer to exchange the Notes. Accordingly, we cannot assure our stockholders that we will be able to satisfy the Credit Agreement Extension Condition or repay borrowings under the Unit credit agreement at maturity. If we lack sufficient liquidity to satisfy our debt or other obligations, then, in the absence of a strategic transaction or alternative, we may seek protection under Chapter 11 of the U.S. Bankruptcy Code (Chapter 11) to restructure our business and capital structure, or sell or liquidate assets. Additionally, we have a significant amount of secured indebtedness that is senior to our unsecured indebtedness and a significant amount of total indebtedness that is senior to our existing common stock. As a result, implementation of a strategic transaction or alternative or a Chapter 11 proceeding could result in a limited recovery for unsecured noteholders, if any, and place equity holders at significant risk of losing all of their interests in our company.

A long and protracted restructuring could materially adversely affect our business.

We have engaged and continue to engage in discussions with the lenders under the Unit credit agreement and a committee of certain holders of our outstanding senior subordinated notes subject to a non-disclosure agreement regarding a possible restructuring of our indebtedness.

Our ability to make required payments under our indebtedness would be adversely affected if we were to be unable to successfully restructure our capital structure. The purpose of the restructuring discussions is to extend the maturity profile of our outstanding indebtedness and eliminate short to medium-term refinancing and related risks associated with our capital structure. The October 18, 2023 scheduled maturity date of the loans under the Unit credit agreement will accelerate to November 16, 2020 to the extent that, on or before that date, all our outstanding senior subordinated notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023. If we are not able to successfully restructure our indebtedness, doubt may arise about our ability to timely repay our outstanding senior subordinated notes.

Based on our cash flow forecasts, if the maturity date of the Unit credit agreement is accelerated to November 16, 2020, there is substantial doubt about our ability to pay the amount due under the Unit credit agreement on maturity.

Additionally, based on our current plan, we anticipate that we will be in violation of certain covenants of the Unit credit agreement on the filing of our quarterly report Form 10-Q for the quarter ended June 30, 2020, which is due on August 10, 2020. If we are unable to renegotiate the terms of that agreement or obtain a waiver, this could result in all amounts outstanding under the Unit credit agreement and our outstanding senior subordinated notes becoming immediately due and payable. Based on our cash flow forecasts, we would not have sufficient liquidity to repay our indebtedness.

If either of the above circumstances were to occur, at that point we would consider other restructuring alternatives available to us. Those alternatives may include asset dispositions, joint ventures, or alternative refinancing transactions or the commencement of a Chapter 11 proceeding with or without a pre-arranged plan of reorganization. There can be no assurance that any alternative restructuring arrangement or plan will be pursued or accomplished. Finally, such efforts have resulted, and will continue to result, in significant costs to us, including advisory and professional fees paid in connection with evaluating our alternatives.

A protracted financial restructuring would disrupt our business and would divert the attention of our management from the operation of our business and implementation of our business plan. It is possible that a prolonged financial restructuring or bankruptcy proceeding would cause us to lose many of our key management employees. The loss of key management employees would likely make it difficult for us to complete a financial restructuring and may make it less likely that we will be able to continue as a viable business.

The uncertainty surrounding a prolonged financial restructuring could also have other adverse effects on us. For example, it could also adversely affect:

- our ability to raise additional capital;
- our ability to capitalize on business opportunities and react to competitive pressures;
- our ability to retain and attract employees;
- our liquidity;
- how our business is viewed by investors, lenders, strategic partners, or customers; and
- our enterprise value.

We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.

As of December 31, 2019, we had approximately $758.2 million in principal amount of debt outstanding (including $108.2 million drawn under our Unit credit agreement and $650.0 million outstanding senior subordinated 6.625% notes). As of December 31, 2019, we had approximately $6.7 million of letters of credit issued and borrowing capacity of approximately $160.1 million under our Unit credit agreement, subject to credit agreement constraints.

The level of and terms and conditions governing our debt:

- increase our vulnerability to the cyclical nature of our business, economic downturns or other adverse developments in our business;
- could limit our ability to access capital markets, refinance our existing indebtedness, raise capital on favorable terms, or obtain additional financing for working capital, capital expenditures, acquisitions, debt service requirements, execution of our business strategy, or for other purposes;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size, or those that have less restrictive terms governing their indebtedness, thereby enabling competitors to take advantage of opportunities that our indebtedness may prevent us from pursuing;
- limit management's discretion in operating our business; and
- increase our cost of borrowing.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. We have drawn on our Unit credit agreement for liquidity and the borrowing base is subject to a redetermination in the first quarter of 2020. If our borrowing base decreases as a result of lower prices of oil, natural gas or NGL, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. To the extent that the value of the collateral pledged under our credit facility declines as a result of lower oil and natural gas prices, asset dispositions or otherwise, we may be required to pledge additional collateral to maintain the current availability of the commitments thereunder, and we cannot assure you that we will be able to maintain a sufficiently high valuation to maintain the current commitments. In addition, we cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we are unable to service our indebtedness and other obligations, we may be required to restructure or refinance all or part of our existing debt, sell assets, reduce capital expenditures, borrow more money or raise equity, some or all of which may not be available to us on terms acceptable to us, if at all, or such alternative strategies may yield insufficient funds to make required payments on our indebtedness. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness could be affected by our future performance and events or circumstances beyond our control. Failure to comply with these covenants would result in an event of default under such indebtedness, the potential acceleration of our obligation to repay outstanding debt and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under our other outstanding indebtedness. Any of the above risks could materially adversely affect our business, financial condition, cash flows and results of operations.

Shareholders may be diluted significantly through our efforts to obtain financing and satisfy obligations through the issuance of securities.

We may attempt to use non-cash consideration to satisfy obligations and restructure our debt, including shares of our common stock, preferred stock, or warrants to purchase shares of our common stock. These actions will result in dilution of the ownership interests of existing shareholders and may further dilute common stock book value, and could result in the loss of all or substantially all of their interests in our company.

Risks Related to Our Business

If demand for oil, NGLs, and natural gas is reduced, the prices we receive for and our ability to market and produce our oil, NGLs, and natural gas may be negatively affected.

Historically, oil, NGLs, and natural gas prices have been volatile, with significant increases and significant price drops being experienced occasionally. Various factors beyond our control will have a significant effect on oil, NGLs, and natural gas prices. Those factors include, among other things, the domestic and foreign supply of oil, NGLs, and natural gas, the price of imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity, the actions of OPEC and other large producing nations, and changes in existing and proposed federal regulation and price controls. For example, the price of oil fell approximately 20% on March 9, 2020 due to a dispute over production levels between Russia and Saudi Arabia, as a result of which Saudi Arabia increased its production to record levels. We cannot anticipate whether or when this dispute will be resolved and production returned to normalized levels. In the absence of a resolution, oil prices could remain at current levels, or decline further, for an extended period of time.

Volatility in oil, NGLs, and natural gas markets can be caused by other factors as well. Production from oil and natural gas wells in some geographic areas of the United States has been curtailed for considerable periods of time due to a lack of local market demand and transportation and storage capacity. It is possible, however, that some of our wells may be shut-in or that oil, NGLs, and natural gas will be sold on terms less favorable than might otherwise be obtained should demand for oil, NGLs, and natural gas decrease. Competition for markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Oil, NGLs, and natural gas surpluses could cause our inability to market oil, NGLs, and natural gas profitably, causing us to curtail production and/or receive lower prices for our oil, NGLs, and natural gas, situations which would have a material adverse effect on our cash flows, results of operations and financial position.

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 terms for certain financings less attractive, and in certain cases, result in the unavailability of certain types of financing. Because credit and equity market turmoil, we may not be able to obtain debt or equity financing, or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

Oil, NGLs, and natural gas prices are volatile, and low prices have negatively affected our financial results and could do so in the future.

Our revenues, operating results, cash flow, and growth depend substantially on prevailing prices for oil, NGLs, and natural gas, which are at historically low levels. Oil, NGLs, and natural gas prices and markets have been volatile, and they are likely to continue to be volatile. A continuation of the current price environment or any further decline in prices would have a negative impact on our future financial results and our ability to grow our business segments.

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil, NGLs, and natural gas, market uncertainty, and many additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions;
- the ability of the members of the OPEC to agree on prices and their ability or willingness to maintain production quotas;
- actions taken by foreign oil and natural gas companies;
- the price of foreign oil imports;
- imports and exports of oil and liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;

- United States storage levels of oil, NGLs, and natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
- worldwide economic conditions.

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 contract drilling operations depend on levels of activity in the oil, NGLs, and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil, NGLs, and natural gas exploration and production in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect the level of that activity. Because oil, NGLs, and natural gas prices are volatile, the level of exploration and production activity can also be volatile. Any decrease from current oil, NGLs, and natural gas prices could further depress the level of exploration and production activity. This, in turn, would likely result in further declines in the demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows, and profitability. As a result, the future demand for our drilling services is uncertain. Oil and natural gas prices have recently experienced record declines and are currently at record low levels in response to dramatic supply and demand uncertainty. In response, several exploration and production companies recently announced plans to reduce their capital budgets and activity levels. We expect these changes will adversely affect the revenue, profitability and cash flow from and, ultimately the financial position of, our business.

The industries in which we operate are highly competitive, and many of our competitors have resources greater 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 better withstand periods of low drilling rig utilization, to compete more effectively based on price and technology, to build new drilling rigs or acquire existing drilling rigs, and to provide drilling rigs more quickly than we do in periods of high drilling rig utilization.

The oil and natural gas industry is also highly competitive. We compete in the areas of 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. In addition, we must compete with major and independent oil and natural gas concerns in recruiting and retaining qualified employees. 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 areas of 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.

Growth through acquisitions is not assured.

We have experienced growth in 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, and there can be 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. And we are likely to continue to face intense competition from other companies for acquisition opportunities.

There can be no assurance we will:

- be able to identify suitable acquisition opportunities;
- have sufficient capital resources to complete additional acquisitions;

- successfully integrate acquired operations and assets;
- effectively manage the growth and increased size;
- maintain the crews and market share to operate any future drilling rigs we may acquire; or
- improve our financial condition, results of operations, business or prospects in any material manner because of any completed acquisition.

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

Successful acquisitions, particularly those of oil and natural gas companies or of oil and natural gas properties, require an assessment of 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 operations have significant capital requirements, and our indebtedness could have important consequences.

We have experienced and will continue to experience substantial capital needs for our operations. We have $646.7 million of indebtedness outstanding (net of unamortized discount and debt issuance costs) under the senior subordinated notes we have issued to-date and, in addition, may borrow up to $200.0 million under the Unit credit agreement and up to $200.0 million under the Superior credit agreement. As of February 28, 2020, we had $124.0 million in outstanding borrowings under our Unit credit agreement with $20.0 million in cash and had $13.0 million in outstanding borrowings under our Superior credit agreement. Our level of indebtedness, the cash flow to satisfy our indebtedness, and the covenants governing our indebtedness could:

- limit funds available for financing 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 some of our competitors that are less leveraged than we are;
- make us more vulnerable during periods of low oil, NGLs, and natural gas prices or if downturn in our business occurs; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt service and other contractual and contingent obligations will depend on our future performance. In addition, lower oil, NGLs, and natural gas prices could cause future reductions in the amount available for borrowing under our credit agreements, reducing our liquidity, and even triggering mandatory loan repayments. See "Risks Related to Our Financial Condition" and "Risks Related to Our Indebtedness" below.

The instruments governing our indebtedness contain various covenants limiting the conduct of our business.

The indentures governing our senior subordinated notes and our credit agreements contain various restrictive covenants that limit the conduct of our business. These agreements place certain limits on our ability to, among other things:

- incur additional indebtedness, guarantee obligations or issue disqualified capital stock;
- pay dividends or distributions on our capital stock or redeem, repurchase or retire our capital stock;
- make investments or other restricted payments;
- invest in Unrestricted Subsidiaries over $200.0 million;
- grant liens on assets;
- enter into transactions with stockholders or affiliates;
- sell assets;

- issue or sell capital stock of certain subsidiaries; and
- merge or consolidate.

In addition, our credit agreements also requires us to maintain a minimum current ratio and a maximum senior indebtedness or leverage ratio.

If we violate the restrictions in the indentures governing our senior subordinated notes, our credit agreements or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness and any other indebtedness to which a cross-acceleration or cross-default provision applies. If that occurs, we may not make the required payments or borrow sufficient funds to refinance that debt. Even if new financing were available at that time, it may not be on terms acceptable to us. In addition, lenders may be able to terminate any commitments they had made to make available further funds. See "Risks Related to Our Financial Condition" and "Risks Related to Our Indebtedness" below.

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

Production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we replace the reserves we produce, our reserves will decline, resulting eventually in a decrease in oil, NGLs, and natural gas production and lower revenues and cash flow from operations. Historically, we have increased reserves after taking production into account through exploration and development. We have conducted these activities on our existing oil and natural gas properties and on newly acquired properties. We may not continue to replace reserves from these activities at acceptable costs. Lower prices of 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.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions significantly larger than those consummated by us. We cannot assure you we will successfully consummate any acquisition, that we can acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

The competition for producing oil and natural gas properties is intense. This competition could mean that to acquire properties we must pay higher prices and accept greater ownership risks than we have in the past.

Our exploration and production and mid-stream operations involve high business and financial risk which could hurt us.

Exploration and development involve numerous 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. Numerous factors beyond our control may cause the curtailment, delay, or cancellation of drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- capacity of pipeline systems;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs, pressure pumping services, or delivery crews and the delivery of equipment.

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 time frame, or at all. Lack of drilling success will have an adverse effect on our future results of operations and financial condition.

Our mid-stream operations involve numerous 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;
- 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.

Many of the wells from which we gather and process natural gas are operated by other parties. We have little control over the operations of those wells which can act to increase our risk. Operators of those wells may act in ways not in our best interests.

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

The success of our three segments 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, and other professionals. Competition for these professionals can be intense, particularly when the industry is experiencing favorable conditions.

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 sometimes enter into derivative contracts. These derivative contracts apply to only a portion of our production and provide only partial price protection against declines in oil, NGLs, and natural gas prices. These derivative contracts may expose us to risk of financial loss and limit the benefit to us of increases in prices.

Estimates of our reserves are uncertain and may prove inaccurate.

Numerous uncertainties are inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. 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;
- development costs; and
- workover and remedial costs.

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

The information regarding discounted future net cash flows should not be considered as the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices on the first day of the month for each month within the 12-month period before the end of the reporting period and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by these factors:

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

In addition, the 10% per year discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry.

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.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. 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 month for each month within the 12-month period before the end of the reporting period, unless prices were defined by contractual arrangements, and requires a write-down for accounting purposes if the ceiling is exceeded. We may be required to write-down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would cause a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible later. 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 additional write downs in one or more succeeding periods. This would be the case when months with higher commodity prices roll off the 12-month period 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 are required to 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 any of 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 property, equipment, and related intangible assets. Once these values have been reduced, they are not reversible.

Our operations present inherent risks of loss that, if not insured or indemnified against, could hurt our results of operations.

Our contract drilling operations are subject to many hazards inherent in the drilling industry, 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 the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract for some of these risks. If we cannot transfer these risks to drilling customers by contract or indemnification agreements (or to the extent 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. However, some risks are not covered by insurance and 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 the failure of a customer to meet its indemnification obligations, could cause substantial losses. In addition, 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.

We do not operate many of the wells in which we own an interest. Our operating risks for those wells and our ability to influence the operations for those wells are less subject to our control. Operators of those wells may act in ways not in our best interests.

Governmental and environmental regulations could hurt our business.

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, rates of production, 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. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the number of wells drilled or the allowable production from successful wells, which could limit 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 frequently change, we cannot assure you that future laws and regulations, including changes to existing laws and regulations, will not hurt our business. The United States Congress and White House administration may impose or change laws and regulations that will hurt our business. Stricter standards, greater regulation, and more extensive permit requirements, could increase our future risks and costs related to environmental matters. In addition, 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.

Any future implementation of price controls on oil, NGLs, and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose price controls on either oil, natural gas, or both. There is no way at this time to know what result these efforts will have nor, if implemented, their effect on our operations. However, it is possible that these efforts, if successful, would limit the amount we might get for our future oil, NGLs, and natural gas production. Any future limits on the price of oil, NGLs, and natural gas could also cause hurting the demand for our drilling services.

Provisions of Delaware law and our by-laws and charter could discourage change in control transactions and prevent shareholders from receiving a premium on their investment.

Our by-laws and charter provide for a classified board of directors with staggered terms and authorizes the board of directors to set the terms of preferred stock. In addition, our charter and Delaware law contain provisions that impose restrictions on business combinations with interested parties. Because of our by-laws, charter, and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. These provisions may make it more difficult for our shareholders to benefit from transactions opposed by an incumbent board of directors.

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

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, 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 certain that we can implement technologies timely or at a cost acceptable to us. One or more technologies that we use or that we may implement may become obsolete or may not work as we expected and we may be hurt.

We may be affected by climate change and market or regulatory responses to climate change.

Climate change, including the impact of potential global warming regulations, could have a material adverse effect on our results of operations, financial condition, and liquidity. Restrictions, caps, taxes, or other controls on emissions of greenhouse gases, including diesel exhaust, could significantly increase our operating costs. Restrictions on emissions could also affect our customers that (a) use commodities we carry to produce energy, (b) use significant energy in producing or delivering the commodities we carry, or (c) manufacture or produce goods that consume significant energy or burn fossil fuels, including chemical producers, farmers and food producers, and automakers and other manufacturers. Significant cost increases, government regulation, or changes of consumer preferences for goods or services relating to alternative sources of energy or emissions reductions could materially affect the markets for the commodities associated with our business, which could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives encouraging the use of alternative sources of energy could also affect certain of our customers and the markets for certain of the commodities associated with our business in an unpredictable manner that could alter our business activities. Finally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change. These factors, individually or in operation with one or more of the other factors, or other unforeseen impacts of climate change could reduce the business activity we conduct and have a material adverse effect on our results of operations, financial condition, and liquidity.

Public health threats could have an adverse effect on our operations and financial results.

Public health threats and other highly communicable diseases, outbreaks of which have already occurred in various parts of the world, could adversely impact our operations, the operations of our customers and the global economy.

In particular, the outbreak in December 2019 of a novel coronavirus (COVID-19) in China has resulted in quarantines, restrictions on travel to and from China and a decrease in economic activity in China, the world’s second largest economy. To date, these impacts have not had a material adverse effect on our business but no assurance can be given that they will not have such an effect, or that any further spread of the novel coronavirus (COVID-19) will not have a material adverse effect on our business, operations and financial results.

The results of our operations 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 2019, sales to CVR Refining, LP accounted for 14% of our oil and natural gas revenues. EOG Resources, Inc., QEP Resources, Inc., and Slawson Exploration Company, Inc. were our largest third-party drilling customers accounting for approximately 12%, 12%, and 11% of our total contract drilling revenues, respectively. And for our mid-stream segment, ONEOK, Inc., Range Resources Corporation, and Centerpoint Energy Service, Inc. accounted for approximately 33%, 13%, and 10% of our revenues, respectively. No other third party customer accounted for 10% or more of any of our individual segment revenues. Any of our customers may choose not to use our services and losing 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.

Shortage of completion equipment and services could delay or otherwise hurt our oil and natural gas segment's operations.

As there is an increase in horizontal drilling activity in certain areas, shortages could cause the availability of third party equipment and services required for completing wells drilled by our oil and natural gas segment. We could experience delays in completing some of our wells. Although we can try to reduce the delays associated with these services, we anticipate these services will be in high demand for the immediate future and could delay, restrict, or curtail part of our exploration and development operations, which could in turn harm our results.

Our mid-stream segment 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.

The counterparties to our commodity derivative contracts may not perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil, NGLs, and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, and to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. 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 results of operations.

We rely on management and other key employees.

We depend greatly 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 and/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. Any claims or litigation, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

Derivative regulations in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was passed by Congress and signed into law. This Act contains significant derivative regulations, requiring that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly called margin) for such transactions. This Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes several defined terms used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use crude oil and natural gas derivative instruments regarding a portion of our expected production to reduce commodity price uncertainty and enhance the predictability of cash flows relating the marketing of our crude oil and natural gas. As commodity prices increase, our derivative liability positions increase; however, none of our current derivative contracts require posting margin or similar cash collateral when there are changes in the underlying commodity prices referred to in these contracts.

Depending on the rules and definitions adopted by the Commodity Futures Trading Commission, we could have to post collateral with our dealer counterparties for our commodities derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral would cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral would likely cause additional costs being passed on to us, thereby decreasing the effectiveness of our derivative contracts and our profitability.

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 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 the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the Environmental Protection Agency (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 using diesel. The EPA is also seeking to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the Bureau of Land Management has imposed requirements for hydraulic fracturing activities of federal lands. In addition, Congress has occasionally considered legislation to provide for federal regulation of hydraulic-fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which 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. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. Besides state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling and/or hydraulic fracturing. If state, local, or municipal legal restrictions are adopted in areas where we are conducting, or plan to conduct operations, we may incur additional 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/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic-fracturing practices, and a committee of the United States House of Representatives investigated hydraulic-fracturing practices. Furthermore, several federal agencies are analyzing, or have been requested to review, many environmental issues associated with hydraulic fracturing. The EPA is evaluating the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In addition, the U.S. Department of Energy has investigated practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods.

And certain members of Congress have called on the U.S. Government Accountability Office to investigate how hydraulic fracturing might hurt water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, and uncertainties associated with those estimates. These ongoing or proposed studies, depending on their course and results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory processes.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or implementing regulations regarding hydraulic fracturing could cause a decrease in completing of new oil and gas wells, increased compliance costs and time, which could hurt our financial position, results of operations, and cash flows.

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we cannot acquire adequate supplies of water for our drilling operations and/or completions or cannot dispose of or recycle the water we use at a reasonable cost and under applicable environmental rules.

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 provide coverage for losses solely related to hydraulic fracturing operations; however, 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 regarding increased seismic activity in Oklahoma and Kansas.

We conduct oil and natural gas exploration, development and drilling activities in Oklahoma, Kansas, and elsewhere. In recent years, Oklahoma and Kansas have experienced a significant increase in earthquakes and other seismic activity. Some parties believe there is a correlation between certain oil and gas activities and the increased occurrence of earthquakes. The extent of this correlation is the subject of studies by both state and federal agencies the results of which remain uncertain. We cannot state at this time what if any 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 quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our oil and natural gas segment operations, could adversely affect our operations. The imposition of 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 have an adverse effect on our operations and financial condition.

We may decide not to drill some prospects we have identified, and locations we drill may not yield oil, NGLs, and natural gas in commercially viable quantities.

Our oil and natural gas segment's prospective drilling locations are in various stages of evaluation, 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. As a result, we may not increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial position, and results of operations. In addition, the SEC's reserve reporting rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of booking. At December 31, 2019, we did not have any proved undeveloped drilling locations. These were removed due to the uncertainty regarding our ability to finance future capital expenditures.

The cost of drilling, completing, and operating a well is often uncertain, and cost factors can hurt the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, NGLs, and natural gas to be commercially viable after drilling, operating, and other costs.

The borrowing base under the Unit credit agreement is determined semi-annually at the discretion of the lenders and is based in a large part 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 Unit credit agreement. If outstanding borrowings are over the borrowing base, we must (a) repay the amount in excess of the borrowing base, (b) dedicate additional properties to the borrowing base, or (c) begin monthly principal payments under the Unit credit agreement.

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

Superior must maintain a funded debt to consolidated EBITDA ratio of not greater than 4.00 to 1.00. As a result, if Superior’s EBITDA falls below $50.0 million, its maximum funded debt would be limited to 4.00 times consolidated EBITDA.

We have $650.0 million outstanding under our 6.625% Senior Subordinated Notes that mature on May 15, 2021.

Our ability to make scheduled payments of the principal and interest on or to refinance our outstanding 6.625% senior subordinated notes, depends on our financial and operating performance, which is subject to economic, financial, competitive and other factors, many of which are beyond our control. In addition, our ability to refinance this indebtedness will depend on the capital and credit markets and our financial condition prevailing at such time. We cannot provide assurance that our operating performance will generate sufficient cash flow or that our capital resources will be sufficient for payment of our obligations under this indebtedness or that we will be able to refinance this indebtedness on desirable terms, if at all, which could result in increased costs to us or require us to sell material assets or operations or use our available cash to meet our obligations under this indebtedness. See "Risks Related to Our Financial Condition" and "Risks Related to Our Indebtedness" below.

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 that of our customers, which could hurt our operations and financial results.

The federal Endangered Species Act (the ESA) and analogous state laws regulate a variety of 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. The designation of 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 the amount of 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 proposed for protected status in areas in which we provide or could in the future undertake operations. In 2016, the U.S. Fish and Wildlife Service and the National Marine Fisheries issued final revised definitions relating to impacts on critical habitats for potentially endangered species allowing exclusion of certain areas so long as they will not result in the extinction of the species. In 2017, the Western Governor's Association issued a Policy Resolution calling on Congress to amend and reauthorize the ESA based upon seven broad goals to make the act more workable and understandable. In December 2017, the U.S. Department of Interior (the Interior Department) announced that it is working on possible changes to the ESA with the U.S. Fish and Wildlife Service to revise the regulations for listing endangered and threatened species and for designation of critical habitat. 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, adversely affect our results of operations and financial position.

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, which we call BOSS drilling rigs. This new design should position us to better meet the demands of our customers. Constructing any future new BOSS drilling rigs is subject to the risks of delays or cost overruns inherent in any large construction project because of numerous possible factors, including:

- shortages of equipment, materials or skilled labor;
- work stoppages and labor disputes;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials used in construction of our drilling rigs, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- unforeseen design and engineering problems;
- failure or delay in obtaining acceptance of the drilling rig from our customer;
- failure or delay of third party equipment vendors or service providers; and
- lack of demand from the downturn in the oil and gas industry.

On our new BOSS drilling rigs, there can be no assurance we will:

- obtain additional new-build contract opportunities; or
- improve our financial condition, results of operations or prospects because of the new drilling rigs.

While we hold certain patents regarding our BOSS drilling rig design, it is still possible that third parties may claim we infringe their intellectual property rights. We may receive notices from others claiming 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. Besides money damages, in some jurisdictions plaintiffs can seek injunctive relief that may limit or prevent marketing and use of our drilling rigs that have infringing technologies.

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 significantly affect the energy industry, and economic conditions, including our operations and our customers, as well as 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 targets in the United States. A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss. Our insurance may not protect us against such occurrences. Consequently, 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.

The oil and natural gas industry has become increasingly dependent upon 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, are also dependent 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 for purposes of misappropriating 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 result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

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 in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third-party liability, including the following:

- a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- a cyber-attack on our facilities may result in equipment damage or failure;
- a cyber-attack on mid-stream or downstream pipelines could prevent our product from being delivered, resulting in a loss of 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 result in events of non-compliance which could lead to regulatory fines or penalties; and

- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our units.

Implementation of various controls and processes to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. We are not aware that any attempts to breach our systems have successfully occurred.

We are the subject of putative class action lawsuits that may result in substantial expenditures and divert management's attention.

We are the subject of putative class action lawsuits in Oklahoma raising allegations that we underpaid royalties and that we failed to pay interest on untimely royalty payments. These lawsuits seek various remedies, including damages, injunctive relief, and attorney's fees. For additional information on these lawsuits, see Item 3 Legal Proceedings in this Annual Report on Form 10-K.

