UNIT CORP
Form 10-Q
May 02, 2019

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20211,4641,6233,5053,902P3YP3YP3Y————1.060,00040,00020,00010,00030,00030,00020,0002.633.034,00051.2561.25

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 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)	(I.R.S. Employer Identification No.)

8200 South Unit Drive, Tulsa, Oklahoma	**74132**
(Address of principal executive offices)	(Zip Code)

(918) 493-7700
(Registrant's telephone number, including area code)
None
(Former name, former address and former fiscal year, if changed since last report)

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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [x] Accelerated filer [ ] 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 April 19, 2019, 55,467,987 shares of the issuer's common stock were outstanding.
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	UNT	NYSE

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Forward-Looking Statements

This report contains “forward-looking statements” – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document that addresses activities, events or developments we expect or anticipate will or may occur, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” and 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 will automatically update and supersede information in this report.

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

•the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
•prices for oil, natural gas liquids (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 legal proceedings involving us 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 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;
•our projected production guidelines for the year;
•our anticipated capital budgets;
•our financial condition and liquidity;
•the number of wells our oil and natural gas segment plans to drill or rework during the year; and
•our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

These statements are based on assumptions and analyses made by us based on 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;
•putative class action lawsuits that may cause 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 intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after this document to reflect unanticipated events.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2019		December 31, 2018	
	(In thousands except share amounts)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	3,891	$	6,452
Accounts receivable, net of allowance for doubtful accounts of $2,531 at both March 31, 2019 and December 31, 2018, respectively	93,875		119,397	
Materials and supplies	495		473	
Curent derivative asset (Note 10)	3,464		12,870	
Income taxes receivable	2,054		2,054	
Assets held for sale (Note 3)	19,728		22,511	
Prepaid expenses and other	7,504		6,602	
Total current assets	131,011		170,359	
Property and equipment:				
Oil and natural gas properties on the full cost method:				
Proved properties	6,104,092		6,018,568	
Unproved	339,957		330,216	

properties not being amortized				
Drilling equipment	1,279,735		1,284,419	
Gas gathering and processing equipment	781,970		767,388	
Saltwater disposal systems	69,010		68,339	
Corporate land and building	59,080		59,081	
Transportation equipment	30,327		29,524	
Other	57,624		57,507	
	8,721,795		8,615,042	
Less accumulated depreciation, depletion, amortization, and impairment	6,225,220		6,182,726	
Net property and equipment	2,496,575		2,432,316	
Goodwill	62,808		62,808	
Right of use asset (Note 12)	4,551		—	
Other assets	34,235		32,570	
Total assets [1]	$	2,729,180	$	2,698,053

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.
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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	March 31, 2019		December 31, 2018	
	(In thousands except share amounts)			
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	132,899	$	149,945
Accrued liabilities (Note 5)	48,084		49,664	
Current operating lease liability (Note 12)	2,369		—	
Current portion of other long-term liabilities (Note 6)	14,310		14,250	
Total current liabilities	197,662		213,859	
Long-term debt less debt issuance costs (Note 6)	685,031		644,475	
Non-current derivative liability (Note 10)	475		293	
Operating lease liability (Note 12)	1,952		—	
Other long-term liabilities (Note 6)	103,832		101,234	
Deferred income taxes	144,369		144,748	
Commitments and contingencies (Note 13)	—		—	
Shareholders' equity:				
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—		—	
Common stock, $.20 par value, 175,000,000 shares authorized, 55,467,987 and 54,055,600 shares issued as of March 31, 2019 and December 31, 2018, respectively	10,578		10,414	

Capital in excess of par value	633,361		628,108	
Accumulated other comprehensive loss (Note 15)	(457)		(481)	
Retained earnings	749,510		752,840	
Total shareholders' equity attributable to Unit Corporation	1,392,992		1,390,881	
Non-controlling interests in consolidated subsidiaries	202,867		202,563	
Total shareholders' equity	1,595,859		1,593,444	
Total liabilities[1] and shareholders' equity	$	2,729,180	$	2,698,053

(1)Unit Corporation's consolidated total assets as of March 31, 2019 include total current and long-term assets of its variable interest entity (VIE) (Superior Pipeline Company, L.L.C.) of $28.9 million and $428.1 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated total liabilities as of March 31, 2019 include total current and long-term liabilities of the VIE of $36.0 million and $14.0 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 total current and long-term assets of the VIE 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 total 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 14 – Variable Interest Entity Arrangements.

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended March 31,	
	2019	2018
	(In thousands except per share amounts)	
Revenues:		
Oil and natural gas	$ 86,095	$ 103,099
Contract drilling	51,155	45,989
Gas gathering and processing	52,441	56,044
Total revenues	189,691	205,132
Expenses:		
Operating costs:		
Oil and natural gas	32,714	35,962
Contract drilling	31,401	31,667
Gas gathering and processing	39,355	41,604
Total operating costs	103,470	109,233
Depreciation, depletion, and amortization	62,126	57,066
General and administrative	9,741	10,762
(Gain) loss on disposition of assets	1,615	(161)
Total operating expenses	176,952	176,900
Income from operations	12,739	28,232
Other income (expense):		
Interest, net	(8,538)	(10,004)
Loss on derivatives	(6,932)	(6,762)
Other, net	5	6
Total other income (expense)	(15,465)	(16,760)
Income (loss) before income	(2,726)	11,472

taxes				
Income tax expense (benefit):				
Deferred	(444)		3,607	
Total income taxes	(444)		3,607	
Net income (loss)	(2,282)		7,865	
Net income attributable to non-controlling interest	1,222		—	
Net income (loss) attributable to Unit Corporation	$	(3,504)	$	7,865
Net income (loss) attributable to Unit Corporation per common share:				
Basic	$	(0.07)	$	0.15
Diluted	$	(0.07)	$	0.15

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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

	Three Months Ended March 31, 2019	2018
	(In thousands)	
Net income (loss)	$ (2,282)	$ 7,865
Other comprehensive income (loss), net of taxes:		
Unrealized gain (loss) on securities, net of tax of $7 and ($58)	24	(176)
Comprehensive income (loss)	(2,258)	7,689
Less: Comprehensive income attributable to non-controlling interest	1,222	—
Comprehensive income (loss) attributable to Unit Corporation	$ (3,480)	$ 7,689

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (UNAUDITED)

	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	(In thousands except per share amounts)					
Balances, December 31, 2018	$ 10,414	$ 628,108	$ (481)	$ 752,840	$ 202,563	1,593,444
Cumulative effect adjustment for adoption of ASUs (Notes 1 and 12)	—	—	—	174	—	174
Net income (loss)	—	—	—	(3,504)	1,222	(2,282)
Other comprehensive gain (net of tax of $7)	—	—	24	—	—	24
Total comprehensive loss						(2,258)
Distributions to non-controlling interest	—	—	—	—	(918)	(918)
Activity in employee compensation plans (1,412,387 shares)	164	5,253	—	—	—	5,417
Balances, March 31, 2019	$ 10,578	$ 633,361	$ (457)	$ 749,510	$ 202,867	$ 1,595,859

	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	(In thousands except per share amounts)					
Balances, December 31, 2017	$ 10,280	$ 535,815	$ 63	$ 799,402	$ —	$ 1,345,560
Cumulative effect	—	—	13	(1,274)	—	(1,261)

adjustment for adoption of ASUs						
Net income	—	—	—	7,865	—	7,865
Other comprehensive loss (net of tax of ($58))	—	—	(176)	—	—	(176)
Total comprehensive income						7,689
Activity in employee compensation plans (1,166,227 shares)	123	5,189	—	—	—	5,312
Balances, March 31, 2018	$ 10,403	$ 541,004	$ (100)	$ 805,993	$ —	$ 1,357,300

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2019	2018
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	$ (2,282)	$ 7,865
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	62,126	57,066
Amortization of debt issuance costs and debt discount (Note 6)	556	546
Loss on derivatives (Note 10)	6,932	6,762
Cash proceeds (payments) on derivatives settled, net (Note 10)	2,656	(2,073)
Deferred tax expense	(444)	3,607
(Gain) loss on disposition of assets	1,615	(161)
Stock compensation plans	5,134	6,609
Contract assets and liabilities, net (Note 2)	(700)	(1,192)
Other, net	573	937
Changes in operating assets and liabilities increasing (decreasing)		

cash:		
Accounts receivable	18,830	8,005
Accounts payable	(20,848)	(10,716)
Material and supplies	(22)	50
Accrued liabilities	2,749	6,757
Other, net	203	(494)
Net cash provided by operating activities	77,078	83,568
INVESTING ACTIVITIES:		
Capital expenditures	(122,507)	(90,249)
Producing properties and other acquisitions	(1,580)	—
Proceeds from disposition of assets	3,190	22,084
Net cash used in investing activities	(120,897)	(68,165)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	109,800	67,400
Payments under credit agreement	(69,800)	(97,700)
Payments on finance leases	(985)	(946)
Distributions to non-controlling interest	(918)	—
Book overdrafts	3,161	15,894
Net cash provided by (used in) financing activities	41,258	(15,352)
	(2,561)	51

Net increase (decrease) in cash and cash equivalents				
Cash and cash equivalents, beginning of period		6,452		701
Cash and cash equivalents, end of period	$	3,891	$	752

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) - CONTINUED

	Three Months Ended March 31, 2019	2018
	(In thousands)	
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	$ (3,307)	$ (1,731)
Income taxes	—	—
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	(641)	(13,238)
Non-cash (addition) reduction to oil and natural gas properties related to asset retirement obligations	(3,070)	6,340

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The unaudited condensed consolidated financial statements in this report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company," "Unit," "we," "our," "us," or like terms refer to Unit Corporation, a Delaware corporation, and one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires. We consolidate the activities of Superior Pipeline Company, L.L.C. (Superior), a 50/50 joint venture between Unit Corporation and SP Investor Holdings, LLC, which qualifies as a Variable Interest Entity (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 our 50% ownership, to direct those activities that most significantly affect the economic performance of Superior as further described in Note 14 – Variable Interest Entity Arrangements.

The condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This report should be read with the audited consolidated financial statements and notes in our Form 10-K, filed February 26, 2019, for the year ended December 31, 2018.

In the opinion of our management, the unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state:

- Balance Sheets at March 31, 2019 and December 31, 2018;
- Statements of Operations for the three months ended March 31, 2019 and 2018;
- Statements of Comprehensive Income (Loss) for the three months ended March 31, 2019 and 2018;
- Statements of Changes in Shareholders' Equity for the three months ended March 31, 2019 and 2018; and
- Statements of Cash Flows for the three months ended March 31, 2019 and 2018.

Our financial statements are prepared in conformity with GAAP, which requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and notes. Actual results may differ from those estimates. Results for the three months ended March 31, 2019 and 2018 are not necessarily indicative of the results we may realize for the full year of 2019, or that we realized for the full year of 2018.

Certain amounts in this report for prior periods have been reclassified to conform to current year presentation. There was no impact to consolidated net income (loss) or shareholders' equity.

Accounting Changes - Recent Accounting Pronouncements - Adopted

As of January 1, 2019, we adopted *Leases - Topic 842* (ASC 842) 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. This new lease standard is explained further in Note 8 – New Accounting Pronouncements.

The additional disclosures required by ASC 842 have been included in Note 12 – Leases.

NOTE 2 – 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 16 – Industry Segment Information). Revenue from the oil and natural gas segment is from sales of our oil and natural gas production. Revenue from the contract drilling segment 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.

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Oil and Natural Gas Revenues

Certain costs—as either a deduction from revenue or as an expense—is 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.

Contract Drilling Revenues

We evaluated the mobilization and de-mobilization charges due on our outstanding drilling contracts. The impact of those charges to the financial statements was immaterial. As of March 31, 2019, we had 32 contract drilling contracts with terms ranging from two months to almost three years.