Although we believe that the allegations in these lawsuits are without merit and intend to defend such litigation vigorously, litigation is subject to inherent uncertainties, and an adverse result in one of these lawsuits or other matters that may arise from time to time could have a material adverse effect on our business, results of operations and financial condition. Defending the lawsuits may be costly and, further, could require significant involvement of our senior management and may divert management's attention from our business and operations.

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

Our variable rate debt under both the Unit 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 such that it continues to exist after 2021. There is no guarantee that a transition from LIBOR to an alternative will not result in financial market disruptions, significant increases in benchmark rates or borrowing costs to borrowers, any of which could have an adverse effect on our business, financial condition and results of operations.

Ineffective internal controls could impact 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 with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, including any failure to implement required new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed and we could fail to meet our financial reporting obligations.

Risks Related to Our Financial Condition

Our common stock may be delisted from the New York Stock Exchange.

Our common stock is currently listed on the New York Stock Exchange (the "NYSE"). We may fail to comply with the continued listing requirements of the NYSE, which may result in the delisting of our common stock. The NYSE continued listing requirements require, among other things, that the minimum trading price of our common stock not fall below $1.00 for 30 consecutive trading days. On December 19, 2019, we were notified that we were not in compliance with this requirement. Under the NYSE's rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. If we are unable to cure this deficiency within the six months following the receipt of the notice from the NYSE, the NYSE might delist our common stock. Delisting would have an adverse effect on the liquidity of our common stock and, as a result, the market price for our common stock might become more volatile. Delisting could also make it more difficult for us to raise additional capital. In addition, the NYSE has other continued listing criteria that we are at risk of violating. For example, continued declines in our stock price could result in a delisting under the NYSE's "abnormally low selling price" criteria, which the NYSE views to be a trading price of less than $0.16 per share or its minimum average market capitalization requirement of $15.0 million. There is no available cure for these deficiencies. On March 10, 2020, our per share trading price closed at $0.25 and we had a market capitalization of $13.8 million.

We may not complete the Exchange Offer and Consent Solicitation at all, or may complete the Exchange Offer with respect to less than all of our senior subordinated notes.

The completion of the currently filed Exchange Offer and Consent Solicitation is subject to the satisfaction, or in certain cases, waiver of specified conditions as described in the Registration Statement. If the conditions to the completion of the Exchange Offer and Consent Solicitation are not satisfied or, if permitted, waived, the Exchange Offer may not be completed.

Our ability to make required payments under our indebtedness would be adversely affected if we were to be unable to complete the Exchange Offer and Consent Solicitation. The purpose of the Exchange Offer is to extend the maturity profile of our outstanding indebtedness and eliminate short to medium-term refinancing and related risks associated with our capital structure. The October 18, 2023 scheduled maturity date of the loans under the Unit credit agreement will accelerate to November 16, 2020 to the extent that, on or before that date, all our senior subordinated notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023 (the "Credit Agreement Extension Condition"). If we complete the Exchange Offer with respect to less than all of our senior subordinated notes, then the Credit Agreement Extension Condition will not be immediately satisfied and we may not be able to satisfy it thereafter. If we are not able to complete the Exchange Offer and Consent Solicitation, doubt may arise about our ability to timely repay our senior subordinated notes.

If we are unable to consummate the Exchange Offer and Consent Solicitation, or less than all of our senior subordinated notes are tendered in the Exchange, we will consider other restructuring alternatives available to us at that time. Those alternatives may include asset dispositions, joint ventures, or alternative refinancing transactions or the commencement of a Chapter 11 proceeding with or without a pre-arranged plan of reorganization. There can be no assurance that any alternative restructuring arrangement or plan will be pursued or accomplished. If we are unable to satisfy the Credit Agreement Extension Condition, there can be no assurance that we will be able to repay or refinance the Unit credit agreement on its accelerated maturity date or our senior subordinated notes on their existing maturity date. If the Exchange Offer is not completed or is delayed, the market prices of our senior subordinated notes may decline to the extent that the current market prices reflect an assumption that the Exchange Offer (or a similar transaction) will be completed and/or the Credit Agreement Extension Condition will be satisfied.

The Exchange Offer and Consent Solicitation have resulted, and will continue to result, in significant costs to us, including advisory and professional fees paid in connection with evaluating our alternatives under our senior subordinated notes and pursuing the Exchange Offer and Consent Solicitation.

Risks Related to the Restructuring of Our Indebtedness

Risks related to the restructuring of our indebtedness

We have engaged and continue to engage in discussions with the lenders under the Unit credit agreement and a committee of certain holders of our outstanding senior subordinated notes subject to a non-disclosure agreement regarding a possible restructuring of our indebtedness.

Our ability to make required payments under our indebtedness would be adversely affected if we were to be unable to successfully restructure our capital structure. The purpose of the restructuring discussions is to extend the maturity profile of our outstanding indebtedness and eliminate short to medium-term refinancing and related risks associated with our capital structure. The October 18, 2023 scheduled maturity date of the loans under the Unit credit agreement will accelerate to November 16, 2020 to the extent that, on or before that date, all our outstanding senior subordinated notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023. If we are not able to successfully restructure our indebtedness, doubt may arise about our ability to timely repay our outstanding senior subordinated notes.

Based on our most recent cash flow forecasts, if the maturity date of the Unit credit agreement is accelerated to November 16, 2020, there is substantial doubt about our ability to pay the amount due under the Unit credit agreement on maturity.

Additionally, based on our current plan, we anticipate that we will be in violation of certain covenants of the Unit credit agreement on the filing of our quarterly report Form 10-Q for the quarter ended June 30, 2020, which is due on August 10,

2020. If we are unable to renegotiate the terms of that agreement or obtain a waiver, this could result in all amounts outstanding under the Unit credit agreement and our outstanding senior subordinated notes becoming immediately due and payable. Based on our most recent cash flow forecasts, we would not have sufficient liquidity to repay our indebtedness.

If either of the above circumstances were to occur, at that point we would be required to consider other restructuring alternatives available to us. Those alternatives may include asset dispositions, joint ventures, or alternative refinancing transactions or the commencement of a Chapter 11 proceeding with or without a pre-arranged plan of reorganization. There can be no assurance that any alternative restructuring arrangement or plan will be pursued or accomplished. We have a significant amount of secured indebtedness that is senior to our unsecured indebtedness and a significant amount of total indebtedness that is senior to our existing common stock. As a result, any alternative restructuring arrangement or plan could result in a limited recovery for unsecured noteholders, if any, and place equity holders at significant risk of losing all of their interests in the company.

A long and protracted restructuring could cause us to lose key management employees and otherwise adversely affect our business.

A protracted financial restructuring would disrupt our business and would divert the attention of our management from the operation of our business and implementation of our business plan. It is possible that a prolonged financial restructuring or Chapter 11 proceeding would cause us to lose many of our key management employees. The loss of key management employees would likely make it difficult for us to complete a financial restructuring and may make it less likely that we will be able to continue as a viable business.

The uncertainty surrounding a prolonged financial restructuring could also have other adverse effects on us. For example, it could also adversely affect:

- our ability to raise additional capital;
- our ability to capitalize on business opportunities and react to competitive pressures;
- our ability to retain and attract employees;
- our liquidity;
- how our business is viewed by investors, lenders, strategic partners, or customers; and
- our enterprise value.

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

Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson, and Charlotte Abernathy are the Plaintiffs and are royalty owners in oil and gas drilling and spacing units for which the company's exploration segment distributes royalty. The Plaintiffs' central allegation is that the company's exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We have asserted several defenses including that the deductions are permitted under Oklahoma law. We have also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012 the Oklahoma Court of Civil Appeals reversed the trial court's order certifying the class. The Plaintiffs petitioned the Supreme Court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. On January 22, 2013, Plaintiffs filed a second request to certify a smaller class of royalty owners than their first attempt. Since then, the Plaintiffs have further amended their proposed class to just include royalty owners under certain leases in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. On July 29, 2019, the trial court denied the Plaintiffs' second motion for class certification. Plaintiffs are appealing the order denying class certification.

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 Unit Petroleum Company 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 Unit Petroleum 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. We have asserted several defenses including that the case cannot be properly certified as a class action because of the wide variety of circumstances that determine whether a royalty payment was timely made or has accrued interest under Oklahoma law. Further, Plaintiff's requests for relief beyond payment of interest allegedly due are barred by statute. We have filed a summary judgment motion as to named Plaintiff's individual claims. On February 28, 2020, the Court granted us a summary judgment on several of the Plaintiff's individual clams, including standing, but found that some claims presented fact issues. The Plaintiff has filed a motion with the Court asking it to reconsider its ruling. The issue of class certification will not be heard, if at all, until the issue of the named Plaintiff's standing and the pending fact issues are finally resolved.

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 Unit Petroleum Company styled Chieftain Royalty Company v. Unit Petroleum Company in LeFlore County, Oklahoma. Plaintiff alleges that Unit Petroleum 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. Unit has numerous defenses including that it has fulfilled its lease royalty obligations with respect to gas consumed as fuel. As to the propriety of class certification, we are defending on the grounds that the class involves thousands of different leases that have to be individually examined and construed, making class-wide liability determinations impossible. On June 26, 2019, Plaintiff moved for class certification. On February 6, 2020, the court entered its order certifying the class. We have appealed the court's order. It is not known when the appeal will be acted on by the Oklahoma Appellate court. Adjudication of the merits of Plaintiff's claims is stayed until the appeal of the class certification order is decided.

We continue to vigorously defend against each of the pending claims. At this time, we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or provide an estimate of potential losses, if any.

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

Our common stock trades on the New York Stock Exchange under the symbol "UNT." The high and low closing sales prices per share of our common stock can be easily accessed for free on numerous websites.

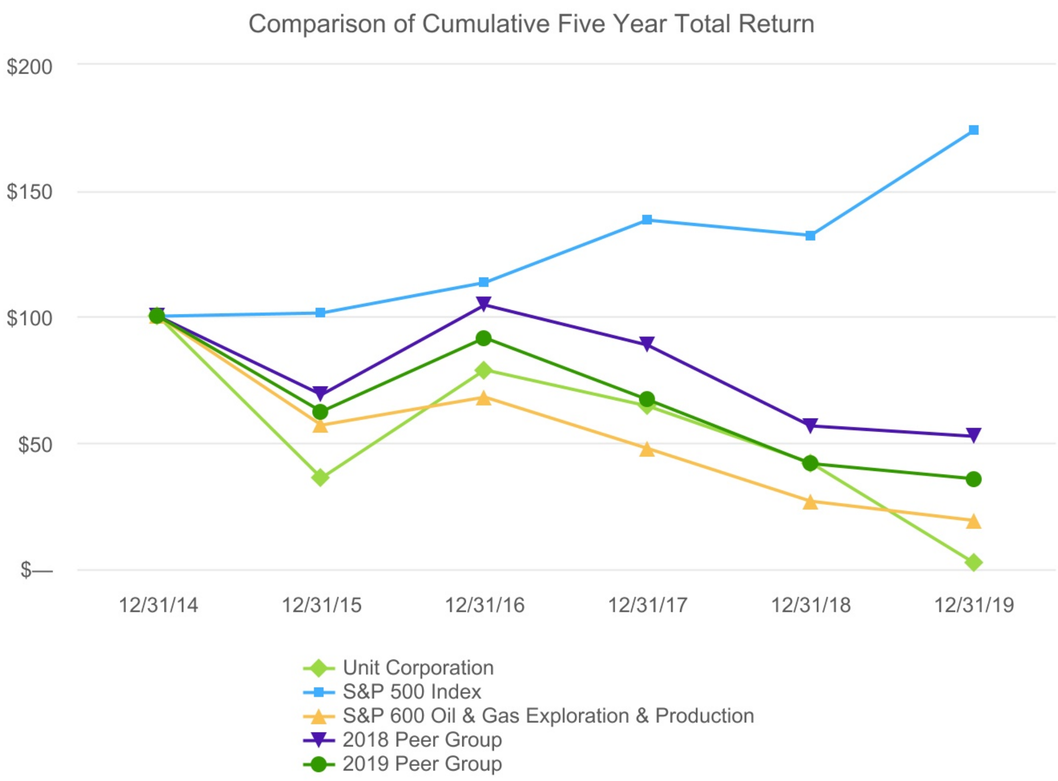
On February 28, 2020, the closing sale price of our common stock, as reported by the NYSE, was $0.35 per share. On that date, there were approximately 706 holders of record of our common stock.

On December 19, 2019, we were notified by the NYSE that we are not in compliance with the NYSE's continued listing requirements, as the average closing price of our 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 have six months following receipt of the notification to regain compliance with the minimum share price requirement. Our common stock will continue to be listed on the NYSE during this six month period, subject to compliance with other continued listing requirements. Our common stock symbol "UNT" has been assigned a ".BC" indicator by the NYSE to signify that we currently are not in compliance with the NYSE's continued listing requirements. If we fail to regain compliance with Section 802.01C during the cure period, our common stock will be subject to the NYSE's suspension and delisting procedures.

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. Our bank credit agreements and our senior subordinated notes 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 Senior Subordinated Notes" under Item 7 of this report.

Performance Graph. The following graph and related information shall not be deemed "soliciting material" or be deemed to be "filed" with the SEC, nor will this information be incorporated by reference into any future filing, except to the extent that we specifically incorporate it by reference into that filing.

Set forth below is a line graph comparing the cumulative total shareholder return on our common stock with the cumulative total return of the S&P 500 Stock Index, S&P 600 Oil and Gas Exploration & Production Index, and our executive compensation peer group. Our 2019 executive compensation peer group consisted of Carrizo Oil & Gas, Inc., Denbury Resources, Inc., Extraction Oil & Gas, Inc., Gulfport Energy Corporation, Helmerich & Payne, Inc., Laredo Petroleum, Inc., Oasis Petroleum, Inc., Patterson-UTI Energy, Inc., PDC Energy, Inc., Pioneer Energy Services Corp., Precision Drilling Corporation, SM Energy Company, SRC Energy, Inc., Whiting Petroleum Corporation and WPX Energy, Inc. The 2019 executive compensation peer group differs from our 2018 executive compensation peer group due to the removal of Cabot Corporation, Cimarex Energy Co, Newfield Exploration Company, and Parker Drilling Company (no longer considered suitable peers due to merger, bankruptcy, or corporate restructuring) and replacement with Extraction Oil & Gas, Inc., Gulfport Energy Corporation, Precision Drilling Corporation, and SRC Energy, Inc. (considered suitable replacement peers due to comparable business lines, market capitalization, or revenue size). The graph below assumes an investment of $100 at the beginning of the period. The shareholder return set forth below is not necessarily indicative of future performance.



Item 6. Selected Financial Data

The following table shows selected consolidated financial data. The data should be read in conjunction with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a review of 2019, 2018, and 2017 activity.

	As of and for the Year Ended December 31,				
	2019	2018	2017	2016	2015
	(In thousands except per share amounts)				
Revenues	$ 674,634	$ 843,281	$ 739,640	$ 602,177	$ 854,231
Net income (loss) attributable to Unit Corporation	$ (553,879) (4)	$ (45,288) (3)	$ 117,848	$ (135,624) (2)	$ (1,037,361) (1)
Net income (loss) attributable to Unit Corporation per common share:					
Basic	$ (10.48)	$ (0.87)	$ 2.31	$ (2.71)	$ (21.12)
Diluted	$ (10.48)	$ (0.87)	$ 2.28	$ (2.71)	$ (21.12)
Total assets	$ 2,090,052 (4)	$ 2,698,053 (3)	$ 2,581,452	$ 2,479,303 (2)	$ 2,799,842 (1)
Current portion of long-term debt	$ 108,200	$ —	$ —	$ —	$ —
Long-term debt [5]	$ 663,216	$ 644,475	$ 820,276	$ 800,917	$ 918,995
Other long-term liabilities [6]	$ 97,439	$ 101,527	$ 100,203	$ 103,479	$ 140,626
Cash dividends per common share	$ —	$ —	$ —	$ —	$ —

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1. In total for 2015, we incurred non-cash ceiling test write-downs on our oil and natural gas properties of $1.6 billion pre-tax ($1.0 billion, net of tax). We also incurred a non-cash write-down on certain drilling rigs and other equipment of approximately $8.3 million pre-tax ($5.1 million, net of tax), and a non-cash write-down associated with a reduction in the carrying value of three mid-stream segment systems of $27.0 million pre-tax ($16.8 million, net of tax).
2. For the first three quarters of 2016, we incurred non-cash ceiling test write-downs on our oil and natural gas properties of $161.6 million pre-tax ($100.6 million, net of tax).
3. In December 2018, we incurred a non-cash write-down associated with the removal of 41 drilling rigs from our fleet of $147.9 million pre-tax ($111.7 million, net of tax).
4. In the last two quarters of 2019, we incurred non-cash ceiling test write-downs on our oil and natural gas properties of $559.4 million pre-tax ($422.4 million, net of tax). We also incurred a goodwill impairment charge of $62.8 million, pretax ($59.8 million, net of tax).
5. Long-term debt is net of unamortized discount and debt issuance costs.
6. Includes operating lease liability and non-current derivative liabilities, if any.

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.

For discussion related to changes in financial condition and results of operations for 2018 as compared with 2017, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2018 Form 10-K, which was filed with the SEC on February 26, 2019.

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.

Business Outlook

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.

On March 9, 2020, the price of oil fell approximately 20% due to a dispute over production levels between Russia and Saudi Arabia, as a result of which Saudi Arabia increased its production to record levels. We cannot anticipate whether or when this dispute will be resolved and production returned to normalized levels. In the absence of a resolution, oil prices could remain at current levels, or decline further, for an extended period of time. As a result of record commodity price declines and our substantial debt burden, we do not believe that forecasted cash and available credit capacity will be sufficient to meet commitments as they come due over the next twelve months. Our ability to continue as a going concern is dependent on our ability to refinance our debt liability that is coming due. These factors, among others, raise substantial doubt about our ability to continue as a going concern. Our consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty. We cannot assure you that we will be successful in our efforts to generate revenues, become profitable, raise additional outside capital or to continue as a going concern. If we are not successful in our efforts to raise additional capital or to restructure our capital structure sufficient to support our operations, we would be unlikely to be able to raise capital in the near term and may be forced to seek protection under Chapter 11.

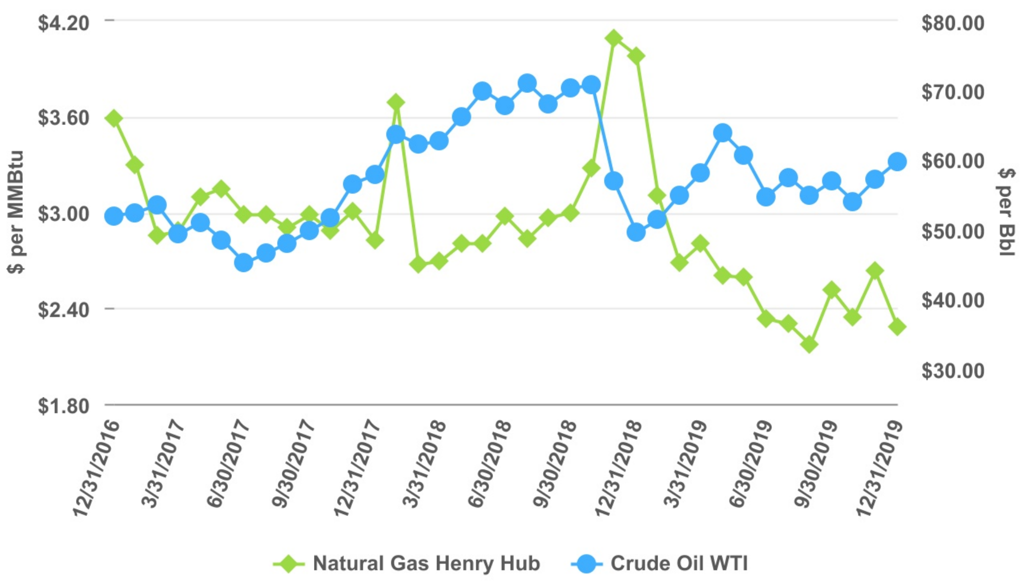
In an effort to address these circumstances, we sought to extend the maturity profile of our debt through the Exchange Offer. However, we have been advised by certain holders of a large percentage of our outstanding senior subordinated notes that they do not intend to participate in the Exchange Offer, which raises doubts regarding our ability to complete the Exchange Offer and increases the likelihood we may need to seek protection under Chapter 11.

Fluctuating commodity prices can result in significant changes to our industry and us. Depressed commodity prices, particularly for the extended time, can result in industry wide reductions in drilling activity and spending which reduce the rates for and the number of our drilling rigs we were able to put to work. Such industry wide reductions in drilling activity and spending for extended periods also reduces the rates for and the number of our drilling rigs we can work. In addition, sustained lower commodity prices impact the liquidity condition of some of our industry partners and customers, which could limit their ability to meet their financial obligations to us.

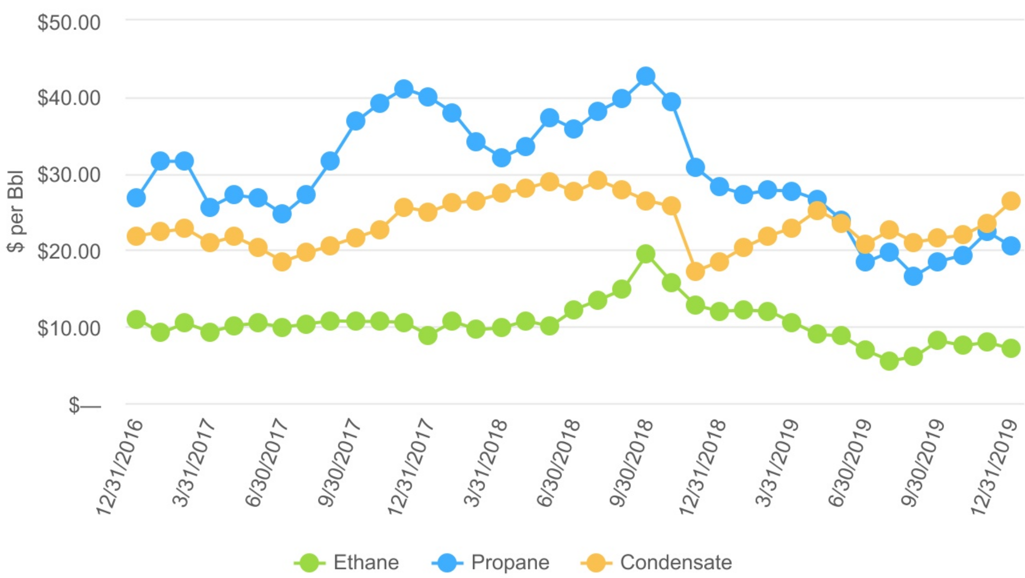
During the last three years, commodity prices have been volatile. Our oil and natural gas segment used two to three drilling rigs throughout 2017. With improved commodity prices during the first quarter of 2018, our oil and natural gas segment put four of our drilling rigs to work and increased the number to six drilling rigs for a brief period during the third quarter of

2018. We have subsequently reduced our operated rig count in the fourth quarter of 2018 and the first quarter of 2019 before getting as high as six drilling rigs again in the second quarter of 2019. Due to declining prices we shut down our drilling program in July and did not use any drilling rigs the remainder of the year.

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.

Commodity prices have continued to decline into the first quarter of 2020. As of March 11, 2020, crude oil WTI was $32.98 per BBl, natural gas Henry Hub was $1.88 per MMBtu, ethane was $5.87 per Bbl, propane was $13.05 per Bbl, and condensate was $14.50 per Bbl.

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). We anticipate a non-cash ceiling test write-down in the first quarter of 2020 and future quarters. It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, 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, 2019, and only adjust the 12-month average price to a first quarter ending average, our forward looking expectation is that we would recognize an impairment of $62 million pre-tax in the first quarter of 2020. The actual amount of any write-down may vary significantly from this estimate depending on the final future determination.

The number of gross wells our oil and gas segment drilled in 2019 verses 2018 decreased from 117 wells to 115 wells. For 2020, we do not currently have any plans to drill wells pending our ability to refinance our debt.

Our contract drilling segment completed the construction of three additional BOSS drilling rigs between the fourth quarter of 2016 and the third quarter of 2018. During the second quarter and third quarter of 2018, we were awarded term contracts to build our 12th and 13th BOSS drilling rigs. Construction was completed for one of these in January of 2019 and it was placed into service for a third-party operator. The other contract was terminated but we were able to find another third-party operator and the 13th BOSS drilling rig was placed into service in February of 2019. In the second half of 2019, we constructed the 14th BOSS drilling rig and it was placed into service in December 2019. Rig utilization fluctuated over the past year due to commodity prices changing and budget constraints on operators. We expect commodity prices and budget constraints on operators to continue to affect rig utilization throughout 2020. As of December 31, 2017, we had 31 drilling rigs operating. During 2018, utilization increased from 31 to a high of 36 drilling rigs and with a decline in commodity prices during the fourth quarter, declined to 32 drilling rigs as of December 31, 2018 and continued to decline to 20 drilling rigs as of December 31, 2019. As of December 31, 2019, all fourteen of our BOSS drilling rigs were operating.

During 2019, due to low ethane and residue prices, we operated some of our mid-stream processing facilities in ethane rejection mode which reduces the liquids sold. We are continuing to monitor commodity prices to determine the most economical method in which to operate our processing facilities.

Going Concern

As a result of the sustained commodity price decline and our substantial debt burden, we do not believe that we will be able to satisfy our commitments and debt repayments over the next twelve months. This conclusion is based on the following principal conditions which are explained in further detail below.

- Inability to meet anticipated commitments due to recurring losses, negative working capital and limited access to liquidity.
- A forecasted covenant violation of the Unit credit agreement for the quarter ending June 30, 2020.
- The expected acceleration of the amounts outstanding under the Unit credit agreement from October 18, 2023 to November 16, 2020.

The company has incurred significant losses and is in a negative working capital position at December 31, 2019. Additionally, our cash balance as of December 31, 2019 was $0.6 million and, effective January 17, 2020, the company's borrowing base under the Unit credit facility was reduced to $200.0 million of which $108.2 million has been borrowed. On March 11, 2020, the Company entered into a Standstill agreement with regards to the Unit credit facility which delays the scheduled borrowing base redetermination date for the facility from April 1, 2020 to April 15, 2020. Once the borrowing base is redetermined, the company anticipates that the borrowing base will be further reduced, potentially below the current amount outstanding under the credit facility. Such a reduction would prevent the company from further accessing the facility. Additionally, under the Standstill agreement, the company is prevented from withdrawing more than an additional $15.0 million between March 11, 2020 and the expiration of the agreement on April 15, 2020, which further reduces the company's ability to access liquidity during the term of the agreement. Due to our further anticipated losses, negative working capital position and lack of access to liquidity under the credit agreement, we do not anticipate that forecasted cash and available credit capacity will be sufficient to meet our commitments as they come due over the next twelve months.

Additionally, once the amounts outstanding on our 2021 Senior Notes are classified as current on our June 30, 2020 balance sheet, we will be in violation of the current ratio covenant in our credit agreement. If we are unable to cure the covenant violation, renegotiate the terms of the credit agreement or obtain a waiver, the covenant violation would result in all amounts outstanding under the Unit credit agreement becoming due and payable during the third quarter of 2020 (after we file our second quarter Form 10-Q). The covenant violation would also cause a cross-default of the indenture on our 2021 Senior Notes, which would make those notes immediately due and payable. The amounts outstanding as of December 31, 2019 on our Unit credit agreement and 2021 Senior Notes are $108.2 million and $650.0 million, respectively. If we are unable to avoid the anticipated credit violation or otherwise obtain a waiver, we will be unable to pay these amounts when due.

In addition, the October 18, 2023 scheduled maturity date of the loans under the Unit credit agreement will accelerate to November 16, 2020 to the extent that, on or before that date, all the 2021 Senior Notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023 (the "Credit Agreement Extension Condition"). On November 5, 2019, the company filed with the SEC a registration statement on Form S-4 (the Registration Statement) to commence an offer to exchange (the Exchange Offer) any and all of the existing 2021 Senior Notes for new notes with terms and conditions that would satisfy the Credit Agreement Extension Condition. However, there can be no assurance that the company will be able to complete the Exchange Offer as contemplated, if at all.

Due to the Credit Agreement Extension Condition, the company's debt associated with the Unit credit agreement is reflected as a current liability in its consolidated balance sheet as of December 31, 2019. The classification as a current liability is based on the uncertainty regarding the company's ability to repay or refinance the 2021 Senior Notes before November 16, 2020. Based on our current forecasted cash flows and cash on hand, we will not be able to pay the outstanding amount of the Unit credit agreement if the maturity is accelerated. Inability to pay the amount outstanding under the credit agreement would cause a covenant violation and also create cross-default with the indenture of the 2021 Senior Notes, which would also become due and payable. If we are unable to pay the balance of the Unit credit agreement upon acceleration, we would be required to file for protection under Chapter 11 of the U.S. Bankruptcy Code (Chapter 11).

Based on our evaluation of the conditions described above, substantial doubt exists about our ability to continue as a going concern. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

In order to alleviate the conditions that give rise to substantial doubt about our ability to continue as a going concern, the company is currently undertaking a number of actions, including (i) minimizing capital expenditures, (ii) aggressively managing working capital, (iii) further reducing recurring operating expenses, (iv) exploring potential business transactions, and (v) negotiating with existing debt holders to restructure existing debts. We believe that even after taking these actions, we will not have sufficient liquidity to satisfy our debt service obligations, meet other financial obligations, and comply with our debt covenants. We have engaged financial and legal advisors to, among other things, assist with analyzing various strategic alternatives, to include a potential reorganization under Chapter 11, to address our liquidity and capital structure. However, there can be no assurance that we will be able to restructure our financial obligations on terms acceptable to the company and our creditors, and there can be no assurance that we will generate the necessary liquidity to satisfy these obligations when they come due.

Executive Summary

Oil and Natural Gas

Fourth quarter 2019 production from our oil and natural gas segment was 4,157 MBoe, a decrease of 5% and 4% from the third quarter of 2019 and the fourth quarter of 2018, respectively. The decreases came from fewer net wells being completed in the fourth quarter to replace declines in previously drilled wells. Oil and NGLs production during the fourth quarter of 2019 was 48% of our total production compared to 46% of our total production during the fourth quarter of 2018.

Fourth quarter 2019 oil and natural gas revenues increased 7% over the third quarter of 2019 and decreased 21% from the fourth quarter of 2018. The increase over the third quarter of 2019 was primarily due an increase in commodity prices partially offset by a decrease in equivalent production. The decrease from the fourth quarter of 2018 was primarily due to a decrease in commodity prices and equivalent production.

Our hedged natural gas prices for the fourth quarter of 2019 increased 8% over third quarter of 2019 and decreased 29% from fourth quarter of 2018. Our hedged oil prices for the fourth quarter of 2019 increased 1% and 6% over the third quarter of 2019 and the fourth quarter of 2018, respectively. Our hedged NGLs prices for the fourth quarter of 2019 increased 54% over the third quarter of 2019 and decreased 33% from fourth quarter of 2018.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 24% over the third quarter of 2019 and decreased 29% from the fourth quarter of 2018. The increase over the third quarter of 2019 was primarily due to an increase in commodity prices and a reduction in lease operating expenses (LOE) and general and administrative (G&A) expenses partially offset by a decrease in equivalent production. The decrease from the fourth quarter of 2018 was primarily due to lower revenues due to lower commodity prices and volumes and higher salt water disposal expenses and gross production taxes.

Operating cost per Boe produced for the fourth quarter of 2019 decreased 8% from the third quarter of 2019 and increased 3% over the fourth quarter of 2018. The decrease from the third quarter of 2019 was primarily due to lower G&A and LOE. The increase over the fourth quarter of 2018 was primarily due to increased saltwater and production taxes along with lower equivalent production.

At December 31, 2019, these non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'20 - Dec'20	Natural gas - basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jan'20 - Dec'20	Natural gas - basis swap	20,000 MMBtu/day	$(0.455)	PEPL
Jan'21 - Dec'21	Natural gas - basis swap	30,000 MMBtu/day	$(0.215)	NGPL TEXOK
Jan'20 - Dec'20	Natural gas - three-way collar	30,000 MMBtu/day	$2.50 - $2.20 - $2.80	IF - NYMEX (HH)

In our Wilcox play, located primarily in Polk, Tyler, Hardin, and Goliad Counties, Texas, we completed seven vertical gas/condensate wells (average working interest 100%) in 2019. Annual production from our Wilcox play averaged 76 MMcfe per day (7% oil, 21% NGLs, 72% natural gas) which is a decrease of 15% compared to 2018. We averaged approximately 0.75 Unit drilling rigs operating during 2019.

In our Southern Oklahoma Hoxbar Oil Trend (SOHOT) play in western Oklahoma, primarily in Grady County, we completed seven horizontal oil wells in the Marchand zone of the Hoxbar interval and, in our Red Fork play, we completed seven horizontal wells. Average working interest for these wells was 85.3%. Annual production from western Oklahoma averaged 95.7 MMcfe per day (35% oil, 22% NGLs, 43% natural gas) which is an increase of approximately 25% compared to 2018. During 2019, we averaged approximately 1.5 Unit drilling rigs operating and we participated in 61 non-operated wells in the mid-continent region, with most of those occurring in the STACK play. Unit's average working interest in these non-operated wells is 3.7%.

In our Texas Panhandle Granite Wash play, we completed two extended lateral horizontal gas/condensate wells (average working interest 98.5%) in our Buffalo Wallow field. Annual production from the Texas Panhandle averaged 91.9 MMcfe per day (9% oil, 37% NGLs, 55% natural gas) which is a decrease of approximately 5% compared to 2018. We used 0.25 Unit drilling rigs during 2019.

In December of 2019, we sold our Panola Field in eastern Oklahoma for $17.9 million.

During 2019, we participated in the drilling of 115 wells (29.15 net wells). For 2020, we do not currently have any plans to drill wells pending our ability to refinance our debt.

Contract Drilling

The average number of drilling rigs we operated in the fourth quarter was 18.3 compared to 20.4 and 33.1 in the third quarter of 2019 and fourth quarter of 2018, respectively. As of December 31, 2019, 20 of our drilling rigs were operating.

Revenue for the fourth quarter of 2019 decreased 3% from the third quarter of 2019 and decreased 31% from the fourth quarter of 2018. The decreases were primarily due to less drilling rigs operating.

Dayrates for the fourth quarter of 2019 averaged $19,311, which was essentially unchanged from the third quarter of 2019 and a 7% increase over the fourth quarter of 2018. The increase over the fourth quarter of 2018 was primarily due to a labor increase passed through to contracted drilling rig rates and improving market dayrates and additional BOSS drilling rigs which receive higher dayrates.

Operating costs for the fourth quarter of 2019 decreased 8% from the third quarter of 2019 and decreased 26% from the fourth quarter of 2018. The decreases were both primarily due to less drilling rigs operating and from decreased employee cost in G&A expenses.

Direct profit (contract drilling revenue less contract drilling operating expense) for the fourth quarter of 2019 increased 15% over the third quarter of 2019 and decreased 41% from the fourth quarter of 2018. The increase over the third quarter of 2019 was primarily due to lower G&A expenses. The decrease from the fourth quarter of 2018 was primarily due to less drilling rigs operating.

Operating cost per day for the fourth quarter of 2019 increased 3% over the third quarter of 2019 and increased 34% over the fourth quarter of 2018. The increase over the third quarter of 2019 was primarily due to decreased eliminations with a lower percentage of our drilling rig usage coming from our oil and gas segment and higher third party expense. The increase over the fourth quarter of 2018 was primarily due to increased per day direct cost and total indirect and G&A expense spread over fewer operating days.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. Over the years 2014 through 2018, only six of our drilling rigs in the fleet had not been utilized. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer market based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax). During 2019, we sold six of these drilling rigs and some of the other equipment to unaffiliated third parties. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. Seven drilling rigs and equipment will be marketed for sale throughout the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.9 million.

The contract drilling segment has operations in Oklahoma, Texas, New Mexico, Wyoming, North Dakota, and to a lesser extent in Colorado. As of December 31, 2019, four drilling rigs were working in Oklahoma and the Texas Panhandle, seven in the Permian Basin of West Texas, one in New Mexico, two in Wyoming and six drilling rigs in the Bakken Shale of North Dakota.

During 2019, almost all of 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, 2019, we had 14 term drilling contracts with original terms ranging from two months to three years. Ten of these contracts are up for renewal in 2020, (three in the first quarter, three in the second quarter, one in the third quarter, and three in the fourth quarter) and four are up for renewal in 2021 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 $4.8 million, $0.1 million, and $0.8 million in early termination fees in 2019, 2018, and 2017, respectively.

All 14 of our existing BOSS drilling rigs are under contract.

All of our contracts are daywork contracts.

For 2020, we do not currently have an approved capital plan for this segment. Capital expenditures incurred would be within anticipated cash flows.

Mid-Stream

Fourth quarter 2019 liquids sold per day was essentially unchanged from the third quarter of 2019 and decreased 18% from the fourth quarter of 2018. The decrease from the fourth quarter of 2018 was due primarily to less processed volume from our processing systems along with operating in full ethane rejection. For the fourth quarter of 2019, gas processed per day decreased 3% from the third quarter of 2019 and increased 1% over the fourth quarter of 2018. The decrease from the third quarter of 2019 was primarily due to lower volume from the Hemphill Buffalo Wallow area. The increase over the fourth quarter of 2018 was due to connecting additional wells to our processing systems. For the fourth quarter of 2019, gas gathered per day decreased 7% from the third quarter of 2019 and increased 1% over the fourth quarter of 2018. The decrease from the third quarter of 2019 was primarily due to declining volumes from the Appalachian region and the increase over the fourth quarter of 2018 was primarily due to connecting the seven new wells on the Pittsburgh Mills gathering system.

NGLs prices in the fourth quarter of 2019 increased 19% over the prices received in the third quarter of 2019 and decreased 26% from the prices received in the fourth quarter of 2018. 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 2019 decreased 6% from the third quarter of 2019 and decreased 14% from the fourth quarter of 2018, respectively. The decrease from the third quarter of 2019 was primarily due to higher purchase prices partially offset by higher condensate volume. The decrease from the fourth quarter of 2018 was primarily due to lower NGL, gas and condensate prices along with lower NGLs and condensate volume. Total operating cost for this segment for the fourth quarter of 2019 increased 17% over the third quarter of 2019 and decreased 23% from the fourth quarter of 2018. The increase over the third quarter of 2019 was primarily due to an increase in gas purchase cost due to higher purchase prices. The decrease over the fourth quarter of 2018 was primarily due to lower gas purchase prices along with lower field direct operating expenses.

At the Cashion processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2019 averaged approximately 67.7 MMcf per day and total production of natural gas liquids increased to 326,337 gallons per day. We are continuing to connect new wells to this system from third party producers. Since the beginning of 2019, we have connected 35 new wells to this system from producers who continue to drill in the area. Construction of the 60 MMcf per day Reeding processing facility is complete and is fully operational. The total processing capacity on the Cashion system is 105 MMcf per day. With the assets from the recent acquisition in December, we will process the additional volume from these assets at the Reeding facility which is expected to begin April 1, 2020.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for December 2019 was 148.4 MMcf per day while the average gathered volume for the fourth quarter of 2019 was approximately 150.3 MMcf per day. During 2019, we added seven new wells to this system which accounted for a significant increase in gathered volume. Since these wells have been in production since the beginning of the year, we are seeing less of a decline than was expected from these wells. We are currently preparing to connect four new infill wells to this system which are expected to begin production in the second quarter of 2020.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the fourth quarter of 2019 was 62.2 MMcf per day and total production of natural gas liquids declined to 141,137 gallons per day due to lower wellhead volume and operating in full ethane rejection. Since the first of this year, we connected eight new wells to the Hemphill system. At this time there are no active rigs in the area and we have not budgeted 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 2019 was 59.9 MMcf per day. During 2019, we connected two new Unit Petroleum wells to this system. Unit Petroleum continues to rework and recomplete wells in the area around this system.

During the fourth quarter of 2019, we disposed of three small gathering systems. We sold the Scipio gathering system, which is located in Southeast Oklahoma, to the producer. There was no net book value and resulted in a small gain less than $0.1 million. We discontinued the operations and abandoned the Ford and Briscoe gathering systems and recorded an impairment on those assets of $0.8 million.

Also in December of 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 and the effective date of the purchase was December 1, 2019.

Anticipated 2020 capital expenditures for this segment will be approximately $28.0 million, a 57% decrease from 2019.

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 there is reasonable likelihood that materially different amounts could have been reported under different conditions, or had different assumption 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 attempt to 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.

This table lists the critical accounting policies, identifies the estimates and assumptions that can have a significant impact on applying these accounting policies, and the financial statement accounts affected by these estimates and assumptions.

Accounting Policies	**Estimates or Assumptions**	**Accounts Affected**
Full cost method of accounting for oil, NGLs, and natural gas properties	• Oil, NGLs, and natural gas reserves, estimates, and related present value of future net revenues • Valuation of unproved properties • Estimates of future development costs	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Impairment of oil and natural gas properties • Interest expense
Accounting for ARO for oil, NGLs, and natural gas properties	• Cost estimates related to the plugging and abandonment of wells • Timing of cost incurred • Credit adjusted risk free rate	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Current and non-current liabilities • Operating expense
Accounting for material producing property and undeveloped acreage acquisitions	• Value the reserves with the income approach using cash flow projections • Value the undeveloped acreage with the market approach using comparable sales data • Value equipment with the market approach using comparable sales data and CEPS pricing	• Oil and natural gas properties • Non-current liabilities
Accounting for impairment of long-lived assets	• Forecast of undiscounted estimated future net operating cash flows	• Oil and natural gas, drilling, and mid-stream property and equipment • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization
Goodwill	• Forecast of discounted estimated future net operating cash flows • Terminal value • Weighted average cost of capital	• Goodwill
Accounting for value of stock compensation awards	• Estimates of stock volatility • Estimates of expected life of awards granted • Estimates of rates of forfeitures • Estimates of performance shares granted	• Oil and natural gas properties • Shareholder's equity • Operating expenses • General and administrative expenses
Accounting for derivative instruments	• Derivatives measured at fair value	• Current and non-current derivative assets and liabilities • Gain (loss) on derivatives

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. The audit of our reserve wells or locations as of December 31, 2019 covered those that we projected to comprise 86% of the total proved developed future net income discounted at 10% (based on the SEC's unescalated pricing policy). 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.

As a rule, 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. Based on our 2019 production level of 16.8 MMBoe, a decrease in our 2019 oil, NGLs, and natural gas reserves by 5% would increase our DD&A rate by $0.54 per Boe and would decrease pre-tax income by $9.1 million annually. Conversely, an increase in our 2019 oil, NGLs, and natural gas reserves by 5% would decrease our DD&A rate by $0.48 per Boe and would increase pre-tax income by $8.1 million annually.

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, 2019, our reserves were calculated based on applying 12-month 2019 average unescalated prices of $55.69 per barrel of oil, $23.19 per barrel of NGLs, and $2.58 per Mcf of natural gas (then adjusted for price differentials) over the estimated life of each of our oil and natural gas properties. 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.

We anticipate a non-cash ceiling test write-down in the first quarter of 2020 and future quarters. It is hard to predict with any reasonable 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, 2019 and only adjust the 12-month average price to a first quarter ending average, our forward looking expectation is that we would recognize an impairment of $62 million pre-tax in the first quarter of 2020. Given the uncertainty associated with the factors used in calculating our estimate of both our future period ceiling test write-down and the removal of our undeveloped reserves, these estimates should not necessarily be construed as indicative of our future development plans or financial results and the actual amount of any write-down may vary significantly from this estimate depending on the final determination.

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. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. The expenses relating to the wells in which we have a production imbalance are not material.

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 and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. In 2017 and 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 and $10.5 million in 2019 and 2017, respectively of costs being added to the total of our capitalized costs being amortized. We did not have any in 2018. At December 31, 2019, we had approximately $252.9 million of costs excluded from the amortization base 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 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 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 current 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.

Accounting for Impairment of Long-Lived Assets. 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. 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 such an assessment may 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 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 amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates, and costs. Using different estimates and assumptions could cause materially different carrying values of our assets.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to 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 the Company's other marketed rigs are transferred to other rigs or to its yards to be spare equipment. The remaining components of these rigs are retired. No impairments were recorded in 2019 or 2017. In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer use based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax). During 2019, we sold six of these drilling rigs and some of the other equipment to unaffiliated third parties. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. Seven drilling rigs and equipment will be marketed for sale throughout the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.9 million.

During the third quarter of 2019, we determined a triggering event had occurred within our contract drilling reporting unit 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 the segment. Based on the results of the undiscounted future cash flows of the 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.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed 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, utilizing 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 reporting unit, 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 the total goodwill previously reported on our consolidated balance sheets. No goodwill impairment was recorded for the years ended December 31, 2018, or 2017.

Drilling Contracts. The type of contract used determines our compensation. All of our contracts in 2019, 2018, and 2017 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, among other things, 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.

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.

New Accounting 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. The amendment will be effective for reporting periods after December 15, 2019. We have evaluated the impact this will have on our consolidated financial statements by reviewing our accounts receivable accounts and our historic credit losses. This standard will not have a material impact on our financial statements.

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 will be effective for reporting periods beginning after December 15, 2019. Early adoption is permitted. Also, it is permitted to early adopt any removed or modified disclosure and delay adoption of the additional disclosures until their effective date. This amendment will not have a material impact on our financial statements.

Income Taxes (Topic 740)—Simplifying the Accounting for Income Taxes. The FASB issued ASU 2019-12 to reduce the cost and complexity related to the accounting for income taxes. The amendment will be effective for reporting periods beginning after December 15, 2020. Early adoption is permitted. We are evaluating what impact this standard will have on our consolidated financial statements.

Adopted Standards

Compensation—Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting. The FASB issued ASU 2018-07, to improve financial reporting for nonemployee share-based payments. The amendment expands Topic 718, *Compensation—Stock Compensation* to include share-based payments issued to nonemployees for goods or services. The amendment is effective for years beginning after December 15, 2018, and interim periods within those years. This amendment did not have an impact on our financial statements.

We adopted ASC 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 not adjusted and continue to be reported under the accounting standards in effect for those periods.

The additional disclosures required by ASC 842 have been included in Note 16 – Leases.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the measurement of goodwill. The amendment eliminates Step 2 from the goodwill impairment test. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019. We have early adopted this amendment in the third quarter of 2019. We performed our goodwill assessment and booked the impairment for the difference between fair value and book value.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity primarily depends 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 demand for and the dayrates we receive for our drilling rigs; and
- the fees and margins we obtain from our natural gas gathering and processing contracts.

Our financial statements have been prepared assuming we will continue as a going concern. As a result of the sustained commodity price decline and our substantial debt burden, we do not believe that forecasted cash and available credit capacity will be sufficient to meet commitments as they come due over the next twelve months. These conditions raise substantial doubt about our ability to continue as a going concern. Our ability to meet our debt covenants (under our credit agreements and our Indenture) and our capacity to incur additional indebtedness will depend on our future performance, which in turn will be affected by financial, business, economic, regulatory, and other factors.

Below is a summary of certain financial information for the years ended December 31:

	2019	2018	2017
		(In thousands)	
Net cash provided by operating activities	$ 269,396	$ 352,747	$ 270,088
Net cash used in investing activities	(394,563)	(450,342)	(293,366)
Net cash provided by financing activities	119,286	103,346	23,086
Net increase (decrease) in cash and cash equivalents	$ (5,881)	$ 5,751	$ (192)

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 quantity of oil, NGL, and natural gas we produce, settlements of derivative contracts, third-party demand 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 $83.4 million in 2019 compared to 2018 due primarily from lower revenues due to lower commodity prices and lower drilling rig utilization and by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital budget to the 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.

Cash flows used in investing activities decreased by $55.8 million in 2019 compared to 2018. The change was due primarily to a decrease in capital expenditures due to a decrease in wells drilled and oil and gas property acquisitions partially offset by the construction of new BOSS drilling rigs, acquisition of mid-stream assets, and an increase 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 financing activities increased by $15.9 million in 2019 compared to 2018. The increase was primarily due to an increase in the net borrowing under our credit agreements partially offset by the sale of 50% interest in our mid-stream segment in 2018.

At December 31, 2019, we had unrestricted cash totaling $0.6 million and had borrowed $108.2 million and $16.5 million of the amounts available under the Unit and Superior credit agreements, respectively.

Below is a summary of certain financial information as of December 31, and for the years ended December 31:

	2019		2018		2017	
	(In thousands)					
Working capital	$	(154,998)	$	(38,746)	$	(62,264)
Current portion of long-term debt	$	108,200	$	—	$	—
Long-term debt [(1)]	$	663,216	$	644,475	$	820,276
Shareholders' equity attributable to Unit Corporation [(2)]	$	853,878	$	1,390,881	$	1,345,560
Net income (loss) attributable to Unit Corporation [(2)]	$	(553,879)		(45,288)	$	117,848

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1. Long-term debt is net of unamortized discount and debt issuance costs.
2. In 2019, we incurred a 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). In 2018, we incurred a non-cash write-down associated with the removal of 41 drilling rigs from our fleet of $147.9 million pre-tax ($111.7 million, net of tax).

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 negative working capital of $155.0 million, $38.7 million, and $62.3 million as of December 31, 2019, 2018, and 2017, respectively. The decrease in working capital from 2018 is primarily due to the springing maturity of the Unit credit agreement, decreased cash and cash equivalents from the sale of 50% interest in our mid-stream segment in 2018, decreased accounts receivable due to decreased revenues, the change in the value of the derivatives outstanding, and the fair value of drilling assets held for sale partially offset by decreased accounts payable due to decreased activity in our drilling program. The Unit and Superior credit agreements are used primarily for working capital and capital expenditures. At December 31, 2019, we had borrowed $108.2 million of the $200.0 million available to us under the Unit credit agreement and $16.5 million of the $200.0 million available to us under the Superior credit agreement. The effect of our derivatives increased working capital by $0.6 million as of December 31, 2019, increased working capital by $12.9 million as of December 31, 2018, and decreased working capital by $7.1 million as of December 31, 2017.

This table summarizes certain operating information for the years ended December 31:

	2019	2018	2017
Oil and Natural Gas:			
Oil production (MBbls)	3,208	2,874	2,715
Natural gas liquids production (MBbls)	4,773	4,925	4,737
Natural gas production (MMcf)	53,065	55,626	51,260
Average oil price per barrel received	$ 57.49	$ 55.78	$ 49.44
Average oil price per barrel received excluding derivatives	$ 55.13	$ 63.78	$ 48.98
Average NGLs price per barrel received	$ 12.42	$ 22.18	$ 18.35
Average NGLs price per barrel received excluding derivatives	$ 12.42	$ 22.58	$ 18.35
Average natural gas price per mcf received	$ 2.04	$ 2.46	$ 2.46
Average natural gas price per mcf received excluding derivatives	$ 1.88	$ 2.42	$ 2.49
Contract Drilling:			
Average number of our drilling rigs in use during the period	24.6	32.8	30.0
Total drilling rigs available for use at the end of the period	58	55	95
Average dayrate	$ 18,762	$ 17,510	$ 16,256
Mid-Stream:			
Gas gathered—Mcf/day	435,646	393,613	385,209
Gas processed—Mcf/day	164,482	158,189	137,625
Gas liquids sold—gallons/day	625,873	663,367	534,140
Number of natural gas gathering systems	19	22	24
Number of processing plants	11	14	13

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.

Based on our 2019 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would cause a corresponding $423,000 per month ($5.1 million annualized) change in our pre-tax operating cash flow. Our 2019 average natural gas price was $2.04 compared to an average natural gas price of $2.46 for 2018 and $2.46 for 2017. A $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $252,000 per month ($3.0 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of derivatives, would have a $371,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow based on our production in 2019. Our 2019 average oil price per barrel was $57.49 compared with an average oil price of $55.78 in 2018 and $49.44 in 2017, and our 2019 average NGLs price per barrel was $12.42 compared with an average NGLs price of $22.18 in 2018 and $18.35 in 2017.

Because commodity prices affect the value of our oil, NGLs, and natural gas reserves, declines in those prices can cause a decline in the carrying value of our oil and natural gas properties. At December 31, 2019, the 12-month average unescalated prices were $55.69 per barrel of oil, $23.19 per barrel of NGLs, and $2.58 per Mcf of natural gas, and then are adjusted for price differentials. 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.

We anticipate a non-cash ceiling test write-down in the first quarter of 2020 and future quarters. It is hard to predict with any reasonable 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, 2019 and only adjust the 12-month average price to a first quarter ending average, our forward looking expectation is that we would recognize an impairment of $62 million pre-tax in the first quarter of 2020. Given the uncertainty associated with the factors used in calculating our estimate of both our future period ceiling test write-down and the removal of our undeveloped reserves, these estimates should not necessarily be construed as indicative of our future development plans or financial results and the actual amount of any write-down may vary significantly from this estimate depending on the final determination.

Our natural gas production is sold to intrastate and interstate pipelines, to independent marketing firms and gatherers under contracts with terms generally ranging from one month to five years. Our oil production is sold to independent marketing firms generally under six-month contracts.

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. We increased compensation for some rig personnel during the first quarter of 2018. 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 2019, almost all 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 2019, our average dayrate was $18,762 per day compared to $17,510 and $16,256 per day for 2018 and 2017, respectively. Our average number of drilling rigs used (utilization %) in 2019 was 24.6 (43%) compared with 32.8 (34%) and 30.0 (32%) in 2018 and 2017, respectively. Based on the average utilization of our drilling rigs during 2019, a $100 per day change in dayrates has a $2,460 per day ($0.9 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, $22.5 million, and $13.4 million during 2019, 2018, and 2017, respectively, from our contract drilling segment and eliminated the associated operating expense of $14.2 million, $19.5 million, and $11.8 million during 2019, 2018, and 2017, respectively, yielding $1.6 million, $3.0 million, and$1.6 million during 2019, 2018, and 2017, respectively, as a reduction to the carrying value of our oil and natural gas properties.