Most 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

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. The following tables show the changes in our mid-stream contract asset and contract liability balances during the three months ended March 31, 2019:

Contract Assets	**Amount**	
	(In thousands)	
Balance at December 31, 2018 [1]	$	13,164
Amounts invoiced in excess of revenue recognized	(9)	
Balance at March 31, 2019 [1]	$	13,155

1.At December 31, 2018, the total contract assets are included in prepaid expenses and other and other assets of $0.3 million and $12.9 million, respectively, in our Condensed Consolidated Balance Sheet. At March 31, 2019, the total contract assets included prepaid expenses and other and other assets of $1.8 million and $11.4 million, respectively, in our Condensed Consolidated Balance Sheet.

Contract Liabilities	**Amount**	
	(In thousands)	
Balance at December 31, 2018	$	9,882

Revenue recognized included in beginning balance	(709)	
Balance at March 31, 2019	$	9,173

1.At December 31, 2018, the total contract liabilities are included in current portion of other long-term liabilities and other long-term liabilities of $2.9 million and $7.0 million, respectively, in our Condensed Consolidated Balance Sheet. At March 31, 2019, the total contract liabilities included current portion of other long-term liabilities and other long-term liabilities of $2.9 million and $6.3 million, respectively, in our Condensed Consolidated Balance Sheet.

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.

Contract	**Remaining Term of Contract**	**April - December 2019**	**2020**	**2021**	**2022**	**Total Remaining Impact to Revenue**
		(In thousands)				
Demand fee contracts	3-4 years	$ 1,932	$ (3,781)	$ (3,507)	$ 1,374	$ (3,982)

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NOTE 3 – DIVESTITURES

Oil and Natural Gas

We sold non-core oil and natural gas assets, net of related expenses, for $0.6 million during the first three months of 2019, compared to $21.7 million during the first three months of 2018. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling

In December 2018, we removed 41 drilling rigs and other equipment from service. We estimated the fair value of the 41 drilling rigs based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a non-cash write-down of approximately $147.9 million, pre-tax. During the first quarter of 2019, we sold three of these drilling rigs and some of the other equipment to unaffiliated third parties. The proceeds of those sales, less costs to sell, was less than the applicable $2.8 million net book value resulting in a loss of $0.6 million. The remaining drilling rigs and equipment not sold will be marketed for sale throughout 2019 and remain classified as assets held for sale. The net book value of those assets is $19.7 million.

NOTE 4 – EARNINGS (LOSS) PER SHARE

Information related to the calculation of earnings (loss) per share attributable to Unit Corporation follows:

	Earnings (Loss) (Numerator)		Weighted Shares (Denominator)	Per-Share Amount	
	(In thousands except per share amounts)				
For the three months ended March 31, 2019					
Basic loss attributable to Unit Corporation per common share	$	(3,504)	52,557	$	(0.07)
Effect of dilutive stock options and restricted stock	—		—	—	
Diluted loss attributable to Unit Corporation per common share	$	(3,504)	52,557	$	(0.07)
For the three months ended March 31,					

2018						
Basic earnings attributable to Unit Corporation per common share	$	7,865	51,730	$	0.15
Effect of dilutive stock options and restricted stock	—		542	—	
Diluted earnings attributable to Unit Corporation per common share	$	7,865	52,272	$	0.15

Due to the net loss for the three months ended March 31, 2019, approximately 279,000 weighted average shares related to stock options and restricted stock were antidilutive and were excluded from the earnings per share calculation above.

The following table shows the number of stock options (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended March 31,			
	2019		**2018**	
Stock options	56,000		87,500	
Average exercise price	$	44.73	$	51.34

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NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of:

	March 31, 2019	December 31, 2018
	(In thousands)	
Interest payable	$ 17,354	$ 6,635
Employee costs	10,356	22,056
Lease operating expenses	7,961	12,756
Taxes	4,059	1,378
Third-party credits	2,974	2,129
Other	5,380	4,710
Total accrued liabilities	$ 48,084	$ 49,664

NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

As of the date indicated, our long-term debt consisted of the following:

	March 31, 2019	December 31, 2018
	(In thousands)	
Unit credit agreement with an average interest rate of 4.0% at March 31, 2019	$ 40,000	$ —
Superior credit agreement	—	—
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	690,000	650,000
Less: unamortized discount	(1,464)	(1,623)
	(3,505)	(3,902)

Less: debt issuance costs, net				
Total long-term debt	$	685,031	$	644,475

Unit Credit Agreement. On October 18, 2018, we amended our Senior Credit Agreement (Unit credit agreement) which is scheduled to mature on October 18, 2023. 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. Our elected commitment amount is $425.0 million. Our borrowing base is $425.0 million. We are currently 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 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.

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, under which we granted 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 borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime 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.

At our election, any part of the outstanding debt under the Unit credit agreement can be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the LIBOR base for the term plus 1.50% to 2.50% depending on the level of debt as a percentage of the borrowing base and 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 but in no event less than

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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 March 31, 2019, we had $40.0 million outstanding borrowings under the Unit credit agreement.

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 Unit credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of March 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 (Superior credit agreement). The amounts borrowed under the Superior credit agreement bear annual interest at a rate, at Superior’s option, equal to (a) LIBOR plus the applicable margin of 2.00% to 3.25% or (b) the alternate base rate (greater of (i) the federal funds rate plus 0.5%, (ii) the prime rate, and (iii) third day LIBOR plus 1.00%) plus the applicable margin of 1.00% to 2.25%. The obligations under the Superior credit agreement are secured by, 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 currently 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 March 31, 2019, Superior was in compliance with these covenants.

The borrowings under the Superior credit agreement will fund capital expenditures and acquisitions, provide general working capital, and for letters of credit for Superior. As of March 31, 2019, we had no outstanding borrowings under the Superior credit agreement.

Superior's credit agreement is not guaranteed by Unit.

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6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes) outstanding. Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes mature on May 15, 2021. In issuing the Notes, we incurred fees of $14.7 million 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 of and providing for issuing the Notes. The Guarantors are most of 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, occasionally, 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 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 of the Notes as of March 31, 2019.

We may from time to time seek to retire or purchase our outstanding Note debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2019	**December 31, 2018**
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 67,840	$ 64,208
Workers’ compensation	12,226	12,738
	10,395	11,380

Finance lease obligations		
Contract liability	9,173	9,881
Separation benefit plans	9,291	8,814
Deferred compensation plan	5,845	5,132
Gas balancing liability	3,372	3,331
	118,142	115,484
Less current portion	14,310	14,250
Total other long-term liabilities	$ 103,832	$ 101,234

Estimated annual principal payments under the terms of our long-term debt and other long-term liabilities during the five successive twelve-month periods beginning April 1, 2019 (and through 2024) are $14.3 million, $47.8 million, $656.9 million, $3.6 million, and $42.3 million, respectively.

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NOTE 7 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All our AROs relate to the plugging costs associated with our oil and gas wells.

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

	Three Months Ended March 31, 2019	2018
	(In thousands)	
ARO liability, January 1:	$ 64,208	$ 69,444
Accretion of discount	562	659
Liability incurred	3,116	118
Liability settled	(1,636)	(1,626)
Liability sold	(549)	(81)
Revision of estimates (1)	2,139	(4,751)
ARO liability, March 31:	67,840	63,763
Less current portion	1,742	1,477
Total long-term ARO	$ 66,098	$ 62,286

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.

NOTE 8 – NEW ACCOUNTING PRONOUNCEMENTS

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.

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, and early adoption is permitted. This amendment will not have a material impact on our 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 will be 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 12 – Leases.

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NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended March 31,	
	2019	2018
	(In millions)	
Recognized stock compensation expense	$ 3.8	$ 5.5
Capitalized stock compensation cost for our oil and natural gas properties	0.6	0.4
Tax benefit on stock-based compensation	0.9	1.3

The remaining unrecognized compensation cost related to unvested awards at March 31, 2019 is approximately $30.4 million, of which $4.2 million is anticipated to be capitalized. The weighted average period over which this cost will be recognized is 1.0 year.

Our 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. 7,230,000 shares of the company's common stock are authorized for issuance to eligible participants under the amended plan with 2,000,000 shares being the maximum number of shares that can be issued as "incentive stock options."

We granted no SARs or stock options during either of the three month periods ending March 31, 2019 or 2018. This table shows the fair value of restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended March 31, 2019		Three Months Ended March 31, 2018	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	925,673	424,070	839,498	362,070
Non-employee directors	—	—	—	—
	925,673	424,070	839,498	362,070
Estimated fair value (in millions):(1)				
Employees	$ 14.6	$ 7.1	$ 16.1	$ 7.3

Non-employee directors	—	—	—	—
	$ 14.6	$ 7.1	$ 16.1	$ 7.3
Percentage of shares granted expected to be distributed:				
Employees	95 %	64 %	95 %	63 %
Non-employee directors	N/A	N/A	N/A	N/A

1.The performance shares represent 100% of the grant date fair value. (We recognize the grant date fair value minus estimated forfeitures.)

The time vested restricted stock awards granted during the first three months of 2019 and 2018 are being recognized over a three-year vesting period. During the first quarter of 2019 and 2018, two performance vested restricted stock awards were 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 (TSR) 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 subject to 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 TSR performance criteria at March 31, 2019, the participants are estimated to receive 28% of the 2019 and 74% of the 2018 performance-based shares. The CFTA performance measurement at March 31, 2019 was assessed to vest at target or 100%. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2019 awards for the first three months of 2019 was $1.0 million.

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NOTE 10 – DERIVATIVES

Commodity Derivatives

We have signed various types of derivative transactions covering some of our projected natural gas 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 March 31, 2019, these hedges made up our derivative transactions:

•*Swaps.* We receive or pay a fixed price for the commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

•*Basis/Differential Swaps.* We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the commodity and pay or receive the published index price at the specified delivery point. We use basis/differential swaps to hedge the price risk between NYMEX and its physical delivery points.

•*Collars.* A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

•*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 transactions. We do not engage in derivative transactions not otherwise tied to our projected production. Any changes in the fair value of our derivative transactions before maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Unaudited Condensed Consolidated Income Statements.

At March 31, 2019, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'19 – Oct'19	Natural gas – swap	60,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Nov'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Apr'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Apr'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Apr'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Apr'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
		4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

Apr'19 – Dec'19	Crude oil – three-way collar

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The following tables present the fair values and locations of the derivative transactions recorded in our Unaudited Condensed Consolidated Balance Sheets:

	Balance Sheet Location	Derivative Assets Fair Value March 31, 2019	December 31, 2018
		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	$ 3,464	$ 12,870
Long-term	Non-current derivative asset	—	—
Total derivative assets		$ 3,464	$ 12,870

	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2019	December 31, 2018
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liability	$ —	$ —
Long-term	Non-current derivative liability	475	293
Total derivative liabilities		$ 475	$ 293

All our counterparties are subject to master netting arrangements. If we have a legal right of set-off, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets.

Following is the effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations for the three months ended March 31:

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative 2019	2018
		(In thousands)	
		$ (6,932)	$ (6,762)

Commodity derivatives	Loss on derivatives (1)				
Total		$	(6,932)	$	(6,762)

1.Amounts settled during the 2019 and 2018 periods include net proceeds of $2.7 million and net payments of $2.1 million, respectively.