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, 19 gathering systems, and approximately 2,080 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 that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During 2019, 2018, and 2017 this segment purchased $40.6 million, $81.4 million, and $63.2 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $6.9 million, $7.3 million, and $6.7 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 435,646 Mcf per day in 2019 compared to 393,613 Mcf per day in 2018 and 385,209 Mcf per day in 2017. It processed an average of 164,482 Mcf per day in 2019 compared to 158,189 Mcf per day in 2018 and 137,625 Mcf per day in 2017, and sold NGLs of 625,873 gallons per day in 2019 compared to 663,367 gallons per day in 2018 and 534,140 gallons per day in 2017. Gas gathering volumes per day in 2019 increased primarily due to higher volumes at our Cashion and Pittsburgh Mills facilities. Volumes processed in 2019 increased due to connecting new wells to our processing facilities in 2019 primarily on the Cashion system. NGLs sold in 2019 decreased primarily due to lower NGL recoveries due to operating in full ethane rejection.

At-the-Market (ATM) Common Stock Program

On April 4, 2017, we entered into a Distribution Agreement (the Agreement) with a sales agent, under which we may offer and sell, from time to time, through the sales agent shares of our common stock, par value $0.20 per share (the Shares), up to an aggregate offering price of $100.0 million. We intended to use the net proceeds from these sales to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

On May 2, 2018, we terminated the Distribution Agreement. The Distribution Agreement was terminable at will on written notification by us with no penalty. As of the date of termination, we had sold 787,547 shares of our common stock under the Distribution Agreement resulting in net proceeds of approximately $18.6 million. We paid the sales agent a commission of 2.0% of the gross sales price per share sold. As a result of the termination, there will be no more sales of our common stock under the Distribution Agreement.

Our Credit Agreements and Senior Subordinated Notes

Unit Credit Agreement. Our Unit credit agreement is scheduled to mature on the earlier of (a) October 18, 2023, (b) November 16, 2020, to the extent that, on or before that date, all the Notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023, and (c) any earlier date on which the commitment amounts under the Unit credit agreement are reduced to zero or otherwise terminated.

Under the Unit credit agreement, the amount we can borrow is the lesser of the amount we elect as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $1.0 billion. Effective January 17, 2020, our elected commitment amount and borrowing base is $200.0 million. At December 31, 2019, we were charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. Total fees of $3.3 million in origination, agency, syndication, and other related fees are being amortized over the life of the Unit credit agreement. Under the agreement, we have pledged as collateral 80% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties. Pursuant to the mortgages covering such oil and gas properties, Unit Petroleum has also pledged as collateral certain items of its personal property.

On May 2, 2018, we entered into a Pledge Agreement with BOKF, NA (dba Bank of Oklahoma), as administrative agent to benefit the secured parties, granting a security interest in the limited liability membership interests and other equity interests we own in Superior (which as of this report is 50% of the aggregate outstanding equity interests of Superior) as additional collateral for our obligations under the Unit credit agreement.

The lenders under our Unit credit agreement and their respective participation interests are:

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17.060 %
BBVA Compass Bank	17.060 %
BMO Harris Financing, Inc.	15.294 %
Bank of America, N.A.	15.294 %
Comerica Bank	8.235 %
Toronto Dominion Bank, New York Branch	8.235 %
Canadian Imperial Bank of Commerce	8.235 %
Arvest Bank	3.529 %
Branch Banking & Trust	3.529 %
IBERIABANK	3.529 %
	100.000 %

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a one-time special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the Unit credit agreement. Effective January 17, 2020, our borrowing base was reduced from $275.0 million to $200.0 million.

At our election, any part of the outstanding debt under the Unit credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.50% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the Unit credit agreement that cannot be less than LIBOR plus 1.00% plus a margin. 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. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At December 31, 2019, we had $108.2 million outstanding borrowings.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets up to certain limits, (c) issuance of standby letters of credit, (d) contract drilling services and acquisition of contract drilling equipment, and (e) general corporate purposes.

The Unit credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year over 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions;
- the creation or existence of mortgages or liens, other than those in the ordinary course of business and with certain limited exceptions, on any of our properties, except in favor of our lenders; and
- investments in Unrestricted Subsidiaries (as defined in the Unit credit agreement) over $200.0 million.

The Unit credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the Unit credit agreement) of not less than 1 to 1.
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the Unit credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2019, we were in compliance with the covenants in the Unit credit agreement.

We have engaged in discussions with the lenders under the Unit credit agreement to enter into an amendment to the Unit credit agreement to, among other things, permit the issuance of the new Second Lien Senior Secured Notes (the New Notes), the incurrence of guarantees of the New Notes and the grant of liens securing the New Notes, each of which are currently not permitted under the Unit credit agreement. Due to the Credit Agreement Extension Condition, the company's debt associated with the Unit credit agreement is reflected as a current liability in its consolidated balance sheet as of December 31, 2019. The classification as a current liability is based on the uncertainty regarding the company's ability to repay or refinance the 2021 Senior Notes before November 16, 2020.

On March 11, 2020, we entered into a Standstill and Amendment Agreement (Standstill Agreement) with the lenders and administrative agent party to the Unit credit agreement. The Standstill Agreement, among other things, provides that during the standstill period (as defined below), the administrative agent and lenders under the Unit credit agreement agree to temporarily standstill from making any final determination in connection with the pending scheduled redetermination of the borrowing base that was, under the Unit credit agreement, otherwise scheduled to be made on or about April 1, 2020, and from otherwise exercising certain of their respective rights and remedies under the Unit credit agreement. The standstill period will begin after the effective date of the Standstill Agreement and will continue until the earlier of: (i) the receipt by any credit party from the administrative agent of notice of the occurrence of any termination event and (ii) 3:00 p.m. central time on April 15, 2020. "Termination event" is defined under the Standstill Agreement to include the occurrence of any one or more of the following: (i) any representation or warranty made or deemed to have been made by any credit party under the Standstill Agreement being false, misleading or erroneous in any material respect when made or deemed to have been made, (ii) any credit party failing to perform, observe or comply with any covenant, agreement or term contained in the Standstill Agreement in any material respect or (iii) any default which is not cured within five (5) business days or event of default occurring under the Unit credit agreement. Under the Standstill Agreement, we have agreed to limit our borrowings under the Unit credit agreement to $15.0 million, net of repayments.

The Standstill Agreement is expected to allow the parties to discuss proposals for addressing various credit matters, with a view to possibly entering into further modifications to the Unit credit agreement. We are currently engaged in discussions with respect to such credit matters; however, there can be no assurance that we will reach any agreement with respect to those matters by the end of the standstill period, if at all.

The above summary of the Unit credit agreement does not take into account the proposed amendments.

Superior Credit Agreement. On May 10, 2018, Superior, a limited liability company equally owned between us and SP Investor Holdings, LLC, 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) 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, among other things, 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. Additionally, the Superior credit agreement contains a number of 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, 2019, Superior was in compliance with the Superior credit agreement covenants.

The 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. As of December 31, 2019, we had $16.5 million outstanding borrowings under the Superior credit agreement.

Superior's credit agreement is not guaranteed by Unit.

The current lenders under the Superior credit agreement and their respective participation interests are:

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17.50 %
Compass Bank	17.50 %
BMO Harris Financing, Inc.	13.75 %
Toronto Dominion (New York), LLC	13.75 %
Bank of America, N.A.	10.00 %
Branch Banking and Trust Company	10.00 %
Comerica Bank	10.00 %
Canadian Imperial Bank of Commerce	7.50 %
	100.00 %

6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021. In issuing the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the 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 and providing for issuing the Notes. The Guarantors are our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no significant independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the 2011 Indenture. Effective April 3, 2018, Superior is no longer a Guarantor of the Notes. Excluding Superior, any of our other subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

We may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a "change of control" occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder's Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any,theron to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants including those that limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants under the 2011 Indentures as of December 31, 2019.

If an event of default occurs under the credit agreement that accelerates the maturity of at least $25.0 million of borrowings, it will cause a default under the 2011 Indenture which may in turn accelerate the maturity of the Notes.

On November 5, 2019, we filed with the SEC a registration statement on Form S-4 (the Registration Statement) regarding an offer to exchange (the Exchange Offer) any and all of our existing Notes for the New Notes, on the terms and conditions in the Registration Statement, and the related consent solicitation. The Registration Statement is not yet effective. See "Risk Factors—We may not complete the Exchange Offer and Consent Solicitation at all, or may complete the Exchange Offer with respect to less than all of our senior subordinated notes."

Capital Requirements

Oil and Natural Gas Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment 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. We completed drilling 115 gross wells (29.15 net wells) in 2019 compared to 117 gross wells (33.16 net wells) in 2018, and 70 gross wells (25.71 net wells) in 2017.

On April 3, 2017, we closed an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million. As of January 1, 2017, the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. This acquisition included 13 potential horizontal drilling locations not otherwise included in our existing acreage. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

In December 2018, we closed on an acquisition of certain oil and natural gas assets located primarily in Custer County, Oklahoma. The total preliminary adjusted value of consideration given was $29.6 million. As of November 1, 2018, the effective date of the acquisition, the estimated proved oil and gas reserves for the acquired properties was 2.6 MMBoe net to

Unit. The acquisition added approximately 8,667 net oil and gas leasehold acres to our Penn Sands area in Oklahoma including approximately 44 wells. Of the acreage acquired, approximately 82% was held by production.

Capital expenditures for oil and gas properties on the full cost method for 2019 by this segment, excluding a $0.1 million addition in the ARO liability and $3.7 million in acquisitions (including associated ARO), totaled $264.9 million compared to 2018 capital expenditures of $344.3 million (excluding a $7.6 million reduction in the ARO liability and $30.7 million in acquisitions), and 2017 capital expenditures of $215.4 million (excluding an $4.0 million reduction in the ARO liability and $59.0 million in acquisitions).

For 2020, we do not currently have any plans to drill wells pending our ability to refinance or restructure our debt.

We sold non-core oil and natural gas assets, net of related expenses, for $21.8 million, $22.5 million, and $18.6 million during 2019, 2018, and 2017, respectively. Proceeds from those dispositions reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling Dispositions, Acquisitions, and Capital Expenditures. During 2017, we built our tenth BOSS drilling rig and placed it into service for a third party operator under a long term contract. We also returned to service 14 SCR drilling rigs that had been previously stacked.

During 2018, we built our 11th BOSS drilling and placed it into service for a third party operator under a long term contract. We also made modifications to nine SCR rigs to meet customer requirements.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer use based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax). During 2019, we sold six of these drilling rigs and some of the other equipment to unaffiliated third parties. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. Seven drilling rigs and equipment will be marketed for sale throughout the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.9 million.

During 2019, we completed construction and placed into service with third party operators under long-term contracts our 12th and 13th BOSS drilling rigs. Our 14th BOSS drilling rig was completed and placed into service in December of 2019 for a third party operator under a long-term contract.

For 2020, we do not currently have an approved capital plan for this segment. Capital expenditures incurred would be within anticipated cash flows. We spent $40.6 million for capital expenditures during 2019 compared to $75.5 million in 2018, and $36.1 million in 2017.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. At the Cashion processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2019 averaged approximately 67.7 MMcf per day and total production of natural gas liquids increased to 326,337 gallons per day. We are continuing to connect new wells to this system from third party producers. Since the beginning of 2019, we have connected 35 new wells to this system from producers who continue to drill in the area. Construction of the 60 MMcf per day Reeding processing facility is complete and is fully operational. The total processing capacity on the Cashion system is 105 MMcf per day. With the assets from the recent acquisition in December, we will process the additional volume from these assets at the Reeding facility which is expected to begin April 1, 2020.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for December 2019 was 148.4 MMcf per day while the average gathered volume for the fourth quarter of 2019 was approximately 150.3 MMcf per day. During 2019, we added seven new wells to this system which accounted for a significant increase in gathered volume. Since these wells have been in production since the beginning of the year, we are seeing less of a decline than was expected from these wells. We are currently preparing to connect four new infill wells to this system which are expected to begin production in the second quarter of 2020.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the fourth quarter of 2019 was 62.2 MMcf per day and total production of natural gas liquids declined to 141,137 gallons per day due to lower wellhead volume and operating in full ethane rejection. Since the first of this year, we connected eight new wells to the Hemphill system. At this time there are no active rigs in the area and we have not budgeted 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 2019 was 59.9 MMcf per day. During 2019, we connected two new Unit Petroleum wells to this system. Unit Petroleum continues to rework and recomplete wells in the area around this system.

During the fourth quarter of 2019, we disposed of three small gathering systems. We sold the Scipio gathering system, which is located in Southeast Oklahoma, to the producer. There was no net book value and resulted in a small gain less than $0.1 million. We discontinued the operations and abandoned the Ford and Briscoe gathering systems and recorded an impairment on those assets of $0.8 million.

Also in December of 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 and the effective date of the purchase was December 1, 2019.

During 2019, our mid-stream segment incurred $64.4 million in capital expenditures which includes $16.1 million for an acquisition as compared to $44.8 million in 2018, and $22.2 million, in 2017. For 2020, our estimated capital expenditures will be approximately $28.0 million.

Contractual Commitments

At December 31, 2019, 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)		
Total debt [1]	$ 840,101	$ 156,173	$ 667,201	$ 16,727	$ —
Operating leases [2]	5,856	3,785	1,934	76	61
Finance lease interest and maintenance [3]	2,589	2,031	558	—	—
Drill pipe and equipment purchases [4]	909	909	—	—	—
Firm transportation commitments [5]	3,512	2,794	718	—	—
Total contractual obligations	$ 852,967	$ 165,692	$ 670,411	$ 16,803	$ 61

1. See previous discussion in MD&A regarding our debt. This obligation is presented under the Notes and the Unit and Superior credit agreements and includes interest calculated using our December 31, 2019 interest rates of 6.625% for the Notes and 4.0% for our Unit credit agreement and 3.9% for our Superior credit agreement. At December 31, 2019, our Unit credit agreement is reflected as a current liability in our consolidated balance sheet due to the uncertainty regarding the company's ability to repay or refinance the 2021 Senior Notes before November 16, 2020. The outstanding Unit credit agreement balance as of December 31, 2019 was $108.2 million. Our Superior credit agreement has a maturity date of May 10, 2023 and an outstanding balance of $16.5 million as of December 31, 2019.
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 2032. We also have short-term lease commitments of $0.4 million. This is lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; and Pinedale, Wyoming under the terms of operating leases expiring through October 2020. 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 $2.3 million and $0.3 million, respectively.
4. We have committed to purchase approximately $0.9 million of new drill pipe and equipment over the next year.
5. We have firm transportation commitments to transport our natural gas from various systems for approximately $2.8 million over the next twelve months and $0.7 million for the two years thereafter.

During the second quarter of 2018, as part of the Superior transaction, we entered into a contractual obligation that commits us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. This amount is included in our future drilling plans. For each dollar of the $150.0 million that we do not spend (over the three-year period), we would forgo receiving $0.58 of future distributions from our 50% ownership interest in our consolidated mid-stream subsidiary. At December 31, 2019, 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 $72.7 million. Total spent towards the $150.0 million as of December 31, 2019 was $24.7 million.

At December 31, 2019, we also had these commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	Estimated Amount of Commitment Expiration Per Period				
	(In thousands)				
Deferred compensation plan (1)	$ 6,180	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 10,122	$ 3,010	Unknown	Unknown	Unknown
ARO liability (3)	$ 66,627	$ 2,920	$ 44,758	$ 4,010	$ 14,939
Gas balancing liability (4)	$ 3,838	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (5)	$ 11,510	$ 4,393	$ 2,213	$ 948	$ 3,956
Finance lease obligations (6)	$ 7,379	$ 4,164	$ 3,215	$ —	$ —
Contract liability (7)	$ 7,061	$ 2,889	$ 4,137	$ 12	$ 23
Derivative liabilities—commodity hedges	$ 27	$ —	$ 27	$ —	$ —

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1. We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheets, at the time of deferral.
2. Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or with an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan (Special Plan). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company.
3. 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).
4. 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.
5. We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.
6. This amount includes commitments under finance lease arrangements for compressors in our mid-stream segment.
7. We have recorded a liability related to the timing of the revenue recognized on certain demand fees in our mid-stream segment.

Derivative Activities

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

Commodity Derivatives. Our commodity derivatives should 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, 2019, based on our fourth quarter 2019 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Mark-to-Market			
	2020			
	Q1	Q2	Q3	Q4
Daily natural gas production	21 %	21 %	21 %	21 %

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

Using derivative transactions has the risk that the counterparties may not meet their financial obligations under the transactions. Based on our evaluation at December 31, 2019, we believe the risk of non-performance by our counterparties is not material. At December 31, 2019, the fair values of the net assets we had with each of the counterparties to our commodity derivative transactions are:

	December 31, 2019
	(In millions)
Bank of Montreal	$ 0.4
Bank of America Merrill Lynch	0.2
Total net assets	$ 0.6

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, 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. At December 31, 2018, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $12.9 million and long-term derivative liabilities of $0.3 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) are as follows at December 31:

	2019	2018	2017
	(In thousands)		
Gain (loss) on derivatives, included are amounts settled during the period of $16,196, ($22,803),and $173, respectively	$ 4,225	$ (3,184)	$ 14,732

Stock and Incentive Compensation

During 2019, we granted awards covering 1,500,213 shares of restricted stock. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $22.6 million. Compensation expense will be recognized over the awards' three year vesting period. During 2019, we recognized $7.4 million in additional compensation expense and capitalized $1.4 million for these awards. During 2018, we granted awards covering 1,279,255 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over the awards' three year vesting period. During 2017, we granted awards covering 708,276 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over their two and three year vesting periods.

During 2019, we recognized compensation expense of $12.8 million for our restricted stock grants and capitalized $2.4 million of compensation cost for oil and natural gas properties.

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. Effective January 1, 2019, we elected to terminate and wind down all of the remaining employee limited partnerships at a repurchase cost of $0.6 million, net of Unit's interest. 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 are 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 were based on the related party's level of activity and were considered by us to be reasonable. During 2018 and 2017, the total we received for these fees was $0.2 million and $0.2 million, respectively. Our proportionate share of assets, liabilities, and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

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 our oil and natural gas properties. Commodity prices also can affect our fracking and completion costs and there has been downward pressure on these costs in the last half of 2019. 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

2019 versus 2018

	2019	2018	Percent Change [1]
	(In thousands unless otherwise specified)		
Total revenue	$ 674,634	$ 843,281	(20) %
Net loss	$ (553,828)	$ (39,767)	NM
Net income attributable to non-controlling interest	$ 51	$ 5,521	(99) %
Net loss attributable to Unit Corporation	$ (553,879)	$ (45,288)	NM
Oil and Natural Gas:			
Revenue	$ 325,797	$ 423,059	(23) %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 135,124	$ 131,675	3 %
Depreciation, depletion, and amortization	$ 168,651	$ 133,584	26 %
Impairment of oil and natural gas properties	$ 559,867	$ —	NM
Average oil price received (Bbl)	$ 57.49	$ 55.78	3 %
Average NGL price received (Bbl)	$ 12.42	$ 22.18	(44) %
Average natural gas price received (Mcf)	$ 2.04	$ 2.46	(17) %
Oil production (MBbls)	3,208	2,874	12 %
NGLs production (MBbls)	4,773	4,925	(3) %
Natural gas production (MMcf)	53,065	55,626	(5) %
Depreciation, depletion, and amortization rate (Boe)	$ 9.66	$ 7.50	29 %
Contract Drilling:			
Revenue	$ 168,383	$ 196,492	(14) %
Operating costs excluding depreciation	$ 115,998	$ 131,385	(12) %
Depreciation	$ 51,552	$ 57,508	(10) %
Impairment of goodwill	$ 62,809	$ —	NM
Impairment of contract drilling equipment	$ —	$ 147,884	(100) %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	24.6	32.8	(25) %
Average dayrate on daywork contracts	$ 18,762	$ 17,510	7 %
Mid-Stream:			
Revenue	$ 180,454	$ 223,730	(19) %
Operating costs excluding depreciation and amortization	$ 133,606	$ 167,836	(20) %
Depreciation and amortization	$ 47,663	$ 44,834	6 %
Impairment of gas gathering and processing equipment and line fill	$ 3,040	$ —	NM
Gas gathered—Mcf/day	435,646	393,613	11 %
Gas processed—Mcf/day	164,482	158,189	4 %
Gas liquids sold—gallons/day	625,873	663,367	(6) %
Corporate and other:			
General and administrative expense	$ 38,246	$ 38,707	(1) %
Other depreciation	$ 7,707	$ 7,679	— %
Gain (loss) on disposition of assets	$ (3,502)	$ 704	NM
Other income (expense):			
Interest income	$ 49	$ 972	95 %
Interest expense, net	$ (37,061)	$ (34,466)	8 %
Gain (loss) on derivatives	$ 4,225	$ (3,184)	NM
Other	$ (236)	$ 22	NM
Income tax benefit	$ (132,326)	$ (13,996)	NM
Average interest rate	6.4 %	6.5 %	(2) %
Average long-term debt outstanding	$ 744,978	$ 685,330	9 %

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 $97.3 million or 23% in 2019 as compared to 2018 due primarily to lower NGLs and natural gas prices and production partially offset by higher oil prices and production. Oil production increased 12%, NGLs production decreased 3%, and natural gas production decreased 5%. Average oil prices between the comparative years increased 3% to $57.49 per barrel, NGLs prices decreased 44% to $12.42 per barrel, and natural gas prices decreased 17% to $2.04 per Mcf.

Oil and natural gas operating costs increased $3.4 million or 3% between the comparative years of 2019 and 2018 primarily due to higher saltwater disposal expense and G&A expenses, partially offset by lower LOE.

DD&A increased $35.1 million or 26% primarily due to a 29% increase in our DD&A rate partially offset by an 1% decrease in equivalent production. The increase in our DD&A rate between periods resulted primarily from the cost of wells drilled in between the periods and decreased reserves due to lower prices.

During 2019, we recorded a non-cash ceiling test write-down 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 did not have a ceiling test write-down in 2018. We also recorded in 2019 a $0.5 million impairment on gathering systems with wells no longer producing.

Contract Drilling

Drilling revenues decreased $28.1 million or 14% in 2019 as compared to 2018. The decrease was due primarily to a 25% decrease in the average number of drilling rigs in use partially offset by a 7% increase in the average dayrate compared to 2018. Average drilling rig utilization decreased from 32.8 drilling rigs in 2018 to 24.6 drilling rigs in 2019.

Drilling operating costs decreased $15.4 million or 12% in 2019 compared to 2018. The decrease was due primarily to less drilling rigs operating partially offset by increased direct cost per day and increased indirect cost. Contract drilling depreciation decreased $6.0 million or 10% also due primarily to less drilling rigs operating and the transfer of 41 drilling rigs to assets held for sale at the end of 2018 partially offset by accelerated depreciation on drilling rigs stacked more than 49 months.

In 2019, we recognized goodwill impairment charges of $62.8 million, pre-tax ($59.8 million, net of tax) representing all of our goodwill which is related to our contract drilling segment. In 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer use based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax). During 2019, we sold six of these drilling rigs and some of the other equipment to unaffiliated third parties. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. Seven drilling rigs and equipment will be marketed for sale throughout the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.9 million.

Mid-Stream

Our mid-stream revenues decreased $43.3 million or 19% in 2019 as compared to 2018 primarily due to decreased NGLs, gas and condensate sales partially offset by higher transportation revenue. Gas processing volumes per day increased 4% between the comparative years due to connecting new wells to our processing systems. Gas gathering volumes per day increased 11% primarily due to connecting new wells at several of our gathering and processing systems.

Operating costs decreased $34.2 million or 20% in 2019 compared to 2018 primarily due to an decrease in purchase prices. Depreciation and amortization increased $2.8 million or 6% primarily due to placing additional capital assets into service in 2019.

The mid-stream segment had $3.0 million impairments due to decrease in value of line fill due to lower prices and from the retirement of two older systems.

General and Administrative

General and administrative expenses decreased $0.5 million or 1% in 2019 compared to 2018 primarily due to lower employee costs.

Gain (Loss) on Disposition of Assets

(Gain) loss on disposition of assets decreased $4.2 million in 2019 compared to 2018. The loss in 2019 was primarily from the retirement of old rig inventory, while the gain in 2018 was primarily for the sale of drilling equipment and vehicles.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $2.6 million between the comparative years of 2019 and 2018. 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. Capitalized interest for 2019 was $16.2 million compared to $16.5 million in 2018, and was netted against our gross interest of $53.2 million and $51.0 million for 2019 and 2018, respectively. Our average interest rate decreased from 6.5% to 6.4% and our average debt outstanding was $59.6 million higher in 2019 as compared to 2018 primarily due to the pay down of our Unit credit agreement in the second quarter of 2018.

Gain (loss) on derivatives increased $7.4 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 increased $118.3 million in 2019 compared to 2018. We recognized an income tax benefit of $132.3 million in 2019 compared to an income tax benefit of $14.0 million in 2018. The 2019 income tax benefit was higher primarily due to the larger pre-tax loss recognized in 2019 as compared to 2018.

Our effective tax rate was 19.3% for 2019 compared to 26.0% for 2018. The effective tax rate for the current year was lower as compared to 2018 because a substantial amount of the goodwill impairment was not deductible for income tax purposes as well as recording a valuation allowance of $19.7 million. The valuation allowance was due to determining it was more likely than not that the deferred tax asset for net operating loss carryforwards were not fully realizable. We paid $0.3 million in state income taxes during 2019 due to the sale of 50% interest in our mid-stream segment in 2018.

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 2019 production, a $0.10 per Mcf change in what we are paid for our natural gas production would cause a corresponding $423,000 per month ($5.1 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $252,000 per month ($3.0 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $371,000 per month ($4.5 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, 2019, these non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'20 - Dec'20	Natural gas - basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jan'20 - Dec'20	Natural gas - basis swap	20,000 MMBtu/day	$(0.455)	PEPL
Jan'21 - Dec'21	Natural gas - basis swap	30,000 MMBtu/day	$(0.215)	NGPL TEXOK
Jan'20 - Dec'20	Natural gas - three-way collar	30,000 MMBtu/day	$2.50 - $2.20 - $2.80	IF - NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreements and the Notes. The credit agreements, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreements may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in 2019, an 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $0.9 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 8. Financial Statements and Supplementary Data

Index to Financial Statements
Unit Corporation and Subsidiaries

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Unit Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Unit Corporation and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity, and cash flows for each of the three years in the period 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"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

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 Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements 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 audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 16, 2020

We have served as the Company's auditor since 1989.