NOTE 11 – FAIR VALUE MEASUREMENTS

The estimated fair value of our available-for-sale securities, reflected on our Unaudited Condensed Consolidated Balance Sheets as non-current other assets, is based on market quotes. The following is a summary of available-for-sale securities:

	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(In thousands)			
Equity Securities:				
March 31, 2019	$ 830	$ —	$ 605	$ 225
December 31, 2018	$ 830	$ —	$ 636	$ 194

During the second quarter of 2017, we received available-for-sale securities for early termination fees associated with a long-term drilling contract. We evaluate the marketability of those equity securities to determine if any decline in fair value below cost is other-than-temporary. If a decline in fair value below cost is determined to be other-than-temporary, an

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impairment charge will be recorded, and a new cost basis established. We use several factors to determine whether a loss is other-than-temporary. These factors include, but are not limited to, (i) the time a security is in an unrealized loss position, (ii) the extent to which fair value is less than cost, (iii) the financial condition and near-term prospects of the issuer, and (iv) our intent and ability to hold the security for a period of time sufficient to allow for any anticipated recovery in fair value.

Fair value is defined as the amount that would be received from the sale of an asset or paid for transferring 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 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 developed based on the best information available and may include our own internal data.

The inputs available to us 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:

	March 31, 2019				
	Level 1	**Level 2**	**Level 3**	**Effect of Netting**	**Net Amounts Presented**
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$ —	$ 1,727	$ 3,098	$ (1,361)	$ 3,464
Liabilities	—	(1,818)	(18)	1,361	(475)
Total commodity derivatives	—	(91)	3,080	—	2,989
Equity securities	225	—	—	—	225
	$ 225	$ (91)	$ 3,080	$ —	$ 3,214

	December 31, 2018				
	Level 1	**Level 2**	**Level 3**	**Effect of Netting**	**Net Amounts Presented**
	(In thousands)				
Financial assets					

(liabilities):									
Commodity derivatives:									
Assets	$ —	$	3,225	$	10,964	$	(1,319)	$	12,870
Liabilities	—	(1,278)		(334)		1,319		(293)	
Total commodity derivatives	—	1,947		10,630		—		12,577	
Equity securities	194	—		—		—		194	
	$ 194	$	1,947	$	10,630	$	—	$	12,771

All our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post cash collateral with our counterparties and no collateral has been posted as of March 31, 2019.

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We used the following methods and assumptions 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 1 Fair Value Measurements

Equity Securities. We measure the fair values of our available for sale securities based on market quotes.

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 and three-way 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 table is a reconciliation of our level 3 fair value measurements:

	Net Derivatives Three Months Ended March 31,			
	2019		**2018**	
	(In thousands)			
Beginning of period	$	10,630	$	(206)
Total gains or losses (realized and unrealized):				
Included in earnings [1]	(5,434)		(3,919)	
Settlements	(2,116)		919	
End of period	$	3,080	$	(3,206)
Total losses for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	$	(7,550)	$	(3,000)

1.Commodity derivatives are reported in the Unaudited Condensed Consolidated Statements of Operations in gain (loss) on derivatives.

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

Commodity (1)	**Fair Value**		**Valuation Technique**	**Unobservable Input**	**Range**
	(In thousands)				
Oil three-way collars	$	3,096	Discounted cash flow	Forward commodity price curve	$0 - $7.93
Natural gas collars	$	(16)	Discounted cash flow	Forward commodity price curve	$0 - $0.13

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

Our valuation at March 31, 2019 reflected that the risk of non-performance was immaterial.

Fair Value of Other Financial Instruments

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

At March 31, 2019, the carrying values on the Unaudited Condensed Consolidated Balance Sheets for cash and cash equivalents (composed of bank and money market accounts - classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short-term nature.

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Based on the borrowing rates available to us for credit agreement debt with similar terms and maturities and considering the risk of our non-performance, long-term debt under the Unit and Superior credit agreements approximate their fair value and at March 31, 2019 we had $40.0 million of outstanding borrowings under the Unit and none under the Superior credit agreements. We had no borrowing under either the Unit or Superior Credit agreements at December 31, 2018. Borrowings under these agreements are classified as Level 2.

The carrying amounts of long-term debt associated with the Notes, net of unamortized discount and debt issuance costs, reported in the Unaudited Condensed Consolidated Balance Sheets as of March 31, 2019 and December 31, 2018 were $645.0 million and $644.5 million, respectively. We estimate the fair value of the Notes using quoted marked prices at March 31, 2019 and December 31, 2018 was $626.0 million and $600.5 million, respectively. The 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 7 – Asset Retirement Obligations.

NOTE 12 – 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 of 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 the 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 March 31, 2019, we had an average working interest of 87% 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, allows us to carry forward the historical lease classification; and the land easement expedient, which allows us to apply the guidance prospectively at adoption for land easements on existing agreements.We applied the short-term policy election, which allows us to exclude from recognition on the balance sheet leases with an initial term of 12 months or less. We considered quantitative

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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 our drilling segment lessor drilling rig contracts 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 Unaudited Condensed 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. Adoption of Topic 842 will not materially impact our Company's results of operations or cash flows.

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 three months of March 31, 2019:

	Amount	
	(In thousands)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases	$	577
Financing cash flows for finance leases	985	
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 Unaudited Condensed Consolidated Balance Sheet as of March 31, 2019:

	Classification on the Consolidated Balance Sheet	March 31, 2019	
		(In thousands)	
Assets			
Operating right of use assets	Right of use assets	$	4,551
Finance right of use assets	Property, plant, and equipment, net	18,886	
Total right of use assets		$	23,437
Liabilities			
Current liabilities:			
Operating lease liabilities	Current operating lease liabilities	$	2,369
Finance lease liabilities	Current portion of other long-term liabilities	4,041	
Non-current liabilities:			
Operating lease liabilities	Operating lease liabilities	1,952	
Finance lease liabilities	Other long-term liabilities	6,354	
Total lease liabilities		$	14,716

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The following table shows certain information related to the lease costs for our finance and operating leases for the three months ended March 31, 2019:

	Amount	
	(In thousands)	
Components of total lease cost:		
Amortization of finance leased assets	$	985
Interest on finance lease liabilities	111	
Operating lease cost	598	
Short-term lease cost (1)	9,974	
Variable lease cost	106	
Total lease cost	$	11,774

1.Short-term lease cost includes amounts capitalized related to our oil and natural gas segment of $5.7 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	2.5	6.18%
Finance leases	2.4	4.00%

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

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

	Amount	
	(In thousands)	
Ending April 1,		
2020	$	2,582
2021	1,409	
2022	550	
2023	12	

2024	12	
2025 and beyond	84	
Total future payments	4,649	
Less: Interest	328	
Present value of future minimum operating lease payments	4,321	
Less: Current portion	2,369	
Total long-term operating lease payments	$	1,952

As of March 31, 2019, we had additional leases that have not yet commenced of $1.7 million. These leases will commence in 2019 with lease terms of one to three years.