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2019	2018
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 571	$ 6,452
Accounts receivable, net of allowance for doubtful accounts of $2,332 and $2,531 at December 31, 2019 and December 31, 2018, respectively	82,656	119,397
Materials and supplies	449	473
Current derivative asset (Note 14)	633	12,870
Current income taxes receivable	1,756	2,054
Assets held for sale (Note 3)	5,908	22,511
Prepaid expenses and other	13,078	6,602
Total current assets	105,051	170,359
Property and equipment:		
Oil and natural gas properties, on the full cost method:		
Proved properties	6,341,582	6,018,568
Unproved properties not being amortized	252,874	330,216
Drilling equipment	1,295,713	1,284,419
Gas gathering and processing equipment	824,699	767,388
Saltwater disposal systems	69,692	68,339
Corporate land and building	59,080	59,081
Transportation equipment	29,723	29,524
Other	57,992	57,507
	8,931,355	8,615,042
Less accumulated depreciation, depletion, amortization, and impairment	6,978,669	6,182,726
Net property and equipment	1,952,686	2,432,316
Goodwill (Note 3)	—	62,808
Right of use asset (Note 16)	5,673	—
Other assets	26,642	32,570
Total assets [(1)]	$ 2,090,052	$ 2,698,053

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (Continued)

	As of December 31, 2019	As of December 31, 2018
	(In thousands except share and par value amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 84,481	$ 151,686
Accrued liabilities (Note 7)	46,562	47,923
Current operating lease liability (Note 16)	3,430	—
Current portion of long-term debt (Note 8)	108,200	—
Current portion of other long-term liabilities (Note 8)	17,376	14,250
Total current liabilities	260,049	213,859
Long-term debt less debt issuance costs (Note 8)	663,216	644,475
Non-current derivative liabilities (Note 14)	27	293
Operating lease liability (Note 16)	2,071	—
Other long-term liabilities (Note 8)	95,341	101,234
Deferred income taxes (Note 10)	13,713	144,748
Commitments and contingencies (Note 17)	—	—
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $0.20 par value, 175,000,000 shares authorized, 55,443,393 and 54,055,600 shares issued as of December 31, 2019 and 2018, respectively	10,591	10,414
Capital in excess of par value	644,152	628,108
Accumulated other comprehensive loss (net of tax ($155) at December 31, 2018) (Note 19)	—	(481)
Retained earnings	199,135	752,840
Total shareholders' equity attributable to Unit Corporation	853,878	1,390,881
Non-controlling interests in consolidated subsidiaries	201,757	202,563
Total shareholders' equity	1,055,635	1,593,444
Total liabilities and shareholders' equity [1]	$ 2,090,052	$ 2,698,053

1. 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. Unit Corporation's consolidated total assets as of December 31, 2018 include current and long-term assets of its variable interest entity (VIE) (Superior) of $40.1 million and $423.3 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated total liabilities as of December 31, 2018 include current and long-term liabilities of the VIE of $42.8 million and $14.7 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. See Note 18 – Variable Interest Entity Arrangements.

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2019	2018	2017
	(In thousands except per share amounts)		
Revenues:			
Oil and natural gas	$ 325,797	$ 423,059	$ 357,744
Contract drilling	168,383	196,492	174,720
Gas gathering and processing	180,454	223,730	207,176
Total revenues	674,634	843,281	739,640
Expenses:			
Operating costs:			
Oil and natural gas	135,124	131,675	130,789
Contract drilling	115,998	131,385	122,600
Gas gathering and processing	133,606	167,836	155,483
Total operating costs	384,728	430,896	408,872
Depreciation, depletion, and amortization	275,573	243,605	209,257
Impairments (Note 3)	625,716	147,884	—
General and administrative	38,246	38,707	38,087
(Gain) loss on disposition of assets	3,502	(704)	(327)
Total operating expenses	1,327,765	860,388	655,889
Income (loss) from operations	(653,131)	(17,107)	83,751
Other income (expense):			
Interest, net	(37,012)	(33,494)	(38,334)
Gain (loss) on derivatives	4,225	(3,184)	14,732
Other	(236)	22	21
Total other income (expense)	(33,023)	(36,656)	(23,581)
Income (loss) before income taxes	(686,154)	(53,763)	60,170
Income tax expense (benefit):			
Current	(1,281)	(3,131)	5
Deferred	(131,045)	(10,865)	(57,683)
Total income taxes	(132,326)	(13,996)	(57,678)
Net income (loss)	(553,828)	(39,767)	117,848
Net income attributable to non-controlling interest	51	5,521	—
Net income (loss) attributable to Unit Corporation	$ (553,879)	$ (45,288)	$ 117,848
Net income (loss) attributable to Unit Corporation per common share (Note 6):			
Basic	$ (10.48)	$ (0.87)	$ 2.31
Diluted	$ (10.48)	$ (0.87)	$ 2.28

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

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

	For Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Net income (loss)	$ (553,828)	$ (39,767)	$ 117,848
Other comprehensive income (loss), net of taxes:			
Unrealized gain (loss) on securities, net of tax of $0, ($181), and $39	—	(557)	63
Reclassification adjustment for write-down of securities, net of tax of ($47), $0, and $0	481	—	—
Comprehensive income (loss)	(553,347)	(40,324)	117,911
Less: Comprehensive income attributable to non-controlling interest	51	5,521	—
Comprehensive income (loss) attributable to Unit Corporation	$ (553,398)	$ (45,845)	$ 117,911

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, 2017, 2018, and 2019

	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Loss	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	(In thousands except per share amounts)					
Balances, January 1, 2016	$ 10,016	$ 502,500	$ —	$ 681,554	$ —	$ 1,194,070
Net income	—	—	—	117,848	—	117,848
Other comprehensive income (net of tax $39)	—	—	63	—	—	63
Total comprehensive income						117,911
Proceeds from sale of stock (787,547 shares)	158	18,465	—	—	—	18,623
Activity in employee compensation plans (598,269 shares)	106	14,850	—	—	—	14,956
Balances, December 31, 2017	10,280	535,815	63	799,402	—	1,345,560
Cumulative effect adjustment for adoption of ASUs	—	—	13	(1,274)	—	(1,261)
Net income (loss)	—	—	—	(45,288)	5,521	(39,767)
Other comprehensive loss (net of tax ($181))	—	—	(557)	—	—	(557)
Total comprehensive loss						(40,324)
Contributions	—	102,958	—	—	197,042	300,000
Transaction costs associated with sale of non-controlling interest	—	(2,503)	—	—	—	(2,503)
Tax effect of the sale of non-controlling interest	—	(27,453)	—	—	—	(27,453)
Activity in employee compensation plans (1,175,466 shares)	134	19,291	—	—	—	19,425
Balances, December 31, 2018	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)
Reclassification adjustment for write-down of securities (net of tax ($47))	—	—	481	—	—	481
Total comprehensive loss						(553,347)
Distributions to non-controlling interest	—	—	—	—	(918)	(918)
Activity in employee compensation plans (1,387,793 shares)	177	16,044	—	—	61	16,282
Balances, December 31, 2019	$ 10,591	$ 644,152	$ —	$ 199,135	$ 201,757	$ 1,055,635

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
OPERATING ACTIVITIES:			
Net income (loss)	$ (553,828)	$ (39,767)	$ 117,848
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	275,573	243,605	209,257
Impairments (Note 3)	625,716	147,884	—
Amortization of debt issuance costs and debt discount (Note 8)	2,241	2,198	2,159
(Gain) loss on derivatives (Note 14)	(4,225)	3,184	(14,732)
Cash receipts (payments) on derivatives settled (Note 14)	16,196	(22,803)	173
(Gain) loss on disposition of assets	3,502	(704)	(327)
Deferred tax benefit (Note 10)	(131,045)	(10,865)	(57,683)
Employee stock compensation plans	12,932	22,899	17,747
Bad debt expense	527	81	348
ARO liability accretion (Note 9)	2,343	2,393	2,886
Contract assets and liabilities, net (Note 4)	(2,577)	(4,970)	—
Other, net	1,766	2,032	(865)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	33,323	(7,967)	(27,941)
Materials and supplies	24	32	2,835
Prepaid expenses and other	195	(4,950)	1,527
Accounts payable	(15,558)	28,013	8,192
Accrued liabilities	3,142	(5,465)	6,996
Income taxes	298	(1,993)	38
Contract advances	(1,149)	(90)	1,630
Net cash provided by operating activities	269,396	352,747	270,088
INVESTING ACTIVITIES:			
Capital expenditures	(406,665)	(446,282)	(255,553)
Producing property and other oil and natural gas acquisitions	(3,653)	(29,970)	(58,026)
Other acquisitions	(16,109)	—	—
Proceeds from disposition of property and equipment	31,864	25,910	21,713
Other	—	—	(1,500)
Net cash used in investing activities	(394,563)	(450,342)	(293,366)
FINANCING ACTIVITIES:			
Borrowings under line of credit	493,500	99,100	343,900
Payments under line of credit	(368,800)	(277,100)	(326,700)
Payments on finance leases	(4,001)	(3,843)	(3,694)
Proceeds from common stock issued, net of issue costs (Note 19)	—	—	18,623
Proceeds from investments in non-controlling interest	—	300,000	—
Employee taxes paid by withholding shares	(4,158)	(4,988)	(4,132)
Transaction costs associated with sale of non-controlling interest	—	(2,503)	—
Distributions to non-controlling interest	(918)	—	—
Bank overdrafts (Note 3)	3,663	(7,320)	(4,911)
Net cash provided by financing activities	119,286	103,346	23,086
Net increase (decrease) in cash and cash equivalents	(5,881)	5,751	(192)
Cash and cash equivalents, beginning of year	6,452	701	893
Cash and cash equivalents, end of year	$ 571	$ 6,452	$ 701

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

	Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$ 33,694	$ 34,535	$ 33,931
Income taxes	$ 273	$ 3,600	$ —
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	$ 54,549	$ (18,119)	$ (20,574)
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	$ (76)	$ 7,629	$ 3,613

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO 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 exploration, 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 principally 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 explore, 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 Arkansas, 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 our own account and for a wide range of other oil and natural gas companies. 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 – UNIT LIQUIDITY AND ABILITY TO CONTINUE AS A GOING CONCERN

As a result of the sustained commodity price decline and our substantial debt burden, we do not believe that we will be able to satisfy our commitments and debt repayments over the next twelve months. This conclusion is based on the following principal conditions which are explained in further detail below.

- Inability to meet anticipated commitments due to recurring losses, negative working capital and limited access to liquidity.
- A forecasted covenant violation of the Unit credit agreement for the quarter ending June 30, 2020.
- The expected acceleration of the amounts outstanding under the Unit credit agreement from October 18, 2023 to November 16, 2020.

The company has incurred significant losses and is in a negative working capital position at December 31, 2019. Additionally, our cash balance as of December 31, 2019 was $0.6 million and, effective January 17, 2020, the company’s borrowing base under the Unit credit facility was reduced to $200.0 million of which $108.2 million has been borrowed. On March 11, 2020, the Company entered into a Standstill agreement with regards to the Unit credit facility which delays the scheduled borrowing base redetermination date for the facility from April 1, 2020 to April 15, 2020. Once the borrowing base is redetermined, the company anticipates that the borrowing base will be further reduced, potentially below the current amount outstanding under the credit facility. Such a reduction would prevent the company from further accessing the facility. Additionally, under the Standstill agreement, the company is prevented from withdrawing more than an additional $15.0 million between March 11, 2020 and the expiration of the agreement on April 15, 2020, which further reduces the company’s ability to access liquidity during the term of the agreement. Due to our further anticipated losses, negative working capital position and lack of access to liquidity under the credit agreement, we do not anticipate that forecasted cash and available credit capacity will be sufficient to meet our commitments as they come due over the next twelve months.

Additionally, once the amounts outstanding on our 2021 Senior Notes are classified as current on our June 30, 2020 balance sheet, we will be in violation of the current ratio covenant in our credit agreement. If we are unable to cure the covenant violation, renegotiate the terms of the credit agreement or obtain a waiver, the covenant violation would result in all amounts outstanding under the Unit credit agreement becoming due and payable during the third quarter of 2020 (after we file our second quarter Form 10-Q). The covenant violation would also cause a cross-default of the indenture on our 2021 Senior Notes, which would make those notes immediately due and payable. The amounts outstanding as of December 31, 2019 on our

Unit credit agreement and 2021 Senior Notes are $108.2 million and $650.0 million, respectively. If we are unable to avoid the anticipated credit violation or otherwise obtain a waiver, we will be unable to pay these amounts when due.

In addition, the October 18, 2023 scheduled maturity date of the loans under the Unit credit agreement will accelerate to November 16, 2020 to the extent that, on or before that date, all the 2021 Senior Notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023 (the "Credit Agreement Extension Condition”). On November 5, 2019, the company filed with the SEC a registration statement on Form S-4 (the Registration Statement) to commence an offer to exchange (the Exchange Offer) any and all of the existing 2021 Senior Notes for new notes with terms and conditions that would satisfy the Credit Agreement Extension Condition. However, there can be no assurance that the company will be able to complete the Exchange Offer as contemplated, if at all.

Due to the Credit Agreement Extension Condition, the company's debt associated with the Unit credit agreement is reflected as a current liability in its consolidated balance sheet as of December 31, 2019. The classification as a current liability is based on the uncertainty regarding the company's ability to repay or refinance the 2021 Senior Notes before November 16, 2020. Based on our current forecasted cash flows and cash on hand, we will not be able to pay the outstanding amount of the Unit credit agreement if the maturity is accelerated. Inability to pay the amount outstanding under the credit agreement would cause a covenant violation and also create cross-default with the indenture of the 2021 Senior Notes, which would also become due and payable. If we are unable to pay the balance of the Unit credit agreement upon acceleration, we would be required to file for protection under Chapter 11 of the U.S. Bankruptcy Code (Chapter 11).

Based on our evaluation of the conditions described above, substantial doubt exists about our ability to continue as a going concern. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

In order to alleviate the conditions that give rise to substantial doubt about our ability to continue as a going concern, the company is currently undertaking a number of actions, including (i) minimizing capital expenditures, (ii) aggressively managing working capital, (iii) further reducing recurring operating expenses, (iv) exploring potential business transactions, and (v) negotiating with existing debt holders to restructure existing debts. We believe that even after taking these actions, we will not have sufficient liquidity to satisfy our debt service obligations, meet other financial obligations, and comply with our debt covenants. We have engaged financial and legal advisors to, among other things, assist with analyzing various strategic alternatives, to include a potential reorganization under Chapter 11, to address our liquidity and capital structure. However, there can be no assurance that we will be able to restructure our financial obligations on terms acceptable to the company and our creditors, and there can be no assurance that we will generate the necessary liquidity to satisfy these obligations when they come due.

NOTE 3 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. Our investment in limited partnerships is accounted for on the proportionate consolidation method, whereby our share of the partnerships’ assets, liabilities, revenues, and expenses are included in the appropriate classification in the accompanying consolidated financial statements. We consolidate the activities of Superior, a 50/50 joint venture between Unit Corporation 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, through 50% ownership, to direct those activities that most significantly affect the economic performance of Superior as further described in Note 18 – Variable Interest Entity Arrangements.

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to current year presentations. Certain financial statement captions were expanded or combined with no impact to consolidated net income or shareholders' equity.

Accounting Estimates. The preparation of 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. We recognize revenues and expenses generated from "daywork” drilling contracts as the services are performed, since we do not bear the risk of completion of the well. 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, 2019, all of our contracts were daywork contracts of which 14 were multi-well and had durations which ranged from two months to three years, 10 of which expire in 2020 and four expiring in 2021 and beyond. 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 that have been issued before the end of the period, but not presented to our bank for payment before the end of the period. At December 31, 2019 and 2018, bank overdrafts were $8.7 million and $5.1 million, respectively.

Accounts Receivable. Accounts receivable are 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 receivables. Our credit risk is considered to be limited due to the large number of customers comprising our customer base. Below are the third-party customers that accounted for more than 10% of our segment's revenues:

	2019	2018	2017
Oil and Natural Gas:			
CVR Refining, LP	14 %	14 %	2 %
Valero Energy Corporation	9 %	10 %	9 %
Energy Transfer Partners (formerly Sunoco Logistics Partners)	5 %	3 %	10 %
Drilling:			
EOG Resources, Inc.	12 %	5 %	— %
QEP Resources, Inc.	12 %	16 %	26 %
Slawson Exploration Company, Inc	11 %	10 %	6 %
Mid-Stream:			
ONEOK, Inc.	33 %	45 %	36 %
Range Resources Corporation	13 %	7 %	9 %
Centerpoint Energy Service, Inc.	10 %	5 %	4 %

We had a concentration of cash of $1.7 million and $11.0 million at December 31, 2019 and 2018, respectively with one bank.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties and our own non-performance risk in our derivative valuation at December 31, 2019 and determined there was no material risk at that time. At December 31, 2019, the fair values of the net assets (liabilities) we had with each of the counterparties with respect to all of our commodity derivative transactions are listed in the table below:

	December 31, 2019
	(In millions)
Bank of Montreal	$ 0.4
Bank of America Merrill Lynch	0.2
Total net assets	$ 0.6

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. Depreciation of drilling equipment is recorded 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, except when idle for greater than 48 months, then it will be depreciated at the full active rate. We use the composite method of depreciation for drill pipe and collars and calculate the depreciation by footage actually drilled compared to total estimated remaining footage. 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 that these carrying amounts may not be recoverable. Changes that could prompt such an assessment may 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 amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates, and costs. The use of different estimates and assumptions could cause materially different carrying values of our assets.

During the third quarter of 2019, we determined a triggering event had occurred within our contract drilling reporting unit 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 the segment. Based on the results of the undiscounted future cash flows of the 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.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to 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 the company's other marketed rigs are transferred to other rigs or to its yards to be used as spare equipment. The remaining components of these rigs are retired. In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer use based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax), the fair value of the assets held for sale at December 31, 2019 is $5.9 million. These assets include seven drilling rigs and equipment that will be marketed for sale throughout the next twelve months. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. Our contract drilling segment had no impairments in either 2019 or 2017. 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.

We record an asset and a liability equal to the present value of the expected future ARO associated with our oil and gas properties. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by accreting an interest charge. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense.

Capitalized Interest. During 2019, 2018, and 2017, interest of approximately $16.2 million, $16.5 million, and $15.9 million, respectively, was capitalized 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. Interest is being capitalized using a weighted average interest rate based on our outstanding borrowings.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed 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, utilizing 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 reporting unit, 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 the total goodwill previously reported on our consolidated balance sheets. No goodwill impairment was recorded for the years ended December 31, 2018, or 2017. There were no additions to goodwill in 2019, 2018, or 2017.

Oil and Natural Gas Operations. We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, 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, are capitalized and amortized on a units-of-production method based on proved oil and natural gas reserves. Directly related overhead costs of $16.5 million, $15.9 million, and $14.8 million were capitalized in 2019, 2018, and 2017, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average rates used for DD&A were $9.66, $7.50, and $6.00 per Boe in 2019, 2018, and 2017, respectively. 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. Our unproved properties and wells in progress totaling $252.9 million are excluded from the DD&A calculation.

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 as well as the substantial doubt that exists 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.

Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. We 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. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

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 and $10.5 million in 2019 and 2017, respectively of costs being added to the total of our capitalized costs being amortized. We did not have any in 2018. 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. We had no non-cash ceiling test write-downs during 2017 or 2018.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on the timing of the drilling services performed on our properties those services may be deemed, for financial reporting purposes, to be associated with the acquisition of 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 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 revenue of $15.8 million, $22.5 million, and $13.4 million during 2019, 2018, and 2017, respectively, from our contract drilling segment and eliminated the associated operating expense of $14.2 million, $19.5 million, and $11.8 million during 2019, 2018, and 2017, respectively, yielding $1.6 million, $3.0 million, and$1.6 million during 2019, 2018, and 2017, respectively, as a reduction to the carrying value of our oil and natural gas properties.

ARO. 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 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 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 current 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.

Gas Gathering and Processing Revenue. Our gathering and processing segment recognizes revenue from the gathering and processing of natural gas and NGLs in the period the service is provided based on contractual terms.

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 in order 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 with the exception of normal purchase and normal sales which are expected to result in physical delivery. 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.

We document our risk management strategy and do not engage in derivative transactions for speculative purposes.

Limited Partnerships. Unit Petroleum Company was a general partner in 13 oil and natural gas limited partnerships sold privately and publicly. Some of our officers, directors, and employees owned the interests in most of these partnerships. We shared in each partnership's revenues and costs in accordance with formulas set out in each of 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. During the fourth quarter of 2017, the U.S. government enacted the Tax Act. Among other provisions, the Tax Act reduces the federal corporate tax rate from the existing maximum rate of 35% to 21%, effective January 1, 2018. The change in tax law required the company to remeasure existing net deferred tax liabilities using the lower rate in the period of enactment resulting in the company recording a tax benefit of $81.3 million in 2017. Measurement of net deferred tax liabilities is based on provisions of enacted tax law (including the 2017 Tax Act); the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary 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 its share of pro-rata production from certain wells. We estimate our December 31, 2019 balancing position to be approximately 3.4 Bcf on under-produced properties and approximately 3.5 Bcf on over-produced properties. We have recorded a receivable of $3.6 million on certain wells where we estimate that insufficient reserves are available for us to recover the under-production from future production volumes. We have also recorded a liability of $3.8 million on certain properties where we believe 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 in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The amount of 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 utilize the Black-Scholes option pricing model to measure the fair value of stock options and SARs. The value of our restricted stock grants is based on the closing stock price on the date of the grants.

New Accounting 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. The amendment will be effective for reporting periods after December 15, 2019. We have evaluated the impact this will have on our consolidated financial statements by reviewing our accounts receivable accounts and our historic credit losses. This standard will not have a material impact on our financial statements.

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 will be effective for reporting periods beginning after December 15, 2019. Early adoption is permitted. Also, it is permitted to early adopt any removed or modified disclosure and delay adoption of the additional disclosures until their effective date. This amendment will not have a material impact on our financial statements.

Income Taxes (Topic 740)—Simplifying the Accounting for Income Taxes. The FASB issued ASU 2019-12 to reduce the cost and complexity related to the accounting for income taxes. The amendment will be effective for reporting periods beginning after December 15, 2020. Early adoption is permitted. We are evaluating what impact this standard will have on our consolidated financial statements.

Adopted Standards

Compensation—Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting. The FASB issued ASU 2018-07, to improve financial reporting for nonemployee share-based payments. The amendment expands Topic 718, *Compensation—Stock Compensation* to include share-based payments issued to nonemployees for goods or services. The amendment is effective for years beginning after December 15, 2018, and interim periods within those years. This amendment did not have an impact on our financial statements.

We adopted ASC 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 not adjusted and continue to be reported under the accounting standards in effect for those periods.

The additional disclosures required by ASC 842 have been included in Note 16 – Leases.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the measurement of goodwill. The amendment eliminates Step 2 from the goodwill impairment test. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019. We have early adopted this amendment in the third quarter of 2019. We performed our goodwill assessment and booked the impairment for the difference between fair value and book value.

NOTE 4 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Our revenue streams are reported under 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 time 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 mid-stream and downstream oil and gas companies.

We satisfy the performance obligation under each segment's contracts as follows: for the contract drilling and mid-stream contracts, we satisfy the performance obligation over the agreed-on time within the contracts, and for oil and natural gas contracts, we satisfy the performance obligation with each delivery of volumes. 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 on number of days following the end of the month. Besides the mid-stream demand 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 segments are Oil Sales Contracts, Gas Purchase Agreements, 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 term can range from a single month to a term spanning a decade or more; some may also include evergreen provisions. Revenues from sales we make are recognized when our customer obtains control of the sold product. For sales to other mid-stream and downstream oil and gas companies, this would occur at a point in time, typically 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 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 separately identifiable since each delivery provides benefits to the customer on its own. 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 which includes payment for all deliveries in that month. Depending on contract circumstances, judgment could be required to determine when the transfer of control occurs. Generally, depending of the facts and circumstances, we consider the transfer of control of the asset in a commodity sale to occur at the point the commodity transfers to our purchaser.

Most of the consideration received by us for oil and gas sales is variable. Most of our contracts state the consideration is calculated by multiplying a variable quantity by an agreed-on index price less deductions related to gathering, transportation, fractionation, and related fuel charges. There are also instances where the consideration is quantity multiplied by a weighted average sales price. These different pricing tools can change the perception of when control transfers; however, when analyzed with other control factors, typically the accounting conclusion is the same for both pricing methods. In these instances, the variable consideration is partially constrained. In addition, all variable consideration is settled at the end of the month; therefore, whether the variability is constrained does not affect accounting for revenue under ASC 606 as the variability is known prior to 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 contracts our drilling segment uses are primarily industry standard IADC contracts model year 2003 and 2013. Contract terms range from two months to three or more years or 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 will be 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)). Allocation rules under this new standard allow us to recognize revenues associated with our drilling contacts in materially the same manner as under 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 will be amortized over the recognition period based on the same method of measure used for revenue. On adoption of the standard, no adjustment to opening retained earnings was required.

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, which we have concluded will not apply to our contracts as of the reporting date. 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, 2019, we had 21 contract drilling contracts (14 of which are term contracts) for a duration of two months to three years.

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). The majority of our drilling contracts have an original term of less than one year; however, the remaining performance obligations under the contracts that have 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. The typical revenue contracts used by this segment are gas gathering and processing agreements. Contract terms range from a single month to terms spanning a decade or more, some include evergreen provisions. Fees for mid-stream services (gathering, transportation, processing) are performance obligations and meet the criteria of over time recognition which could be considered a series of distinct performance obligations that represents one overall performance obligation of gas gathering and processing services.

Included below is the additional fixed revenue we will earn over the remaining term of the contracts and excludes all variable consideration to be earned with the associated contract as of December 31, 2019.

Contract	Remaining Term of Contract	2020	2021	2022	2023 and beyond	Total Remaining Impact to Revenue
Demand fee contracts	3-9 years	$ (3,775)	$ (3,501)	$ 1,380	36	$ (5,860)

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, as the demand fee does not specifically relate to a distinct performance obligation, under the new standard that amount should now 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 will be recognized over the remaining term of the contract. As this amount is fixed, recognition of the remaining portion will be stable. Besides the demand fee, there were no other contract assets or liabilities (see above for the balance sheet line items where they are reported). Revenue recognized for these demand fees was \$2.6 million and \$5.0 million in 2019 and 2018, respectively.

	December 31, 2019	December 31, 2018	Change
	(In thousands)		
Contract assets	\$ 12,921	\$ 13,164	\$ (243)
Contract liabilities	7,061	9,881	(2,820)
Contract assets (liabilities), net	\$ 5,860	\$ 3,283	\$ 2,577

Our performance obligations for all contracts is to gather, transport, or process an agreed-on number of volumes as stated in the contract. Typically, the contract will establish a period over which the company will perform the mid-stream services. Certain contracts also include an agreed-on quantity (or an agreed-on minimum quantity) of volumes that the company will deliver or service. The term under mid-stream service contracts is typically five to ten years. Under service contracts, as the customer simultaneously receives and consumes the benefits provided by the entity's performance as the entity performs, the performance obligation to gather, transport, or process occurs over time. We typically receive payment within a set number of days following the end of the month and includes payment for all services performed that month. Our overall performance obligation is satisfied at the end of the contract term.

Most of the consideration received under mid-stream service contracts is variable. The consideration is calculated by multiplying a variable quantity (number of volumes) by an agreed-on price per MCF (commodity fee and the gathering fee). One fixed component of revenue is calculated by multiplying an agreed-on price by a certain volume commitment (MCF per day). Other revenue items may include shortfall fees. All variable consideration is settled at the end of the month; therefore, whether or not the variability is constrained does not affect accounting for revenue under ASC 606 as the variability is known before each reporting period. However, this excludes the shortfall fee as this fee could be based on a set number of volumes over the course of more than one month.

Per the new guidance related to disclosures for 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). There is also a practical expedient for "variable consideration [that] is allocated entirely to a wholly unsatisfied performance obligation… that forms part of a single performance obligation… for which the criteria in paragraph 606-10-32-40 have been met" (ASC 606-10-50-14A). As stated previously, the contract term for mid-stream services is typically longer than one year. However, based on the guidance at 606-10-32-40, we determined some of the variable payment in mid-stream service agreements specifically relates to the entity's efforts to satisfy the performance obligation and that "allocating the variable amount entirely to the distinct good or service is consistent with the allocation objective in paragraph 606-10-32-28." Therefore, the practical expedient relates to this variable consideration: the commodity fee and the gathering fee. The last time we received a shortfall fee was in 2016 and the amount was immaterial to total mid-stream revenues. These terms have historically been limited in our contracts.

We calculate revenue earned from the variable consideration related to mid-stream services by multiplying the number of volumes serviced times an agreed-on price. Therefore, the variable portion of this consideration is due to the change in volumes. This variability is resolved at the end of each month as the company will know the number of volumes serviced under each contract and payment is received monthly. The mid-stream gathering service contracts remaining are for a duration of less than one year to 15 years.

While long term service contracts are in place as of the reporting date, due to the variable volumes an estimation and allocation of transaction price and future obligations are not required.

NOTE 5 – ACQUISITIONS AND DIVESTITURES

Acquisitions

Oil and Natural Gas

On April 3, 2017, we closed on an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was \$54.3 million.

As of January 1, 2017, the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

We accounted for this acquisition using the acquisition method under ASC 805, *Business Combinations*, which requires that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the final adjusted purchase price and the values of assets acquired and liabilities assumed.

Final Adjusted Purchase Price		
Total consideration given	$	54,332
Final Adjusted Allocation of Purchase Price		
Oil and natural gas properties included in the full cost pool:		
Proved oil and natural gas properties	$	43,745
Undeveloped oil and natural gas properties		8,650
Total oil and natural gas properties included in the full cost pool [1]		52,395
Gas gathering equipment and other		2,340
Asset retirement obligation		(403)
Fair value of net assets acquired	$	54,332

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2. We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates.

The pro forma effects of this acquired business are immaterial to the results of operations.

For 2017, we had approximately $4.7 million in other acquisitions.

In December 2018, we closed on an acquisition of certain oil and natural gas assets located primarily in Custer County, Oklahoma. The total adjusted value of consideration given was $29.6 million As of November 1, 2018, the effective date of the acquisition, the estimated proved oil and gas reserves for the acquired properties was 2.6 MMBoe net to Unit. The acquisition added approximately 8,667 net oil and gas leasehold acres to our Penn Sands area in Oklahoma including approximately 44 wells. The acquisition included approximately 30 potential horizontal drilling locations which are anticipated to have a high percentage of oil relative to the total production stream. Of the acreage acquired, approximately 82% was held by production.

We accounted for this acquisition using the acquisition method under ASC 805, *Business Combinations*, which requires that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the final adjusted purchase price and the values of assets acquired and liabilities assumed.

Purchase Price		
Total consideration given	$	29,633
Allocation of Purchase Price		
Oil and natural gas properties included in the full cost pool:		
Proved oil and natural gas properties	$	14,546
Undeveloped oil and natural gas properties		15,502
Total oil and natural gas properties included in the full cost pool [1]		30,048
Asset retirement obligation		(415)
Fair value of net assets acquired	$	29,633

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1. We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates.

The pro forma effects of this acquired business are immaterial to the results of operations.

For 2018, we had approximately $0.6 million in other acquisitions.

For 2019, we had approximately $3.7 million in acquisitions.

Mid-Stream

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 $21.8 million, $22.5 million, and $18.6 million, in 2019, 2018, and 2017, respectively. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

Contract Drilling

We did not have any divestitures in 2017.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. The plan included a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer use based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, in December 2018, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax). During 2019, we sold six of these drilling rigs and some of the other equipment to unaffiliated third parties. The proceeds of those sales, less costs to sell, was more than the applicable $5.7 million net book value resulting in a gain of $1.1 million. As of December 31, 2019, we determined that $10.8 million of the assets held for sale would not be sold in the next twelve months and were moved back to long-lived assets. Seven drilling rigs and equipment will be marketed for sale throughout the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.9 million

Mid-Stream

On April 3, 2018, we sold 50% of the ownership interest in our mid-stream segment, Superior. The purchaser is 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. We received $300.0 million from this sale. A portion of the proceeds were used to pay down our bank debt and the remainder were used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company and build additional BOSS drilling rigs. In connection with the sale of the interest in Superior, we took the necessary actions under the Indenture governing our outstanding senior subordinated notes to secure the ability to close the sale and have Superior released from the Indenture.

Superior will be governed and managed under its Amended and Restated Limited Liability Company Agreement and the Master Services and Operating Agreement (MSA) signed by Superior and an affiliate of Unit, as both agreements may be amended occasionally. Further details are in Note 18 – Variable Interest Entity Arrangements.

NOTE 6 – EARNINGS (LOSS) PER SHARE

The following data shows the amounts used in computing earnings (loss) per share:

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2017:			
Basic earnings attributable to Unit Corporation per common share	$ 117,848	51,113	$ 2.31
Effect of dilutive stock options and restricted stock	—	635	(0.03)
Diluted earnings attributable to Unit Corporation per common share	$ 117,848	51,748	$ 2.28
For the year ended December 31, 2018:			
Basic loss attributable to Unit Corporation per common share	$ (45,288)	51,981	$ (0.87)
Effect of dilutive stock options and restricted stock	—	—	—
Diluted loss attributable to Unit Corporation per common share	$ (45,288)	51,981	$ (0.87)
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)

Due to the net loss for the years ended December 31, 2018 and 2019, approximately 934,000 and 428,000, respectively, weighted average shares related to stock options and restricted stock were antidilutive and were excluded from the earnings per share calculation above.

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

	2019	2018	2017
Stock options	42,000	66,500	87,500
Average exercise price	$ 48.56	$ 44.42	$ 51.34

NOTE 7 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31:

	2019	2018
	(In thousands)	
Employee costs	$ 17,832	$ 20,315
Lease operating expenses	9,200	12,756
Interest payable	6,562	6,635
Third-party credits	3,691	2,129
Taxes	3,450	1,378
Other	5,827	4,710
Total accrued liabilities	$ 46,562	$ 47,923

NOTE 8 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

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

	2019	2018
	(In thousands)	
Current portion of long-term debt:		
Unit credit agreement with an average interest rate of 4.0% at December 31, 2019	$ 108,200	$ —
Long-term debt:		
Superior credit agreement with an average interest rate of 3.9% at December 31, 2019	16,500	—
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	$ 666,500	$ 650,000
Less: unamortized discount	(971)	(1,623)
Less: debt issuance costs, net	(2,313)	(3,902)
Total long-term debt	$ 663,216	$ 644,475

Unit Credit Agreement. We have engaged in discussions with the lenders under our Senior Credit Agreement (Unit credit agreement) to enter into an amendment to the Unit credit agreement to, among other things, permit the issuance of new Second Lien Senior Secured Notes (the New Notes), the incurrence of guarantees of the New Notes and the grant of liens securing the New Notes, each of which is currently not permitted under the Unit credit agreement. Due to the Credit Agreement Extension Condition, the company's debt associated with the Unit credit agreement is reflected as a current liability in its consolidated balance sheet as of December 31, 2019. The classification as a current liability is based on the uncertainty regarding the company's ability to repay or refinance the 2021 Senior Notes before November 16, 2020.

Our Unit credit agreement is scheduled to mature on the earlier of (a) October 18, 2023, (b) November 16, 2020, to the extent that, on or before that date, all senior subordinated notes (the Notes) are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023, and (c) any earlier date on which the commitment amounts under the Unit credit agreement are reduced to zero or otherwise terminated. Under that agreement, the amount we can borrow is the lesser of the amount we elect as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $1.0 billion. Effective September 26, 2019, our elected commitment amount and borrowing base are both $275.0 million. We are charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varies 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 are being amortized over the life of the Unit credit agreement. Under the Unit credit agreement, we have 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 such oil and gas properties, Unit Petroleum has also pledged as collateral certain items of its personal property.

On May 2, 2018, we entered into a Pledge Agreement with BOKF, NA (dba Bank of Oklahoma), as administrative agent for the benefit of the secured parties, under which we granted a security interest in the limited liability membership interests and other equity interests we own in Superior (which as of the date of this report is 50% of the aggregate outstanding equity interests of Superior) as additional collateral for our obligations under the Unit credit agreement.

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a one-time special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the Unit credit agreement. Effective September 26, 2019, our borrowing base was reduced from $425.0 million to $275.0 million.

Effective January 17, 2020, our elected commitment amount and borrowing base were reduced to $200.0 million.

At our election, any part of the outstanding debt under the Unit credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.50% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the Unit credit agreement that cannot be less than LIBOR plus 1.00% plus a margin. 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. Interest is 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.

We can use borrowings to finance general working capital requirements for (a) exploration, development, production, and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets up to certain limits, (c) issuance of standby letters of credit, (d) contract drilling services and acquisition of contract drilling equipment, and (e) general corporate purposes.

The Unit credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year over 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions;
- the creation or existence of mortgages or liens, other than those in the ordinary course of business and with certain limited exceptions, on any of our properties, except in favor of our lenders; and
- investments in Unrestricted Subsidiaries (as defined in the Unit credit agreement) over $200.0 million.

The Unit credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1.
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2019, we were in compliance with these covenants.

Superior Credit Agreement. On May 10, 2018, Superior signed a five-year, $200.0 million senior secured revolving credit facility with an option to increase the credit amount up to $250.0 million, subject to certain conditions. 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, among other things, 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, 2019, Superior complied with these covenants.

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

Superior's credit agreement is not guaranteed by Unit.

6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021. In connection with the issuance of the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the 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 and providing for issuing the Notes. The Guarantors are our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

We may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a "change of control" occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder's Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of December 31, 2019.

If an event of default occurs under the Unit credit agreement that accelerates the maturity of at least $25.0 million of borrowings, then it will cause a default under the 2011 Indenture which may in turn accelerate the maturity of the Notes.

On November 5, 2019, we filed with the SEC a registration statement on Form S-4 (the Registration Statement) with respect to an offer to exchange (the Exchange Offer) any and all of our existing Notes for the New Notes, on the terms and conditions in the Registration Statement, and the related consent solicitation. The Registration Statement is not yet effective.

Other Long-Term Liabilities

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

	2019	2018
	(In thousands)	
ARO liability	$ 66,627	$ 64,208
Workers' compensation	11,510	12,738
Finance lease obligations	7,379	11,380
Contract liability	7,061	9,881
Separation benefit plans	10,122	8,814
Deferred compensation plan	6,180	5,132
Gas balancing liability	3,838	3,331
	112,717	115,484
Less current portion	17,376	14,250
Total other long-term liabilities	$ 95,341	$ 101,234

Estimated annual principal payments under the terms of debt and other long-term liabilities from 2020 through 2024 are $125.6 million, $659.3 million, $45.1 million, $19.5 million, and $2.0 million, respectively.

NOTE 9 – 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 of our AROs relate to plugging costs associated with our oil and gas wells.

The following table shows certain information about our AROs for the periods indicated:

	2019	2018
	(In thousands)	
ARO liability, January 1:	$ 64,208	$ 69,444
Accretion of discount	2,343	2,393
Liability incurred	4,373	2,632
Liability settled	(3,261)	(4,493)
Liability sold	(2,953)	(281)
Revision of estimates [1]	1,917	(5,487)
ARO liability, December 31:	66,627	64,208
Less current portion	2,920	1,437
Total long-term ARO liability	$ 63,707	$ 62,771

1. Plugging liability estimates were revised in both 2019 and 2018 for updates in the cost of services used to plug wells over the preceding year. We had various upward and downward adjustments and changes in estimated timing of cash flows.

NOTE 10 – INCOME TAXES

During the fourth quarter of 2017, the U.S. government enacted the Tax Act. Among its many provisions, the Tax Act reduces the federal corporate tax rate from 35% to 21%, effective January 1, 2018. The change in tax law required the company to revalue its existing net deferred tax liability using the lower rate in the period of enactment resulting in the recognition of an income tax benefit of $81.3 million for the year ended December 31, 2017 related to that revaluation. As a result, the company recognized an overall income tax benefit of $57.7 million for the year ended December 31, 2017.

During the third quarter of 2019, we recognized a goodwill impairment charge of $62.8 million. Approximately $50.3 million of this amount was not deductible for income taxes resulting in a reduction of our effective tax rate and reduction of our income tax benefit of approximately $12.3 million for 2019.

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:

	2019	2018	2017
		(In thousands)	
Income tax expense (benefit) computed by applying the statutory rate	$ (144,092)	$ (11,290)	$ 21,059
State income tax expense (benefit), net of federal benefit	(21,733)	(1,882)	1,655
Deferred tax liability revaluation [1]	—	—	(81,307)
Restricted stock shortfall	347	424	1,867
Non-controlling interest in Superior	(11)	(1,138)	—
Goodwill impairment	12,346	—	—
Valuation allowance	19,654	—	—
Statutory depletion and other	1,163	(110)	(952)
Income tax benefit	$ (132,326)	$ (13,996)	$ (57,678)

1. In 2017, the revaluation from the Tax Act.

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

	2019	2018	2017
		(In thousands)	
Current taxes:			
Federal	$ (918)	$ (1,835)	$ —
State	(363)	(1,296)	5
	(1,281)	(3,131)	5
Deferred taxes:			
Federal	(108,440)	(8,741)	(62,788)
State	(22,605)	(2,124)	5,105
	(131,045)	(10,865)	(57,683)
Total provision	$ (132,326)	$ (13,996)	$ (57,678)

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

	2019	2018
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 31,822	$ 27,953
Net operating loss carryforward	246,927	152,112
Alternative minimum tax and research and development tax credit carryforward	2,656	3,574
	281,405	183,639
Deferred tax liability:		
Depreciation, depletion, amortization, and impairment	(226,034)	(291,542)
Investment in Superior	(49,430)	(36,845)
Net deferred tax asset (liability)	5,941	(144,748)
Valuation allowance	(19,654)	—
Current deferred tax asset	—	—
Non-current—deferred tax liability	$ (13,713)	$ (144,748)

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 statement 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.

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, 2019, we have expected federal net operating loss carryforwards of approximately $980.8 million of which $584.2 million will expire from 2021 to 2037.

NOTE 11 – 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. We made discretionary contributions under the plan of 310,797, 184,203, and 155,822 shares of common stock and recognized expense of $5.2 million, $5.1 million, and $4.4 million in 2019, 2018, and 2017, respectively. In 2020, the contribution under the plan for 2019 was made in cash instead of shares of common stock.

We provide a salary deferral plan for our executives (Deferral Plan) which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. The liability recorded under the Deferral Plan at December 31, 2019 and 2018 was $6.2 million and $5.1 million, respectively. We recognized payroll expense and recorded a liability at the time of deferral.

Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed up to a maximum of 104 weeks. To receive payments, the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan (Special Plan). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company.

On December 31, 2008, we amended all three Plans to be in compliance with Section 409A of the Internal Revenue Code of 1986, as amended. The key amendments to the Plans address, among other things, when distributions may be made, the timing of payments, and the circumstances under which employees become eligible to receive benefits. On December 8, 2015, we amended the Plans to change the calculation for determining the payouts at the time of a Separation of Service under the Plans. None of the amendments materially increase the benefits, grants or awards issuable under the Plans. We recognized expense of $3.8 million, $3.6 million, and $2.7 million in 2019, 2018, and 2017, respectively, for benefits associated with anticipated payments from these separation plans.

We have entered into key employee change of control contracts with three of our current executive officers. These severance contracts have an initial three-year term that is automatically extended for one year on each anniversary, unless a notice not to extend is given by us. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive's terms and conditions for employment (including position, work location, compensation, and benefits) will not be adversely changed during the three-year period after a change of control. If the executive's employment is terminated (other than for cause, death, or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and on certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 12 – 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. Previously, there were three non-employee partnerships, one that was formed in 1984 and two formed in 1986 (investments by third parties). Effective December 31, 2014, the 1984 partnership was dissolved and effective December 31, 2016, the two 1986 partnerships were also dissolved. 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.

Amounts received in the years ended December 31, from both public and private Partnerships for which Unit was a general partner are as follows:

	2019	2018	2017
		(In thousands)	
Well supervision and other fees	$ 1	$ 158	$ 172
General and administrative expense reimbursement	—	—	—

Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party's behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable.

One of our directors, 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, in some cases, as lessee, with respect to certain wells in which Mr. Peyton, members of Mr. Peyton's family, and Peyton Royalties, LP have an interest. Such payments totaled approximately $0.4 million, $0.9 million, and $0.7 million during 2019, 2018, and 2017, respectively.

Our Audit Committee and the board, in accordance with our related party transaction policy, have determined that these arrangements are in the best interest of the company.

NOTE 13 – STOCK-BASED COMPENSATION

For restricted stock awards, we had:

	2019	2018	2017
		(In millions)	
Recognized stock compensation expense	$ 12.8	$ 17.8	$ 13.3
Capitalized stock compensation cost for our oil and natural gas properties	2.4	2.1	1.8
Tax benefit on stock based compensation	3.1	4.4	5.0

The remaining unrecognized compensation cost related to unvested awards at December 31, 2019 is approximately $13.1 million of which $1.9 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.7 of a year.

The Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the amended plan) allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) and to non-employee directors. A total of 7,230,000 shares of the company's common stock is authorized for issuance to eligible participants under the amended plan with 2.0 million shares being the maximum number of shares that can be issued as "incentive stock options." Awards under this plan may be granted in any one or a combination of the following:

- incentive stock options under Section 422 of the Internal Revenue Code;
- non-qualified stock options;
- performance shares;
- performance units;
- restricted stock;
- restricted stock units;
- stock appreciation rights;

- cash based awards; and
- other stock-based awards.

This plan also contains various limits as to the amount of awards that can be given to an employee in any fiscal year. All awards are generally subject to the minimum vesting periods, as determined by our Compensation Committee and included in the award agreement.

Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercise and termination rates within the model and aggregate groups that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised.

SARs

In 2017, all of the remaining SARs were forfeited. There were no SARs granted or vested during 2019, 2018, or 2017. The SARs expired after 10 years from the date of the grant, and there were no outstanding shares at December 31, 2019.

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, 2017	929,737	372,128	1,301,865	$ 23.32
Granted	485,799	173,373	659,172	26.07
Vested	(455,570)	(62,119)	(517,689)	29.87
Forfeited	(44,408)	(34,953)	(79,361)	38.87
Nonvested at December 31, 2017	915,558	448,429	1,363,987	21.25
Granted	844,498	390,445	1,234,943	20.52
Vested	(470,171)	(209,643)	(679,814)	24.30
Forfeited	(21,002)	(21,106)	(42,108)	19.80
Nonvested at December 31, 2018	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	1,527,648	841,374	2,369,022	$ 18.95

Non-Employee Directors	Number of Shares	Weighted Average Price
Nonvested at January 1, 2017	111,816	$ 17.21
Granted	49,104	17.92
Vested	(43,206)	21.24
Forfeited	—	—
Nonvested at December 31, 2017	117,714	$ 16.03
Granted	44,312	19.86
Vested	(54,981)	17.08
Forfeited	—	—
Nonvested at December 31, 2018	107,045	$ 17.07
Granted	72,784	12.09
Vested	(61,141)	15.49
Forfeited	—	—
Nonvested at December 31, 2019	118,688	$ 14.83

The time vested restricted stock awards granted are being recognized over a three year vesting period. Each year, there were two different performance vested restricted stock awards granted to certain executive officers. The first will cliff vest three years from the grant date based on the company's achievement of certain stock performance measures at the end of the term and will range from 0% to 200% of the restricted shares granted as performance shares. The second will vest, one-third each year, over a three year vesting period based on the company's achievement of cash flow to total assets (CFTA) performance measurement each year and will range from 0% to 200%. Based on a probability assessment of the selected performance criteria at December 31, 2019, the participants are estimated to receive 3% of the 2019, 45% of the 2018, and 0% of the 2017 performance based shares. The CFTA performance measurement at December 31, 2019 for the one-third vesting in 2019 was assessed to vest at 100%. The CFTA performance measurement for future years was assessed to vest at target or 100%.

The fair value of the restricted stock granted in 2019, 2018, and 2017 at the grant date was $22.6 million, $24.7 million, and $17.4 million, respectively. The aggregate intrinsic value of the 865,083 shares of restricted stock that vested in 2019 on their vesting date was $11.9 million. The aggregate intrinsic value of the 2,487,710 shares of restricted stock outstanding subject to vesting at December 31, 2019 was $1.7 million with a weighted average remaining life of 1.0 of a year.

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. The option price for each stock option was the fair market value of the common stock on the date the stock options were granted. The term of each option is 10 years and cannot be increased and no stock options were to be exercised during the first six months of its term except in case of death.

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2017	108,500	$ 52.56
Granted	—	—
Exercised	—	—
Forfeited	(21,000)	57.63
Outstanding at December 31, 2017	87,500	51.34
Granted	—	—
Exercised	—	—
Forfeited	(21,000)	73.26
Outstanding at December 31, 2018	66,500	44.42
Granted	—	—
Exercised	—	—
Forfeited	(24,500)	37.31
Outstanding at December 31, 2019	42,000	$ 48.56

	Outstanding and Exercisable Options at December 31, 2019		
Weighted Average Exercise Price	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$41.21	17,500	0.3 years	$ 41.21
$53.81	24,500	1.3 years	$ 53.81

There was no aggregate intrinsic value of the shares outstanding subject to options at December 31, 2019. The remaining weighted average remaining contractual term is 0.9 years.

NOTE 14 – 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 of December 31, 2019, our derivative transactions consisted of the following types of hedges:

- *Basis 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 swaps to hedge the price risk between NYMEX and its physical delivery points.
- *Three-way collars.* A three-way collar contains a fixed floor price (long put), fixed subfloor price (short put) and a fixed ceiling price (short call). If the market price exceeds the ceiling strike price, we receive the ceiling strike price and pay the market price. If the market price is between the ceiling and the floor strike price, no payments are due from either party. If the market price is below the floor price but above the subfloor price, we receive the floor strike price and pay the market price. If the market price is below the subfloor price, we receive the market price plus the difference between the floor and subfloor strike prices and pay the market price.

We have documented policies and procedures to monitor and control the use of derivative instruments. 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, 2019, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'20 - Dec'20	Natural gas - basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jan'20 - Dec'20	Natural gas - basis swap	20,000 MMBtu/day	$(0.455)	PEPL
Jan'21 - Dec'21	Natural gas - basis swap	30,000 MMBtu/day	$(0.215)	NGPL TEXOK
Jan'20 - Dec'20	Natural gas - three-way collar	30,000 MMBtu/day	$2.50 - $2.20 - $2.80	IF - NYMEX (HH)

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

	Balance Sheet Location	Derivative Assets Fair Value 2019	2018
		(In thousands)	
Commodity derivatives:			
Current	Current derivative assets	$ 633	$ 12,870
Long-term	Non-current derivative assets	—	—
Total derivative assets		$ 633	$ 12,870

	Balance Sheet Location	Derivative Liabilities Fair Value 2019	2018
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liabilities	$ —	$ —
Long-term	Non-current derivative liabilities	27	293
Total derivative liabilities		$ 27	$ 293

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.

Effect of derivative instruments on the Consolidated Statements of Operations for the year ended December 31:

Derivatives Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative 2019	2018
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives [1]	$ 4,225	$ (3,184)
Total		$ 4,225	$ (3,184)

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1. Amounts settled during the periods are a gain of $16,196 and a loss of $22,803, respectively.

NOTE 15 – 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 of our financial instruments.

The following tables set forth our recurring fair value measurements:

	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

	December 31, 2018			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$ 3,225	$ 10,964	$ (1,319)	$ 12,870
Liabilities	(1,278)	(334)	1,319	(293)
	$ 1,947	$ 10,630	$ —	$ 12,577

All of 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, 2019.

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 level 3 fair value measurements:

	Net Derivatives	
	For the Year Ended,	
	December 31, 2019	December 31, 2018
	(In thousands)	
Beginning of period	$ 10,630	$ (206)
Total gains or losses:		
Included in earnings	(1,494)	4,159
Settlements	(7,932)	6,677
End of period	$ 1,204	$ 10,630
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	$ (9,426)	$ 10,836

The following table provides quantitative information about our Level 3 unobservable inputs at December 31, 2019:

Commodity (1)	Fair Value	Valuation Technique	Unobservable Input	Range
	(In thousands)			
Natural gas three-way collar	$ 1,204	Discounted cash flow	Forward commodity price curve	$0.00 - $0.39

1. The commodity contracts detailed in this category include non-exchange-traded natural gas three-way collars that are valued based on NYMEX. The forward pricing range represents the low and high price expected to be received within the settlement period.

Based on our valuation at December 31, 2019, we determined that the non-performance risk with regard to our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values 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, 2019, the carrying values on the consolidated balance sheets for 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.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and also considering the risk of our non-performance, long-term debt under our credit agreements at December 31, 2019 would approximate its fair value. This debt would be classified as Level 2.

The carrying amounts 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 and December 31, 2018 were $646.7 million and $644.5 million, respectively. We estimate the fair value of these Notes using quoted marked prices at December 31, 2019 and December 31, 2018 were $357.5 million and $600.5 million, respectively. These Notes would be 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 9 – 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 2018 and 2019, we recorded non-cash impairment charges discussed further in Note 3 – Summary

Of Significant Accounting Policies. The valuation of these assets requires the use of significant unobservable inputs classified as Level 3.

NOTE 16 – LEASES

Operating Leases under ASC 840

We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; and Pinedale, Wyoming under the terms of operating leases expiring through December 2021. We own our corporate headquarters in Tulsa, Oklahoma. We also have several compressor rentals, equipment leases, and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. As of December 31, 2018, future minimum rental payments under the terms of the leases under ASC 840 were approximately \$4.6 million, \$1.7 million, and \$0.4 million in 2019 through 2021, respectively.

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 not adjusted and continue to be reported under the accounting standards in effect for those periods.

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 implicit in the lease to discount lease payments to present value; however, most of our leases do not provide a readily determinable implicit 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 another asset in accordance with other U.S. GAAP. 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. As of December 31, 2019, we had an average working interest of 95% in our operated properties.

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. Routinely, our oil and natural gas segment contracts 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.

Leases. 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 shows supplemental cash flow information related to leases for the year ended December 31, 2019:

	Amount
	(In thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for operating leases	$ 4,034
Financing cash flows for finance leases	4,001
Lease liabilities recognized in exchange for new operating lease right of use assets	5

The following table shows information about our lease assets and liabilities included in our Consolidated Balance Sheet as of December 31, 2019:

	Classification on the Consolidated Balance Sheet	December 31, 2019
		(In thousands)
Assets		
Operating right of use assets	Right of use assets	$ 5,673
Finance right of use assets	Property, plant, and equipment, net	17,396
Total right of use assets		$ 23,069
Liabilities		
Current liabilities:		
Operating lease liabilities	Current operating lease liabilities	$ 3,430
Finance lease liabilities	Current portion of other long-term liabilities	4,164
Non-current liabilities:		
Operating lease liabilities	Operating lease liabilities	2,071
Finance lease liabilities	Other long-term liabilities	3,215
Total lease liabilities		$ 12,880

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

	2019
Components of total lease cost:	
Amortization of finance leased assets	$ 4,001
Interest on finance lease liabilities	382
Operating lease cost	4,034
Short-term lease cost [(1)]	38,868
Variable lease cost	351
Total lease cost	$ 47,636

1. Short-term lease cost includes amounts capitalized related to our oil and natural gas segment of $25.1 million.

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:

	Weighted Average Remaining Lease Term	Weighted Average Discount Rate [(1)]
	(In years)	
Operating leases	1.9	6.13%
Finance leases	1.7	4.00%

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

The following table sets forth the maturity of our operating lease liabilities as of December 31, 2019:

	Amount
	(In thousands)
Ending January 1,	
2021	$ 3,670
2022	1,614
2023	419
2024	73
2025	12
2026 and beyond	75
Total future payments	5,863
Less: Interest	362
Present value of future minimum operating lease payments	5,501
Less: Current portion	3,430
Total long-term operating lease payments	$ 2,071

Finance Leases

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 $4.2 million is included in current portion of other long-term liabilities and the non-current portion of $3.2 million is included in other long-term liabilities in the accompanying Consolidated Balance Sheets as of December 31, 2019. These finance leases are discounted using annual rates of 4.0%. Total maintenance and interest remaining related to these leases are $2.3 million and $0.3 million, respectively at December 31, 2019. Annual payments, net of maintenance and interest, average $4.4 million annually through 2021. 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, 2019 are as follows:

	Amount
Ending January 1,	(In thousands)
2021	$ 6,194
2022	3,774
Total future payments	9,968
Less payments related to:	
Maintenance	2,336
Interest	253
Present value of future minimum payments	7,379
Less: Current portion	4,164
Total long-term finance lease payments	$ 3,215

NOTE 17 – COMMITMENTS AND CONTINGENCIES

The employee oil and gas limited partnerships required, on the election of a limited partner, that we repurchase the limited partner’s interest at amounts to be determined by appraisal in the future. These repurchases in any one year were limited to 20% of the units outstanding. 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.