Finance Leases

In 2014, Superior 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 $4.0 million current portion of the finance lease obligations is included in current portion of other long-term liabilities and the non-current portion of $6.4 million is included in

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other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of March 31, 2019. These finance leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are $3.7 million and $0.5 million, respectively, at March 31, 2019. Annual payments, net of maintenance and interest, average $4.3 million annually through 2021. At the end of the term, Superior has the option to purchase the assets at 10% of their then fair market value.

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

	Amount	
Ending April 1,	**(In thousands)**	
2020	$	6,195
2021	7,841	
2022	579	
Total future payments	14,615	
Less payments related to:		
Maintenance	3,695	
Interest	525	
Present value of future minimum finance lease payments	10,395	
Less: Current portion	4,041	
Total long-term finance lease payments	$	6,354

NOTE 13 – COMMITMENTS AND CONTINGENCIES

The employee oil and gas limited partnerships require, on the election of a limited partner, that we repurchase the limited partner’s interest at amounts to be determined by appraisal. In any one year, these repurchases are limited to 20% of the units outstanding. We had no repurchases in the first three months of 2019 or 2018.

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

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

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. If we elected not to drill or spend any money in the designated area over the three year period, the maximum amount we could forgo from distributions would be $87.0 million. Total spent towards the $150.0 million as of March 31, 2019 was $8.3 million.

For the next 12 months, we have committed to purchase approximately $4.0 million of new drilling rig components.

NOTE 14 – 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

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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 during the quarter ended March 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:

	March 31, 2019	**December 31, 2018**
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 3,128	$ 5,841
Accounts receivable	23,331	33,207
Prepaid expenses and other	2,446	1,049
Total current assets	28,905	40,097
Property and equipment:		
Gas gathering and processing equipment	781,970	767,388
Transportation equipment	3,264	3,086
	785,234	770,474
Less accumulated depreciation,	376,006	364,740

depletion, amortization, and impairment				
Net property and equipment	409,228		405,734	
Right of use asset	2,779		—	
Other assets	16,048		17,551	
Total assets	$	456,960	$	463,382
Current liabilities:				
Accounts payable	$	24,246	$	32,214
Accrued liabilities	3,153		3,688	
Current operating lease liability	1,702		—	
Current portion of other long-term liabilities	6,923		6,875	
Total current liabilities	36,024		42,777	
Long-term debt less debt issuance costs	—		—	
Operating lease liability	937		—	
Other long-term liabilities	13,048		14,687	
Total liabilities	$	50,009	$	57,464

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NOTE 15 – EQUITY

Accumulated Other Comprehensive Income (Loss)

Components of accumulated other comprehensive income (loss) were as follows for the three months ended March 31:

	2019		2018		
	(In thousands)				
Unrealized appreciation (loss) on securities, before tax	$	31	$	(234)	
Tax benefit (expense)	(7)		58		(1)
Unrealized appreciation (loss) on securities, net of tax	$	24	$	(176)	

1.Due to the implementation of ASU 2018-02, the tax rate changed from 37.75% to 24.5%.

Changes in accumulated other comprehensive income by component, net of tax, for the three months ended March 31 are as follows:

	Net Gains on Equity Securities				
	2019		2018		
	(In thousands)				
Balance at December 31:	$	(481)	$	63	
Adjustment due to ASU 2018-02	—		13		(1)
Balance at January 1:	(481)		76		
Unrealized appreciation (loss) before reclassifications	24		(176)		(1)
Amounts reclassified from accumulated other comprehensive income	—		—		
Net current-period other	24		(176)		

comprehensive income (loss)				
Balance at March 31:	$	(457)	$	(100)

1.Due to the implementation of ASU 2018-02, the tax rate changed from 37.75% to 24.5%.

NOTE 16 – INDUSTRY SEGMENT INFORMATION

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

•Oil and natural gas,
•Contract drilling, and
•Mid-stream

Our oil and natural gas segment is engaged in the acquisition, development, 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. We have no oil and natural gas production outside the United States.

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

	Three Months Ended March 31, 2019					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: (1)						
Oil and natural gas	$ 86,095	$ —	$ —	$ —	$ —	$ 86,095
Contract drilling	—	58,199	—	—	(7,044)	51,155
Gas gathering and processing	—	—	70,509	—	(18,068)	52,441
Total revenues	86,095	58,199	70,509	—	(25,112)	189,691
Expenses:						
Operating costs:						
Oil and natural gas	34,008	—	—	—	(1,294)	32,714
Contract drilling	—	37,385	—	—	(5,984)	31,401
Gas gathering and processing	—	—	56,129	—	(16,774)	39,355
Total operating costs	34,008	37,385	56,129	—	(24,052)	103,470
Depreciation, depletion, and amortization	35,767	12,699	11,726	1,934	—	62,126
Total expenses	69,775	50,084	67,855	1,934	(24,052)	165,596
General and administrative	—	—	—	9,741	—	9,741
(Gain) loss on disposition of assets	(79)	1,746	(42)	(10)	—	1,615
Income (loss) from operations	16,399	6,369	2,696	(11,665)	(1,060)	12,739
Loss on derivatives	—	—	—	(6,932)	—	(6,932)
Interest, net	—	—	(336)	(8,202)	—	(8,538)
Other	—	—	—	5	—	5
Income (loss)	$ 16,399	$ 6,369	$ 2,360	$ (26,794)	$ (1,060)	$ (2,726)

before
income
taxes

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.

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	Three Months Ended March 31, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: (1)						
Oil and natural gas	$ 103,099	$ —	$ —	$ —	$ —	$ 103,099
Contract drilling	—	50,710	—	—	(4,721)	45,989
Gas gathering and processing	—	—	74,650	—	(18,606)	56,044
Total revenues	103,099	50,710	74,650	—	(23,327)	205,132
Expenses:						
Operating costs:						
Oil and natural gas	37,152	—	—	—	(1,190)	35,962
Contract drilling	—	35,954	—	—	(4,287)	31,667
Gas gathering and processing	—	—	59,020	—	(17,416)	41,604
Total operating costs	37,152	35,954	59,020	—	(22,893)	109,233
Depreciation, depletion, and amortization	30,783	13,312	11,053	1,918	—	57,066
Total expenses	67,935	49,266	70,073	1,918	(22,893)	166,299
General and administrative expense	—	—	—	10,762	—	10,762
Gain on disposition of assets	(71)	(26)	(34)	(30)	—	(161)
Income (loss) from operations	35,235	1,470	4,611	(12,650)	(434)	28,232
Loss on derivatives	—	—	—	(6,762)	—	(6,762)
Interest, net	—	—	(149)	(9,855)	—	(10,004)
Other	—	—	—	6	—	6
Income (loss) before	$ 35,235	$ 1,470	$ 4,462	$ (29,261)	$ (434)	$ 11,472

income
taxes

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.

NOTE 17 – 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 unaudited 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 unaudited 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.

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Condensed Consolidating Balance Sheets (Unaudited)

	March 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ 507	$ 256	$ 3,128	$ —	$ 3,891
Accounts receivable, net of allowance for doubtful accounts of $2,531 (Guarantor of $1,326 and Parent of $1,205)	1,879	75,400	23,871	(7,275)	93,875
Materials and supplies	—	495	—	—	495
Current derivative asset	3,464	—	—	—	3,464
Income taxes receivable	243	1,811	—	—	2,054
Assets held for sale	—	19,728	—	—	19,728
Prepaid expenses and other	2,190	2,868	2,446	—	7,504
Total current assets	8,283	100,558	29,445	(7,275)	131,011
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	6,104,092	—	—	6,104,092
Unproved properties not being amortized	—	339,957	—	—	339,957
Drilling equipment	—	1,279,735	—	—	1,279,735
Gas gathering and processing equipment	—	—	781,970	—	781,970
Saltwater disposal systems	—	69,010	—	—	69,010
Corporate land and	—	59,080	—	—	59,080

building					
Transportation equipment	9,731	17,332	3,264	—	30,327
Other	28,669	28,955	—	—	57,624
	38,400	7,898,161	785,234	—	8,721,795
Less accumulated depreciation, depletion, amortization, and impairment	29,057	5,820,157	376,006	—	6,225,220
Net property and equipment	9,343	2,078,004	409,228	—	2,496,575
Intercompany receivable	993,100	—	—	(993,100)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,171,779	1,500	—	(1,171,779)	1,500
Right of use asset	10	1,762	2,779	—	4,551
Other assets	8,758	7,929	16,048	—	32,735
Total assets	$ 2,191,273	$ 2,252,561	$ 457,500	$ (2,172,154)	$ 2,729,180

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	March 31, 2019				
	Parent	**Combined Guarantor Subsidiaries**	**Combined Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total Consolidated**
	(In thousands)				
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 10,199	$ 104,928	$ 24,176	$ (6,404)	$ 132,899
Accrued liabilities	29,654	15,342	3,555	(467)	48,084
Current operating lease liability	9	658	1,702	—	2,369
Current portion of other long-term liabilities	781	6,606	6,923	—	14,310
Total current liabilities	40,643	127,534	36,356	(6,871)	197,662
Intercompany debt	—	993,182	(82)	(993,100)	—
Long-term debt less debt issuance costs	685,031	—	—	—	685,031
Non-current derivative liability	475	—	—	—	475
Operating lease liability	—	1,015	937	—	1,952
Other long-term liabilities	14,356	76,831	13,048	(403)	103,832
Deferred income taxes	57,319	87,050	—	—	144,369
Shareholders' equity:					
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—	—	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 55,467,987 shares issued	10,578	—	—	—	10,578
Capital in excess of par value	633,361	45,921	197,042	(242,963)	633,361
Contributions from Unit	—	—	1,078	(1,078)	—
Accumulated other comprehensive loss	—	(457)	—	—	(457)
Retained earnings	749,510	921,485	6,254	(927,739)	749,510
Total shareholders' equity attributable to Unit Corporation	1,393,449	966,949	204,374	(1,171,780)	1,392,992
Non-controlling interests in consolidated subsidiaries	—	—	202,867	—	202,867

Total shareholders' equity	1,393,449	966,949	407,241	(1,171,780)	1,595,859
Total liabilities and shareholders' equity	$ 2,191,273	$ 2,252,561	$ 457,500	$ (2,172,154)	$ 2,729,180

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	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)	2,539	94,526	36,676	(14,344)	119,397
Materials and supplies	—	473	—	—	473
Current derivative asset	12,870	—	—	—	12,870
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	18,048	123,089	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	950,916	—	—	(950,916)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,160,444	1,500	—	(1,160,444)	1,500
Other assets	8,225	5,293	17,552	—	31,070
Total assets	$ 2,147,986	$ 2,208,920	$ 466,851	$ (2,125,704)	$ 2,698,053