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 environmental liability 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.

During the second quarter of 2018, as part of the Superior transaction, we entered into a contractual obligation that commits us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. This amount is included in our future drilling plans. For each dollar of the $150.0 million that we do not spend (over the three-year period), we would forgo receiving $0.58 of future distributions from our 50% ownership interest in our consolidated mid-stream subsidiary. At December 31, 2019, 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 $72.7 million. Total spent towards the $150.0 million as of December 31, 2019 was $24.7 million.

For 2019, we have committed to purchase approximately $0.9 million of new pipe and equipment. We have firm transportation commitments to transport our natural gas from various systems for approximately $2.8 million over the next twelve months and $0.7 million for the two years thereafter.

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matter, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position, or cash flows.

NOTE 18 – 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 will be governed and managed under the Amended and Restated

Limited Liability Company Agreement and the MSA. The MSA is between our affiliate, SPC Midstream Operating, L.L.C. (the Operator) and Superior. The Operator is owned 100% by Unit Corporation. 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 houses the power to direct the activities that most significantly impact Superior's operating performance. The MSA is a separate variable interest. Unit through the MSA has the power to direct Superior's most significant activities; reciprocally the equity investors lack the power to direct the activities that most significantly impact 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, 2019.

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, and 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.

On the sale or liquidation of Superior, distributions would occur in the order and priority specified in the relevant agreements.

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 $255,970. Superior's creditors have no recourse to our general credit. Superior's credit agreement is not guaranteed by Unit. 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 carrying value of Superior's assets and liabilities, after eliminations of any intercompany transactions and balances, in the consolidated balance sheets were as follows:

	December 31, 2019	December 31, 2018
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ —	$ 5,841
Accounts receivable	21,073	33,207
Prepaid expenses and other	7,686	1,049
Total current assets	28,759	40,097
Property and equipment:		
Gas gathering and processing equipment	824,699	767,388
Transportation equipment	3,390	3,086
	828,089	770,474
Less accumulated depreciation, depletion, amortization, and impairment	407,144	364,740
Net property and equipment	420,945	405,734
Right of use assets	3,948	—
Other assets	9,442	17,551
Total assets	$ 463,094	$ 463,382
Current liabilities:		
Accounts payable	$ 18,511	$ 32,214
Accrued liabilities	4,198	3,688
Current operating lease liability	2,407	—
Current portion of other long-term liabilities	7,060	6,875
Total current liabilities	32,176	42,777
Long-term debt less debt issuance costs	16,500	—
Operating lease liability	1,404	—
Other long-term liabilities	8,126	14,687
Total liabilities	$ 58,206	$ 57,464

NOTE 19 – EQUITY

At-the-Market (ATM) Common Stock Program

On April 4, 2017, we entered into a Distribution Agreement (the Agreement) with a sales agent, under which we may offer and sell, from time to time, through the sales agent shares of our common stock, par value $0.20 per share (the Shares), up to an aggregate offering price of $100.0 million. We intended to use the net proceeds from these sales to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

On May 2, 2018, we terminated the Distribution Agreement. The Distribution Agreement was terminable at will on written notification by us with no penalty. As of the date of termination, we had sold 787,547 shares of our common stock under the Distribution Agreement resulting in net proceeds of approximately $18.6 million. We paid the sales agent a commission of 2.0% of the gross sales price per share sold. As a result of the termination, there will be no more sales of our common stock under the Distribution Agreement.

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. Our oil and natural gas production outside the United States is not significant.

The following table provides certain information about the operations of each of our segments:

	Year Ended December 31, 2019					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: (1)						
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	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-down 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.

	Year Ended December 31, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 423,059	$ —	$ —	$ —	$ —	$ 423,059
Contract drilling	—	218,982	—	—	(22,490)	196,492
Gas gathering and processing	—	—	312,417	—	(88,687)	223,730
Total revenues [1]	423,059	218,982	312,417	—	(111,177)	843,281
Expenses:						
Operating costs:						
Oil and natural gas	136,870	—	—	—	(5,195)	131,675
Contract drilling	—	150,834	—	—	(19,449)	131,385
Gas gathering and processing	—	—	251,328	—	(83,492)	167,836
Total operating costs	136,870	150,834	251,328	—	(108,136)	430,896
Depreciation, depletion and amortization	133,584	57,508	44,834	7,679	—	243,605
Impairments [2]	—	147,884	—	—	—	147,884
Total expenses	270,454	356,226	296,162	7,679	(108,136)	822,385
General and administrative	—	—	—	38,707	—	38,707
Gain on disposition of assets	(139)	(425)	(110)	(30)	—	(704)
Income (loss) from operations	152,744	(136,819)	16,365	(46,356)	(3,041)	(17,107)
Loss on derivatives	—	—	—	(3,184)	—	(3,184)
Interest expense, net	—	—	(1,214)	(32,280)	—	(33,494)
Other	—	—	—	22	—	22
Income (loss) before income taxes	$ 152,744	$ (136,819)	$ 15,151	$ (81,798)	$ (3,041)	$ (53,763)
Identifiable assets:						
Oil and natural gas [3]	$ 1,357,779	$ —	$ —	$ —	$ (6,949)	$ 1,350,830
Contract drilling	—	806,696	—	—	(85)	806,611
Gas gathering and processing	—	—	466,851	—	(5,023)	461,828
Total identifiable assets [4]	1,357,779	806,696	466,851	—	(12,057)	2,619,269
Corporate land and building	—	—	—	55,505	—	55,505
Other corporate assets [5]	—	—	—	25,566	(2,287)	23,279
Total assets	$ 1,357,779	$ 806,696	$ 466,851	$ 81,071	$ (14,344)	$ 2,698,053
Capital expenditures:	$ 367,335	$ 75,510	$ 44,810	$ 1,125	$ —	$ 488,780

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. Impairment for contract drilling equipment includes a $147.9 million pre-tax write-down for 41 drilling rigs and other drilling equipment.
3. Oil and natural gas assets include oil and natural gas properties, saltwater disposal systems, and other non-full cost pool assets.
4. Identifiable assets are those used in Unit's operations in each industry segment.
5. Other corporate assets are principally cash and cash equivalents, short-term investments, transportation equipment, furniture, and equipment.

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

	Year Ended December 31, 2017					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$ 357,744	$ —	$ —	$ —	$ —	$ 357,744
Contract drilling	—	188,172	—	—	(13,452)	174,720
Gas gathering and processing	—	—	277,049	—	(69,873)	207,176
Total revenues	357,744	188,172	277,049	—	(83,325)	739,640
Expenses:						
Operating costs:						
Oil and natural gas	135,532	—	—	—	(4,743)	130,789
Contract drilling	—	134,432	—	—	(11,832)	122,600
Gas gathering and processing	—	—	220,613	—	(65,130)	155,483
Total operating costs	135,532	134,432	220,613	—	(81,705)	408,872
Depreciation, depletion and amortization	101,911	56,370	43,499	7,477	—	209,257
Total expenses	237,443	190,802	264,112	7,477	(81,705)	618,129
General and administrative	—	—	—	38,087	—	38,087
(Gain) loss on disposition of assets	(228)	776	(25)	(850)	—	(327)
Income (loss) from operations	120,529	(3,406)	12,962	(44,714)	(1,620)	83,751
Gain on derivatives	—	—	—	14,732	—	14,732
Interest expense, net	—	—	—	(38,334)	—	(38,334)
Other	—	—	—	21	—	21
Income (loss) before income taxes	$ 120,529	$ (3,406)	$ 12,962	$ (68,295)	$ (1,620)	$ 60,170
Identifiable assets:						
Oil and natural gas [(1)]	$ 1,134,080	$ —	$ —	$ —	$ (6,180)	$ 1,127,900
Contract drilling	—	933,063	—	—	—	933,063
Gas gathering and processing	—	—	439,369	—	(798)	438,571
Total identifiable assets [(2)]	1,134,080	933,063	439,369	—	(6,978)	2,499,534
Corporate land and building	—	—	—	56,854	—	56,854
Other corporate assets [(3)]	—	—	—	25,064	—	25,064
Total assets	$ 1,134,080	$ 933,063	$ 439,369	$ 81,918	$ (6,978)	$ 2,581,452
Capital expenditures:	$ 270,443	$ 36,148	$ 22,168	$ 3,521	$ —	$ 332,280

1. Oil and natural gas assets include oil and natural gas properties, saltwater disposal systems, and other non-full cost pool assets.
2. Identifiable assets are those used in Unit's operations in each industry segment.
3. 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:

	Three Months Ended				
	March 31	June 30	September 30	December 31	
	(In thousands except per share amounts)				
2018					
Revenues	$ 205,132	$ 203,303	$ 220,058	$ 214,788	
Gross income (loss) [1]	$ 38,833	$ 40,915	$ 49,216	$ (108,068)	
Net income (loss) attributable to Unit Corporation	$ 7,865	$ 5,788	$ 18,899	$ (77,840)	(2)
Net income (loss) attributable to Unit Corporation per common share:					
Basic	$ 0.15	$ 0.11	$ 0.36	$ (1.49)	
Diluted	$ 0.15	$ 0.11	$ 0.36	$ (1.49)	
2019					
Revenues [3]	$ 189,691	$ 165,146	$ 155,439	$ 164,358	
Gross income (loss) [1]	$ 24,095	$ 813	$ (242,308)	$ (393,983)	
Net loss attributable to Unit Corporation	$ (3,504)	$ (8,509)	$ (206,886) (4)	$ (334,980)	(5)
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)	

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1. Gross income (loss) excludes general and administrative expense, interest expense, (gain) loss on disposition of assets, gain (loss) on derivatives, income taxes, and other income (loss).
2. In the fourth quarter of 2018, we recorded an impairment for contract drilling equipment that included a $147.9 million pre-tax write-down for 41 drilling rigs and other drilling equipment.
3. In 2019, revenues dropped significantly each quarter due to lower commodity prices, production, and drilling rig utilization.
4. 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).
5. 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

We have no significant assets or operations other than our investments in our subsidiaries. Our wholly owned subsidiaries are the guarantors of our Notes. On April 3, 2018, we sold 50% of the ownership interest in our mid-stream segment, Superior and that company and its subsidiaries are no longer guarantors of the Notes. Instead of providing separate financial statements for each subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X.

For purposes of the following footnote:

- we are referred to as "Parent",
- the direct subsidiaries are 100% owned by the Parent and the guarantee is full and unconditional and joint and several and referred to as "Combined Guarantor Subsidiaries", and
- Superior and its subsidiaries and the Operator are referred to as "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 Balance Sheets

	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
Current 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)

	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 liabilities	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

	December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 403	$ 208	$ 5,841	$ —	$ 6,452
Accounts receivable, net of allowance for doubtful accounts of $2,531 (Guarantor of $1,326 and Parent of $1,205)	2,328	94,737	36,676	(14,344)	119,397
Materials and supplies	—	473	—	—	473
Current derivative asset	12,870	—	—	—	12,870
Current income tax receivable	243	1,811	—	—	2,054
Assets held for sale	—	22,511	—	—	22,511
Prepaid expenses and other	1,993	3,560	1,049	—	6,602
Total current assets	17,837	123,300	43,566	(14,344)	170,359
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	6,018,568	—	—	6,018,568
Unproved properties not being amortized	—	330,216	—	—	330,216
Drilling equipment	—	1,284,419	—	—	1,284,419
Gas gathering and processing equipment	—	—	767,388	—	767,388
Saltwater disposal systems	—	68,339	—	—	68,339
Corporate land and building	—	59,081	—	—	59,081
Transportation equipment	9,273	17,165	3,086	—	29,524
Other	28,584	28,923	—	—	57,507
	37,857	7,806,711	770,474	—	8,615,042
Less accumulated depreciation, depletion, amortization, and impairment	27,504	5,790,481	364,741	—	6,182,726
Net property and equipment	10,353	2,016,230	405,733	—	2,432,316
Intercompany receivable	950,871	—	—	(950,871)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,362,526	—	—	(1,362,526)	—
Other assets	8,225	6,793	17,552	—	32,570
Total assets	$ 2,349,812	$ 2,209,131	$ 466,851	$ (2,327,741)	$ 2,698,053

	December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 9,466	$ 122,608	$ 32,215	$ (12,603)	$ 151,686
Accrued liabilities	27,505	16,539	5,620	(1,741)	47,923
Current portion of other long-term liabilities	812	6,563	6,875	—	14,250
Total current liabilities	37,783	145,710	44,710	(14,344)	213,859
Intercompany debt	—	948,790	2,081	(950,871)	—
Long-term debt less debt issuance costs	644,475	—	—	—	644,475
Non-current derivative liabilities	293	—	—	—	293
Other long-term liabilities	12,834	73,713	14,687	—	101,234
Deferred income taxes	60,983	83,765	—	—	144,748
Total shareholders' equity	1,593,444	957,153	405,373	(1,362,526)	1,593,444
Total liabilities and shareholders' equity	$ 2,349,812	$ 2,209,131	$ 466,851	$ (2,327,741)	$ 2,698,053

Condensed Consolidating Statements of Operations

	Year 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 expenses	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	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)

	Year Ended December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Revenues	$ —	$ 619,551	$ 312,417	$ (88,687)	$ 843,281
Expenses:					
Operating costs	—	268,255	251,328	(88,687)	430,896
Depreciation, depletion, and amortization	7,679	191,092	44,834	—	243,605
Impairments	—	147,884	—	—	147,884
General and administrative	—	36,083	2,624	—	38,707
Gain on disposition of assets	(30)	(564)	(110)	—	(704)
Total operating expenses	7,649	642,750	298,676	(88,687)	860,388
Income (loss) from operations	(7,649)	(23,199)	13,741	—	(17,107)
Interest, net	(32,280)	—	(1,214)	—	(33,494)
Loss on derivatives	(3,184)	—	—	—	(3,184)
Other	22	—	—	—	22
Income (loss) before income taxes	(43,091)	(23,199)	12,527	—	(53,763)
Income tax expense (benefit)	(11,962)	(4,064)	2,030	—	(13,996)
Equity in net earnings from investment in subsidiaries, net of taxes	(8,638)	—	—	(8,638)	—
Net income (loss)	(39,767)	(19,135)	10,497	(8,638)	(39,767)
Less: net income attributable to non-controlling interest	5,521	—	5,521	(5,521)	5,521
Net income (loss) attributable to Unit Corporation	$ (45,288)	$ (19,135)	$ 4,976	$ (3,117)	$ (45,288)

	Year Ended December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 534,084	$ 277,049	$ (71,493)	$ 739,640
Expenses:					
Operating costs	—	258,132	220,613	(69,873)	408,872
Depreciation, depletion, and amortization	7,477	158,281	43,499	—	209,257
General and administrative	—	29,440	8,647	—	38,087
(Gain) loss on disposition of assets	(850)	548	(25)	—	(327)
Total operating expenses	6,627	446,401	272,734	(69,873)	655,889
Income (loss) from operations	(6,627)	87,683	4,315	(1,620)	83,751
Interest, net	(37,645)	—	(689)	—	(38,334)
Gain on derivatives	14,732	—	—	—	14,732
Other	21	—	—	—	21
Income (loss) before income taxes	(29,519)	87,683	3,626	(1,620)	60,170
Income tax benefit	(12,599)	(20,881)	(24,198)	—	(57,678)
Equity in net earnings from investment in subsidiaries, net of taxes	134,768	—	—	(134,768)	—
Net income	117,848	108,564	27,824	(136,388)	117,848
Less: net income attributable to non-controlling interest	—	—	—	—	—
Net income attributable to Unit Corporation	$ 117,848	$ 108,564	$ 27,824	$ (136,388)	$ 117,848

Condensed Consolidating Statements of Comprehensive Income (Loss)

	Year 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 of ($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)

	Year Ended December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income (loss)	$ (39,767)	$ (19,135)	$ 10,497	$ (8,638)	$ (39,767)
Other comprehensive income, net of taxes:					
Unrealized loss on securities, net of tax of ($181)	—	(557)	—	—	(557)
Comprehensive income	(39,767)	(19,692)	10,497	(8,638)	(40,324)
Less: Comprehensive income attributable to non-controlling interests	5,521	—	5,521	(5,521)	5,521
Comprehensive income (loss) attributable to Unit Corporation	$ (45,288)	$ (19,692)	$ 4,976	$ (3,117)	$ (45,845)

	Year Ended December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
Net income	$ 117,848	$ 108,564	$ 27,824	$ (136,388)	$ 117,848
Other comprehensive income, net of taxes:					
Unrealized income on securities, net of tax of $39	—	63	—	—	63
Comprehensive income	117,848	108,627	27,824	(136,388)	117,911
Less: Comprehensive income attributable to non-controlling interests	—	—	—	—	—
Comprehensive income attributable to Unit Corporation	$ 117,848	$ 108,627	$ 27,824	$ (136,388)	$ 117,911

Condensed Consolidating Statements of Cash Flows

	Year 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 property and other oil and natural gas acquisitions	—	(3,653)	—	—	(3,653)
Other acquisitions	—	—	(16,109)	—	(16,109)
Proceeds from disposition of property and equipment	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 agreements	400,600	—	92,900	—	493,500
Payments under credit agreements	(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 financing activities	9,705	109,735	12,184	(12,338)	119,286
Net increase 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

	Year Ended December 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (310,120)	$ 324,696	$ 12,257	$ 325,914	$ 352,747
INVESTING ACTIVITIES:					
Capital expenditures	236	(400,990)	(45,528)	—	(446,282)
Producing properties and other acquisitions	—	(29,970)	—	—	(29,970)
Proceeds from disposition of property and equipment	30	25,777	103	—	25,910
Net cash used in investing activities	266	(405,183)	(45,425)	—	(450,342)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	97,100	—	2,000	—	99,100
Payments under credit agreement	(275,100)	—	(2,000)	—	(277,100)
Intercompany borrowings (advances), net	202,558	80,504	(154,982)	(128,080)	—
Payments on finance leases	—	—	(3,843)	—	(3,843)
Proceeds from investments in non-controlling interest	300,000	—	197,042	(197,042)	300,000
Employee taxes paid by withholding shares	(4,988)	—	—	—	(4,988)
Transaction costs associated with sale of non-controlling interest	(2,503)	—	—	—	(2,503)
Bank overdrafts	(7,320)	—	—	—	(7,320)
Net cash provided by (used in) financing activities	309,747	80,504	39,009	(325,914)	103,346
Net increase in cash and cash equivalents	(107)	17	5,841	—	5,751
Cash and cash equivalents, beginning of period	510	191	—	—	701
Cash and cash equivalents, end of period	$ 403	$ 208	$ 5,841	$ —	$ 6,452

	Year Ended December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
			(In thousands)		
OPERATING ACTIVITIES:					
Net cash provided by operating activities	$ 3,458	$ 223,437	$ 43,193	$ —	$ 270,088
INVESTING ACTIVITIES:					
Capital expenditures	(3,594)	(233,254)	(18,705)	—	(255,553)
Producing properties and other acquisitions	—	(58,026)	—	—	(58,026)
Proceeds from disposition of property and equipment	964	20,674	75	—	21,713
Other	—	(1,500)	—	—	(1,500)
Net cash provided by (used in) investing activities	(2,630)	(272,106)	(18,630)	—	(293,366)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	343,900	—	—	—	343,900
Payments under credit agreement	(326,700)	—	—	—	(326,700)
Intercompany borrowings (advances), net	(27,615)	48,484	(20,869)	—	—
Payments on finance leases	—	—	(3,694)	—	(3,694)
Proceeds from common stock issued, net of issue costs	18,623	—	—	—	18,623
Employee taxes paid by withholding shares	(4,132)	—	—	—	(4,132)
Bank overdrafts	(4,911)	—	—	—	(4,911)
Net cash used in financing activities	(835)	48,484	(24,563)	—	23,086
Net increase in cash and cash equivalents	(7)	(185)	—	—	(192)
Cash and cash equivalents, beginning of period	517	376	—	—	893
Cash and cash equivalents, end of period	$ 510	$ 191	$ —	$ —	$ 701

NOTE 23 – SUBSEQUENT EVENTS

On March 11, 2020, we entered into a Standstill and Amendment Agreement (Standstill Agreement) with the lenders and administrative agent party to the Unit credit agreement. The Standstill Agreement, among other things, provides that during the standstill period (as defined below), the administrative agent and lenders under the Unit credit agreement agree to temporarily standstill from making any final determination in connection with the pending scheduled redetermination of the borrowing base that was, under the Unit credit agreement, otherwise scheduled to be made on or about April 1, 2020, and from otherwise exercising certain of their respective rights and remedies under the Unit credit agreement. The standstill period will begin after the effective date of the Standstill Agreement and will continue until the earlier of: (i) the receipt by any credit party from the administrative agent of notice of the occurrence of any termination event and (ii) 3:00 p.m. central time on April 15, 2020. "Termination event" is defined under the Standstill Agreement to include the occurrence of any one or more of the following: (i) any representation or warranty made or deemed to have been made by any credit party under the Standstill Agreement being false, misleading or erroneous in any material respect when made or deemed to have been made, (ii) any credit party failing to perform, observe or comply with any covenant, agreement or term contained in the Standstill Agreement in any material respect or (iii) any default which is not cured within five (5) business days or event of default occurring under the Unit credit agreement. Under the Standstill Agreement, we are prevented from withdrawing more than an additional $15.0 million, in the aggregate, net of repayments, and we have agreed to make repayments using any excess cash, among certain other conditions.

SUPPLEMENTAL OIL AND GAS DISCLOSURES

(UNAUDITED)

Our oil and gas operations are substantially located in the United States. The capitalized costs at year end and costs incurred during the year were as follows:

	2019	2018	2017
	(In thousands)		
Capitalized costs:			
Proved properties	$ 6,341,582	$ 6,018,568	$ 5,712,813
Unproved properties	252,874	330,216	296,764
	6,594,456	6,348,784	6,009,577
Accumulated depreciation, depletion, amortization, and impairment	(5,846,177)	(5,124,257)	(4,996,696)
Net capitalized costs	$ 748,279	$ 1,224,527	$ 1,012,881
Cost incurred:			
Unproved properties acquired	$ 34,668	$ 57,430	$ 47,029
Proved properties acquired	3,653	15,158	47,638
Exploration	16,480	15,907	14,811
Development	211,443	280,692	160,941
Asset retirement obligation	76	(7,629)	(3,613)
Total costs incurred	$ 266,320	$ 361,558	$ 266,806

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2019, by the year in which such costs were incurred:

	2019	2018	2017	2016 and Prior	Total
			(In thousands)		
Unproved properties acquired and wells in progress	$ 22,621	$ 54,780	$ 47,646	$ 127,827	252,874

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:

	2019	2018	2017
	(In thousands)		
Revenues	$ 314,925	$ 411,601	$ 347,285
Production costs	(116,051)	(113,810)	(107,332)
Depreciation, depletion, amortization, and impairment	(727,529)	(132,923)	(96,392)
	(528,655)	164,868	143,561
Income tax (expense) benefit	101,952	(42,915)	(56,376)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ (426,703)	$ 121,953	$ 87,185

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)			
2017				
Proved developed and undeveloped reserves:				
Beginning of year	15,696	34,482	405,579	117,774
Revision of previous estimates	730	4,325	38,330	11,444
Extensions and discoveries	2,235	4,520	49,321	14,975
Infill reserves in existing proved fields	1,632	5,779	52,270	16,123
Purchases of minerals in place	2,019	1,197	15,313	5,768
Production	(2,715)	(4,737)	(51,260)	(15,996)
Sales	(84)	(80)	(903)	(314)
End of year	19,513	45,486	508,650	149,774
Proved developed reserves:				
Beginning of year	12,724	28,502	347,121	99,079
End of year	14,862	33,358	388,446	112,961
Proved undeveloped reserves:				
Beginning of year	2,972	5,980	58,458	18,695
End of year	4,651	12,128	120,204	36,813
2018				
Proved developed and undeveloped reserves:				
Beginning of year	19,513	45,486	508,650	149,774
Revision of previous estimates [1]	180	(1,368)	(17,859)	(4,165)
Extensions and discoveries	3,250	5,149	75,806	21,033
Infill reserves in existing proved fields	1,898	2,795	23,778	8,656
Purchases of minerals in place	701	856	6,897	2,707
Production	(2,874)	(4,925)	(55,627)	(17,070)
Sales	(110)	(197)	(5,682)	(1,254)
End of year	22,558	47,796	535,963	159,681
Proved developed reserves:				
Beginning of year	14,862	33,358	388,446	112,961
End of year	15,192	33,515	377,216	111,576
Proved undeveloped reserves:				
Beginning of year	4,651	12,128	120,204	36,813
End of year	7,366	14,281	158,747	48,105
2019				
Proved developed and undeveloped reserves:				
Beginning of year	22,558	47,796	535,963	159,681
Revision of previous estimates [2]	(8,263)	(20,961)	(234,852)	(68,366)
Extensions and discoveries [2]	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)
End of year	12,196	23,030	220,187	71,924
Proved developed reserves:				
Beginning of year	15,192	33,515	377,216	111,576
End of year	12,196	23,030	220,187	71,924
Proved undeveloped reserves:				
Beginning of year	7,366	14,281	158,747	48,105
End of year	—	—	—	—

1. Natural gas revisions of previous estimates decreased primarily due to a decline in natural gas prices.
2. 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:

	2019	2018	2017
		(In thousands)	
Future cash flows	$ 1,386,777	$ 3,980,369	$ 3,347,396
Future production costs	(698,357)	(1,479,744)	(1,308,244)
Future development costs	—	(442,984)	(369,560)
Future income tax expenses	(321)	(307,916)	(234,152)
Future net cash flows	688,099	1,749,725	1,435,440
10% annual discount for estimated timing of cash flows	(226,390)	(766,047)	(628,270)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 461,709	$ 983,678	$ 807,170

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

	2019	2018	2017
		(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (200,233)	$ (297,791)	$ (239,953)
Net changes in prices and production costs	(508,066)	120,062	236,126
Revisions in quantity estimates and changes in production timing	(338,994)	(33,282)	87,239
Extensions, discoveries, and improved recovery, less related costs	53,123	234,172	102,965
Changes in estimated future development costs	311,190	19,535	(5,194)
Previously estimated cost incurred during the period	64,362	63,557	36,044
Purchases of minerals in place	6,416	23,416	51,686
Sales of minerals in place	(25,813)	(5,004)	(1,447)
Accretion of discount	110,571	89,753	57,517
Net change in income taxes	121,708	(31,674)	(33,389)
Changes in timing and other	(116,233)	(6,236)	(2,634)
Net change	(521,969)	176,508	288,960
Beginning of year	983,678	807,170	518,210
End of year	$ 461,709	$ 983,678	$ 807,170

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, 2019, future cash flows were computed by applying the unescalated 12-month average prices of $55.69 per barrel for oil, $23.19 per barrel for NGLs, and $2.58 per Mcf for natural gas (then adjusted for price differentials) relating to proved reserves and to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

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

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

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

None.

Item 9A. Controls and Procedures

Our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) (Disclosure Controls) or our internal control over financial reporting (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 CFO, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective as of December 31, 2019 at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There were no changes in ICFR during the quarter ended December 31, 2019, that materially affected our ICFR or are reasonably likely to materially affect it.

Management's Report on Internal Control Over Financial Reporting

Management of the company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management, and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

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

The company's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2019. In making this assessment, the company's management used the criteria set forth in *Internal Control— Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on their assessment, the company's management concluded that, as of December 31, 2019, the company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the company's internal control over financial reporting as of December 31, 2019, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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

Because our common stock is listed on the NYSE, our Chief Executive Officer was required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the NYSE corporate governance listing standards. Our Chief Executive Officer made his annual certification to that effect to the NYSE as of May 7, 2019. In addition, we have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our Chief Executive Officer and 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 February 28, 2020 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
Larry D. Pinkston	65	Chief Executive Officer since April 1, 2005, Director since January 15, 2004, President since August 1, 2003, Chief Operating Officer from February 24, 2004 to August 28, 2017, Vice President and Chief Financial Officer from May 1989 to February 24, 2004
Mark E. Schell	62	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	59	Chief Operating Officer since August 28, 2017, Senior Vice President from May 2, 2012 to November 27, 2017, Chief Financial Officer and Treasurer from February 24, 2004 to November 27, 2017, Vice President of Finance from August 2003 to February 24, 2004
G. Les Austin	54	Senior Vice President and Chief Financial Officer since November 27, 2017
David P. Dunham	40	Senior Vice President of Business Development since August 28, 2017, Vice President of Corporate Planning from January 2012 to August 28, 2017, Director of Corporate Planning from November 2007 to January 2012
John H. Cromling	72	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert H. Parks Jr.	65	Manager and President, Superior Pipeline Company, L.L.C. since June 1996
Frank Q. Young	50	Senior Vice President Exploration and Production Midcontinent of Unit Petroleum Company since 2012, Vice President - Central Division from June 2007, when he joined Unit Company, until 2012.

Mr. Pinkston joined the company in December 1981. He had served as Corporate Budget Director and Assistant Controller before being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President. He was elected a director of the company by the Board in January, 2004. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer and held this position until August 2017. In April 2005, he also began serving as Chief Executive Officer. Mr. Pinkston holds the offices of President and Chief Executive Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma.

Mr. Schell joined the company in January 1987, as its Secretary and General Counsel. In 2003, he was promoted to Senior Vice President. 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. He is also a member of the State Chamber of Oklahoma board of directors, a director of the Petroleum Alliance of Oklahoma, and serves on the board of advisors for the Greater Oklahoma City Chamber.

Mr. Merrill joined the company in August 2003 and served as its Vice President of Finance until February 2004 when he was elected to the position of Chief Financial Officer and Treasurer. In May 2012, he was promoted to Senior Vice President, a position he held until November 2017. In August 2017, he was promoted to Chief Operating Officer. From May 1999 through August 2003, Mr. Merrill served as Senior Vice President, Finance with TV Guide Networks, Inc. From July 1996 through May 1999 he was a Senior Manager with Deloitte & Touche LLP. From July 1994 through July 1996 he was Director of Financial Reporting and Special Projects for MAPCO, Inc. He began his career as an auditor with Deloitte, Haskins & Sells in 1983. Mr. Merrill received a Bachelor of Business Administration Degree in Accounting from the University of Oklahoma and is a Certified Public Accountant.

Mr. Austin joined the company in November 2017 as Senior Vice President and Chief Financial Officer of the company. Prior to coming to Unit, he served as Senior Vice President and Chief Financial Officer of Cypress Energy Partners, L.P.. From 2008 to 2011, he was the Senior Vice President and Chief Financial Officer of Ram Energy Resources, Inc. In 2011, he was promoted to Chief Operating Officer where he served until its sale in 2012. Before joining Ram Energy Resources, Inc., Mr. Austin was the Vice President of Finance and Chief Financial Officer of Matrix Service Company. He has also held various managerial and financial positions at Flint Energy Construction Co. and Ernst & Young, LLP. Mr. Austin has a bachelor's degree in accounting from Oklahoma State University and is a Certified Public Accountant.

Mr. Dunham joined the company in November 2007 as its Director of Corporate Planning. He was promoted to Vice President of Corporate Planning in January 2012. In August 2017, he was promoted to Senior Vice President of Business Development. From 2004 to November 2007, Mr. Dunham worked for Williams Power, serving as Manager of Structured Products. He worked for Leggett & Platt from 2003 to 2004, serving as a Mergers & Acquisitions Analyst. He 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.

Mr. Cromling joined Unit Drilling Company in 1997 as a Vice-President and Division Manager. In April 2005, he was promoted to the position of Executive Vice-President of Drilling for Unit Drilling Company. In 1980, he formed Cromling Drilling Company which managed and operated drilling rigs until 1987. From 1987 to 1997, Cromling Drilling Company provided engineering consulting services and generated and drilled oil and natural gas prospects. Prior to this, he was employed by Big Chief Drilling for 11 years and served as Vice-President. Mr. Cromling graduated from the University of Oklahoma with a degree in Petroleum Engineering.

Mr. Parks founded Superior Pipeline Company, L.L.C. in 1996. When Superior was acquired by the company in July 2004, he continued with Superior as one of its managers and as its President. From April 1992 through April 1996 Mr. Parks served as Vice-President—Gathering and Processing for Cimarron Gas Companies. From December 1986 through March 1992, he served as Vice-President—Business Development for American Central Gas Companies. Mr. Parks began his career as an engineer with Cities Service Company in 1978. He received a Bachelor of Science degree in Chemical Engineering from Rice University and his M.B.A. from the University of Texas at Austin.

Mr. Young joined Unit Petroleum Company in June 2007 as Vice President - Central Division. In 2012, he was promoted to Senior Vice President of Exploration and Production over Unit's Midcontinent assets and, in 2017, to Executive Vice President of Exploration and Production over Unit Petroleum Company. Before joining Unit, Mr. Young was employed by Anadarko Petroleum Corporation. He began his career with Anadarko in 1991 as a Production Engineer and, in 1994, began working as a Reservoir Engineer. In 1996, he was promoted to a Senior Asset Engineering role responsible for delineation and development of Anadarko's North African oil fields. In 1999, he was moved into a Senior Completions / Operations Engineering role responsible for development of gas fields in East Texas. In 2000, he was promoted to Division Engineer responsible for operations within Anadarko's Permian Division in West Texas. In 2002, he was promoted to Planning Manager for North America. In 2004, he was promoted to General Manager of Central Gulf of Mexico responsible for delineation and development of various Deepwater fields. Mr. Young holds a Bachelor of Science degree in Petroleum Engineering from Texas Tech University and a Master of Business Administration degree from Texas A&M University.

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

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2019, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	42,000 (2)	$ 48.56	2,039,520 (3)
Equity compensation plans not approved by security holders	—	—	—
Total	42,000	$ 48.56	2,039,520

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1. Shares awarded under all above plans may be newly issued, from our treasury, or acquired in the open market.
2. This number includes 42,000 stock options outstanding under the Non-Employee Directors' Stock Option Plan.
3. This number reflects the shares available for issuance under the Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the amended plan). The amended plan allows us to grant stock-based compensation to our employees and non-employee directors. A total of 7,230,000 shares of the company's common stock is authorized for issuance to eligible participants under the amended plan. No more than 2,000,000 of the shares available under the amended plan may be issued as "incentive stock options" and all of the shares available under this plan may be issued as restricted stock. In addition, shares related to grants that are forfeited, terminated, canceled, expire unexercised, or settled in such manner that all or some of the shares are not issued to a participant shall immediately become available for issuance.

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 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, 2019 and 2018
Consolidated Statements of Operations for the years ended December 31, 2019, 2018, and 2017
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2019, 2018, and 2017
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2017, 2018, and 2019
Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018, and 2017
Notes to Consolidated Financial Statements

2. ***Financial Statement Schedules:***

Included in Part IV of this report for the years ended December 31, 2019, 2018, and 2017:

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.

3.1	Restated Certificate of Incorporation of Unit Corporation (incorporated by reference to Exhibit 3.1 of Unit's Form 8-K, dated June 29, 2000).
3.1.1	Certificate of Amendment of Amended and Restated Certificate of Incorporation of the Company (filed as Exhibit 3.1 to Unit's Form 8-K, dated May 9, 2006 which is incorporated herein by reference).
3.2	By-laws of Unit Corporation, as amended and restated on June 17, 2014 (filed as Exhibit 3.3 to our Registration Statement on Form S-3 (File No. 333-202956), and incorporated by reference herein).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to Unit's Form S-3 (File No. 333-83551), which is incorporated herein by reference).
4.2	Indenture dated as of May 18, 2011, by and between the Company and Wilmington Trust FSB, as trustee (filed as Exhibit 4.1 to Unit's Form 8-K dated May 18, 2011, which is incorporated herein by reference).
4.3	First Supplemental Indenture (including form of note) dated as of May 18, 2011, by and among the Company, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and Wilmington Trust FSB as trustee (filed as Exhibit 4.2 to Unit's Form 8-K dated May 18, 2011, which is incorporated herein by reference).
4.4	Second Supplemental Indenture (including form of note) dated as of January 7, 2013, by and among the Registrant, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and Wilmington Trust, National Association as trustee (filed as Exhibit 4.10 to Unit's Post-Effective Amendment No.1 to the Registration Statement on Form S-3 dated February 16, 2016, which is incorporated herein by reference).
4.5	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (filed herein).
10.1	Amended and Restated Key Employee Change of Control Contract dated August 19, 2008 (filed as Exhibit 10.1 to Unit's Form 8-K dated August 25, 2008, which is incorporated herein by reference).
10.2	Senior Credit Agreement dated September 13, 2011 by and among the Company 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 to Unit's Form 8-K dated September 13, 2011, which is incorporated herein by reference).
10.3	First Amendment and Consent, dated September 5, 2012, to the Senior Credit Agreement by and among the Company 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 to Unit's Form 8-K dated September 5, 2012, which is incorporated herein by reference).

10.4	Second Amendment and Consent, dated April 10, 2015, to the Senior Credit Agreement by and among the Company 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 to Unit's Form 8-K dated April 10, 2015, which is incorporated herein by reference).
10.5	Third Amendment and Consent, dated April 8, 2016, to the Senior Credit Agreement by and among the Company 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 to Unit's Form 8-K dated April 8, 2016, which is incorporated herein by reference).
10.6	Fourth Amendment, dated April 2, 2018, to the Senior Credit Agreement by and among the Company 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 to Unit's Form 8-K dated April 6, 2018, which is incorporated herein by reference).
10.7	Fifth Amendment, dated October 18, 2018, to the Senior Credit Agreement by and among the Company 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 to Unit's Form 10-Q dated November 6, 2018, which is incorporated herein by reference).
10.8	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 herein by reference).
10.9	Gas Purchase Agreement dated November 21, 2011 by and between Superior Pipeline Company, L.L.C. and Sullivan and Company, L.L.C. (filed as Exhibit 10.1 to Unit's Form 8-K dated November 21, 2011, which is incorporated herein by reference).
10.10	Unit Corporation Employees' Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).
10.11	Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan dated May 6, 2015 (filed as Exhibit 10 to Unit's Form 8-K dated May 8, 2015, which is incorporated herein by reference).
10.12	Amendment Number 1 to the Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan (filed as Exhibit 10.1 to Unit's Form 8-K dated May 4, 2017, which is incorporated herein by reference).
10.13	Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.14	Annual Bonus Performance Plan entered into October 21, 2008 (filed as Exhibit 10.1 to Unit's Form 8-K dated October 23, 2008, which is incorporated herein by reference).
10.15	Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2016).
10.16	Unit Corporation 2000 Non-Employee Directors' Stock Option Plan as Amended and Restated August 25, 2004 (as amended on May 29, 2009 and filed as Exhibit 10.1 to Unit's Form 8-K dated May 29, 2009, which is incorporated herein by reference).
10.17	Unit Corporation 2000 Non-Employee Directors' Stock Option Plan as Amended and Restated August 25, 2004 (as amended on May 29, 2009 and filed as Exhibit 10.1 to Unit's Form 8-K dated May 29, 2009, which is incorporated herein by reference).
10.18	Special Separation Benefit Plan as amended December 8, 2015 (filed as Exhibit 10.2 to Unit's Form 8-K dated December 14, 2015, which is incorporated herein by reference).
10.19	Separation Benefit Plan for Senior Management as amended December 31, 2008 (filed as Exhibit 10.3 to Unit's Form 8-K dated January 6, 2009, which is incorporated herein by reference).
10.20	Unit Consolidated Employee Oil and Gas Limited Partnership Agreement (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.21	Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (incorporated by reference to Exhibit 10 of Unit's Annual Report on Form 10-K for the year ended December 31, 1999).
10.22	Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).
10.23	Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2001).
10.24	Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002).

10.25	Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2003).
10.26	Unit 2005 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2004).
10.27	Unit 2006 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2005).
10.28	Unit 2007 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2006).
10.29	Unit 2008 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2007).
10.3	Unit 2009 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2008).
10.31	Unit 2010 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2009).
10.32	Unit 2011 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2010).
10.33	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 herein by reference).
21	Subsidiaries of the Registrant (filed herein).
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (filed herein).
23.2	Consent of Ryder Scott Company, L.P. (filed herein).
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
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 (filed herein).
99.1	Ryder Scott Company, L.P. Summary Report (filed herein).
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, 2019	$ 2,531	$ 527	$ (726)	$ 2,332
Year ended December 31, 2018	$ 2,450	$ 81	$ —	$ 2,531
Year ended December 31, 2017	$ 3,773	$ 348	$ (1,671)	$ 2,450

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 16, 2020

By: /s/ LARRY D. PINKSTON

LARRY D. PINKSTON
President and Chief Executive Officer
(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 16th day of March, 2020.

Name	Title
/s/ J. MICHAEL ADCOCK **J. Michael Adcock**	Chairman of the Board and Director
/s/ LARRY D. PINKSTON **Larry D. Pinkston**	President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ LES AUSTIN **Les Austin**	Senior Vice President, Chief Financial Officer (Principal Financial Officer)
/s/ DON A. HAYES **Don A. Hayes**	Vice President, Chief Accounting Officer (Principal Accounting Officer)
/s/ GARY CHRISTOPHER **Gary Christopher**	Director
/s/ STEVEN B. HILDEBRAND **Steven B. Hildebrand**	Director
/s/ CARLA S. MASHINSKI **Carla S. Mashinski**	Director
/s/ WILLIAM B. MORGAN **William B. Morgan**	Director
/s/ LARRY C. PAYNE **Larry C. Payne**	Director
/s/ G. BAILEY PEYTON IV **G. Bailey Peyton IV**	Director
/s/ ROBERT SULLIVAN, JR. **Robert Sullivan, Jr.**	Director

DESCRIPTION OF THE REGISTRANT'S SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934

General

As of December 31, 2019, we are authorized to issue up to 180,000,000 shares of stock, including up to 175,000,000 shares of common stock, par value $0.20 per share, and up to 5,000,000 shares of preferred stock, par value $1.00 per share. As of December 31, 2019, we had 55,443,393 shares of common stock and no shares of preferred stock outstanding.

The following is a summary of the key terms and provisions of our equity securities. You should refer to the applicable provisions of our Second Restated Certificate of Incorporation, bylaws and the Delaware General Corporation Law for a complete statement of the terms and rights of our capital stock.

Common Stock

Voting rights. Each holder of common stock is entitled to one vote per share on each matter submitted to a vote of shareholders. Subject to the rights, if any, of the holders of any series of preferred stock pursuant to applicable law or the provision of the certificate of designation creating that series, all voting rights are vested in the holders of shares of common stock. Holders of shares of common stock have non-cumulative voting rights, which means that the holders of more than 50% of the shares voting for the election of directors can elect 100% of the directors, and the holders of the remaining shares voting for the election of directors will not be able to elect any directors.

Dividends. Dividends may be paid to holders of common stock when, as and if declared by the board of directors (the "Board") out of funds legally available for their payment, subject to the rights of holders of any preferred stock. We have not paid dividends on our common stock since the fourth quarter of 2015 and have no current plans to resume common stock dividends.

Rights upon liquidation. In the event of our voluntary or involuntary liquidation, dissolution or winding up, holders of our common stock will be entitled to share equally, in proportion to the number of shares of common stock held by them, in any of our assets available for distribution after the payment in full of all debts and distributions and after holders of all series of outstanding preferred stock, if any, have received their liquidation preferences in full.

Non-assessable. All outstanding shares of common stock are fully paid and non-assessable.

Other rights and preferences. Holders of common stock are not entitled to preemptive, conversion or exchange rights. Our common stock has no sinking fund or redemption provisions. Holders of common stock may act by unanimous written consent.

Listing. Our outstanding shares of common stock are listed on the New York Stock Exchange under the trading symbol "UNT."

Preferred Stock

The following description of the terms of the preferred stock sets forth certain general terms and provisions of our authorized preferred stock. If we offer preferred stock, a description will be filed with the Securities and Exchange Commission and the specific designations and rights, as determined by the Board, will be described in such filing, including the following terms:

- the series, the number of shares offered and the liquidation value of the preferred stock;

- the price at which the preferred stock will be issued;
- the dividend rate, the dates on which the dividends will be payable and other terms relating to the payment of dividends on the preferred stock;
- the liquidation preference of the preferred stock;
- the voting rights of the preferred stock, if any;
- whether the preferred stock is redeemable or subject to a sinking fund, and the terms of any such redemption or sinking fund;
- whether the preferred stock is convertible or exchangeable for any other securities, and the terms of any such conversion; and
- any additional rights, preferences, qualifications, limitations and restrictions of the preferred stock.

Except where otherwise set forth in a resolution of the Board providing for the issuance of any series of preferred stock, the number of shares comprising such series may be increased or decreased (but not below the number of shares then outstanding) from time to time by like action of the Board. The shares of preferred stock of any one series shall be identical with the other shares in the same series in all respects except as to the dates from and after which dividends thereon shall cumulate, if cumulative.

The description of the terms of the preferred stock to be set forth in the applicable filing will not be complete and will be subject to and qualified in its entirety by reference to the certificate of designation relating to the applicable series of preferred stock.

Undesignated preferred stock may enable the Board to render more difficult or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and to thereby protect the continuity of our management. The issuance of shares of preferred stock may adversely affect the rights of holders of our common stock. For example, any preferred stock issued may rank prior to our common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights and may be convertible into shares of common stock. As a result, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock or any existing preferred stock.

Any preferred stock will, when issued, be fully paid and non-assessable.

Certain Other Possible Anti-takeover Provisions

Our by-laws, charter and Delaware law contain certain provisions that might be characterized as anti-takeover provisions. These provisions may make it more difficult to acquire control of us or remove our management.

Classified Board of Directors

Our by-laws provides for our board of directors to be divided into three classes of directors serving staggered three-year terms, with the number of directors in each class to be as nearly equal as possible. As a result, and assuming all classes have the same number of directors, only one-third of our directors are elected each year.

Fair Price Provisions

Our charter also contains certain "fair price provisions" designated to provide safeguards for stockholders when an "interested stockholder" (defined as a stockholder owning 5% or more of our voting stock) attempts to effect a "business combination" with us. The term "business combination" includes:

- any merger or consolidation of us involving the interested stockholder;
- certain disposition of our assets;

- any issuance of our securities meeting certain threshold amounts, to the interested stockholder;
- adoption of any plan of liquidation or dissolution of us proposed by the interested stockholder; and
- any reclassification of our securities having the effect of increasing the proportionate share of ownership of the interested stockholder.

In general, a business combination between us and the interested stockholder must be approved by the affirmative vote of 80% of the outstanding voting stock unless the transaction is approved by a majority of the members of the Board of Directors who are not affiliated with the interested stockholder or certain minimum price and form of consideration requirements are satisfied.

Delaware Business Combination Statute

We are incorporated under the laws of the State of Delaware. Section 203 of the Delaware General Corporation Law prevents an "interested stockholder" (defined as a stockholder owning 15% or more of a corporation's voting stock) from engaging in a business combination with that corporation for a period of three years from the date the stockholder became an interested stockholder unless:

- the corporation's board of directors had earlier approved either the business combination or the transaction by which the stockholder became an interested stockholder;
- upon attaining that status, the interested stockholder had acquired at least 85% of the corporation's voting stock (not counting shares owned by persons who are directors and also officers); or
- the business combination is later approved by the board of directors and authorized by a vote of two-thirds of the stockholders (not including the shares held by the interested stockholder).

Since we have not amended our charter or by-laws to exclude the application of Section 203, its provisions apply to us. Accordingly, Section 203 may inhibit an interested stockholder's ability to acquire additional shares of common stock or otherwise engage in a business combination with us.

Advance Notice for Raising Business or Making Nominations at Meetings

Our by-laws establish an advance notice procedure for stockholder proposals to be brought before an annual meeting of stockholders and for nominations by stockholders of candidates for election as directors at an annual or special meeting at which directors are to elected.

Only such business may be conducted at an annual meeting of stockholders as has been brought before the meeting by, or at the direction of, the board of directors or by a stockholder who has given to our secretary timely written notice, in proper form, of the stockholder's intention to bring that business before the meeting. Only persons who are nominated by, or at the direction of, the board of directors, or who are nominated by a stockholder who has given timely written notice, in proper form, to the secretary prior to a meeting at which directors are to be elected will be eligible for election as directors. The person presiding at the meeting will have the authority to make determinations whether a stockholder's notice complies with the procedures in our by-laws.

To be timely, notice of business to be brought before an annual meeting or nominations of candidates for election as directors at an annual meeting is generally required to be received by our secretary not later than 90 days nor earlier than 120 days prior to the first anniversary of the prior year's annual meeting date.

The notice of any nomination for election as a director is required to set forth the information regarding that person required in our by-laws as well as by paragraphs (a), (e), and (f) of Item 401 of regulation S-K adopted by the SEC.

Transfer Agent and Registrar

The Transfer Agent and Registrar for our common stock AST Transfer Services.

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, 2019 and excludes subsidiaries which are primarily inactive or taken singly, or as a group, do not constitute significant subsidiaries:

Subsidiary	State or Province of Incorporation	Percentage Owned
Unit Drilling Company	Oklahoma	100%
Unit Petroleum Company	Oklahoma	100%
Superior Pipeline Company, L.L.C.	Oklahoma	50%

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-223649) and Form S-8 (Nos. 333-38166, 333-135194, 333-137857, 333-166605, 333-181922, 333-205033, 333-208394 and 333-218606) of Unit Corporation of our report dated March 16, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 16, 2020

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to incorporation by reference in the Registration Statements on Form S-3 (File No. 333-223649), Form S-4 (File No. 333-234509), and Form S-8 (File Nos. 333-38166, 333-135194, 333-137857, 333-166605, 333-181922, 333-205033, 333-208394, and 333-218606) of Unit Corporation of the reference to our reserves audit report for Unit Corporation dated March 6, 2020, which appears in the December 31, 2019 annual report on Form 10-K of Unit Corporation.

/s/ RYDER SCOTT COMPANY, L.P.

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

Houston, Texas
March 16, 2020

Exhibit 31.1

302 CERTIFICATIONS

I, Larry D. Pinkston, 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 16, 2020

/s/ Larry D. Pinkston
LARRY D. PINKSTON
Chief Executive Officer and Director

Exhibit 31.2

302 CERTIFICATIONS

I, Les Austin, 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 16, 2020

/s/ Les Austin
LES AUSTIN
Senior Vice President and Chief Financial Officer

Exhibit 32

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

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

The Annual Report on Form 10-K for the year ended December 31, 2019 (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, 2019 and December 31, 2018 and for the years ended December 31, 2019, 2018, and 2017.

Dated: March 16, 2020

By: /s/ Larry D. Pinkston
Larry D. Pinkston
Chief Executive Officer and Director

Dated: March 16, 2020

By: /s/ Les Austin
Les Austin
Senior Vice President and Chief Financial Officer

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

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

UNIT CORPORATION

Estimated

Net Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2019

\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

March 6, 2020

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 of the proved reserves as of December 31, 2019 prepared by Unit's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on March 6, 2020 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, 2019. The properties reviewed by Ryder Scott incorporate 316 reserves determinations and are located in the states of Kansas, Louisiana, Montana, North Dakota, Oklahoma and Texas. The wells for which estimates of reserves were audited by Ryder Scott were selected by Unit.

This revised reserves audit replaces the previous Ryder Scott reserves audit as of December 31, 2019 with audit letter dated January 29, 2020. Unit informed us that they have revised their development plan which requires a revised audit. 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, 2019. Based on the estimates of total net proved reserves prepared by Unit, the reserves audit conducted by Ryder Scott addresses 81 percent of the total proved developed net liquid hydrocarbon reserves and 75 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, 2019. Unit informed Ryder Scott that the selected entities included approximately 86% of Unit's discounted future net income at 10% for the total proved developed 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 reserve 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, 2019 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, 2019, 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, 2019

	Total Proved Total Proved
Net Reserves of Properties Audited by Ryder Scott	
Oil/Condensate – MBarrels	10,270
Plant Products – MBarrels	18,237
Gas - MMcf	164,689
Net Reserves of Properties Not Audited by Ryder Scott	
Oil/Condensate – MBarrels	1,926
Plant Products – MBarrels	4,793
Gas - MMcf	55,498
Total Net Reserves	
Oil/Condensate – MBarrels	12,196
Plant Products – MBarrels	23,030
Gas - MMcf	220,187

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). 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 AND GUIDELINES" in this report. No proved developed non-producing 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 that the quantities will be recovered."

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

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, the volumetric method, analogy, or a combination of methods. Approximately 86 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 and material balance which utilized extrapolations of historical production and pressure data available through September - December, 2019, 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 14 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. 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, 2019 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	$55.69/Bbl	$53.76/Bbl
	NGLs	Mont Belvieu Non TET Propane	$23.19/Bbl	$14.60/Bbl
	Gas	Henry Hub	$2.58/MMBTU	$1.78/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, recompletion and development costs, development plans, 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, 2019 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 19 percent of the total proved net liquid hydrocarbon reserves and 25 percent of the total proved net gas reserves based on estimates prepared by Unit as of December 31, 2019.

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]

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Professional Qualifications of Primary Technical Person

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

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

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

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Paradiso fulfills. As part of his 2019 continuing education hours, Mr. Paradiso attended 6 hours of formalized training during the 2019 RSC Reserves Conference relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal RegisterMr. Paradiso attended an additional 31 hours of formalized in-house training during 2019 covering such topics as 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 more than 40 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Paradiso has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

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

PREAMBLE

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

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends 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 after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

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

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

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

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

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

RESERVES (SEC DEFINITIONS)

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

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

<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.

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

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

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

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