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	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	$ 8,697	$ 122,610	$ 32,214	$ (13,576)	$ 149,945
Accrued liabilities	28,230	16,409	5,493	(468)	49,664
Current portion of other long-term liabilities	812	6,563	6,875	—	14,250
Total current liabilities	37,739	145,582	44,582	(14,044)	213,859
Intercompany debt	—	948,707	2,209	(950,916)	—
Long-term debt less debt issuance costs	644,475	—	—	—	644,475
Non-current derivative liability	293	—	—	—	293
Other long-term liabilities	13,134	73,713	14,687	(300)	101,234
Deferred income taxes	60,983	83,765	—	—	144,748
Shareholders' equity:					
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—	—	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 54,055,600 shares issued	10,414	—	—	—	10,414
Capital in excess of par value	628,108	45,921	197,042	(242,963)	628,108
Contributions from Unit	—	—	792	(792)	—
Accumulated other comprehensive loss	—	(481)	—	—	(481)
Retained earnings	752,840	911,713	4,976	(916,689)	752,840
Total shareholders' equity attributable to Unit Corporation	1,391,362	957,153	202,810	(1,160,444)	1,390,881
Non-controlling interests in consolidated subsidiaries	—	—	202,563	—	202,563
Total shareholders' equity	1,391,362	957,153	405,373	(1,160,444)	1,593,444

Total liabilities and shareholders' equity	$	2,147,986	$	2,208,920	$	466,851	$	(2,125,704)	$	2,698,053

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Condensed Consolidating Statements of Operations (Unaudited)

	Three Months Ended March 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 144,294	$ 70,509	$ (25,112)	$ 189,691
Expenses:					
Operating costs	—	71,393	56,129	(24,052)	103,470
Depreciation, depletion, and amortization	1,934	48,466	11,726	—	62,126
General and administrative	—	9,741	—	—	9,741
(Gain) loss on disposition of assets	(10)	1,667	(42)	—	1,615
Total operating costs	1,924	131,267	67,813	(24,052)	176,952
Income (loss) from operations	(1,924)	13,027	2,696	(1,060)	12,739
Interest, net	(8,202)	—	(336)	—	(8,538)
Loss on derivatives	(6,932)	—	—	—	(6,932)
Other, net	5	—	—	—	5
Income (loss) before income taxes	(17,053)	13,027	2,360	(1,060)	(2,726)
Income tax expense (benefit)	(3,699)	3,255	—	—	(444)
Equity in net earnings from investment in subsidiaries, net of taxes	9,850	—	—	(9,850)	—
Net income (loss)	(3,504)	9,772	2,360	(10,910)	(2,282)
Less: net income attributable to non-controlling interest	—	—	1,222	—	1,222
Net income (loss) attributable to Unit Corporation	$ (3,504)	$ 9,772	$ 1,138	$ (10,910)	$ (3,504)

	Three Months Ended March 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$ —	$ 153,809	$ 74,650	$ (23,327)	$ 205,132
Expenses:					
Operating costs	—	73,106	59,020	(22,893)	109,233
Depreciation, depletion, and amortization	1,918	44,095	11,053	—	57,066

General and administrative	—	8,229	2,533	—	10,762
Gain on disposition of assets	(30)	(97)	(34)	—	(161)
Total operating costs	1,888	125,333	72,572	(22,893)	176,900
Income (loss) from operations	(1,888)	28,476	2,078	(434)	28,232
Interest, net	(9,855)	—	(149)	—	(10,004)
Loss on derivatives	(6,762)	—	—	—	(6,762)
Other, net	6	1	(1)	—	6
Income (loss) before income taxes	(18,499)	28,477	1,928	(434)	11,472
Income tax expense (benefit)	(4,639)	7,648	598	—	3,607
Equity in net earnings from investment in subsidiaries, net of taxes	21,725	—	—	(21,725)	—
Net income attributable to Unit Corporation	7,865	20,829	1,330	(22,159)	7,865

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Condensed Consolidating Statements of Comprehensive Income (Loss) (Unaudited)

	Three Months Ended March 31, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income (loss)	$ (3,504)	$ 9,772	$ 2,360	$ (10,910)	$ (2,282)
Other comprehensive income (loss), net of taxes:					
Unrealized gain on securities, net of tax $7	—	24	—	—	24
Comprehensive income (loss)	(3,504)	9,796	2,360	(10,910)	(2,258)
Less: Comprehensive income attributable to non-controlling interests	—	—	1,222	—	1,222
Comprehensive income (loss) attributable to Unit Corporation	$ (3,504)	$ 9,796	$ 1,138	$ (10,910)	$ (3,480)

	Three Months Ended March 31, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income	$ 7,865	$ 20,829	$ 1,330	$ (22,159)	$ 7,865
Other comprehensive income, net of taxes:					
Unrealized gain on securities, net of tax of ($58)	—	(176)	—	—	(176)
Comprehensive income	7,865	20,653	1,330	(22,159)	7,689
Less: Comprehensive income attributable to non-controlling interests	—	—	—	—	—
Comprehensive income attributable to Unit Corporation	$ 7,865	$ 20,653	$ 1,330	$ (22,159)	$ 7,689

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Condensed Consolidating Statements of Cash Flows (Unaudited)

	Three Months Ended March 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	$ (562)	$ 64,168	$ 13,506	$ (34)	$ 77,078
INVESTING ACTIVITIES:					
Capital expenditures	(321)	(110,089)	(12,097)	—	(122,507)
Producing properties and other acquisitions	—	(1,580)	—	—	(1,580)
Proceeds from disposition of assets	10	3,142	38	—	3,190
Net cash used in investing activities	(311)	(108,527)	(12,059)	—	(120,897)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	106,900	—	2,900	—	109,800
Payments under credit agreement	(66,900)	—	(2,900)	—	(69,800)
Intercompany borrowings (advances), net	(43,103)	44,407	(1,338)	34	—
Payments on finance leases	—	—	(985)	—	(985)
Distributions to non-controlling interest	919	—	(1,837)	—	(918)
Book overdrafts	3,161	—	—	—	3,161
Net cash provided by financing activities	977	44,407	(4,160)	34	41,258
Net increase (decrease) in cash and cash equivalents	104	48	(2,713)	—	(2,561)
Cash and cash equivalents, beginning of period	403	208	5,841	—	6,452
Cash and cash equivalents, end of period	$ 507	$ 256	$ 3,128	$ —	$ 3,891

Three Months Ended March 31, 2018

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by operating activities	$ (5,452)	$ 74,277	$ 14,743	$ —	$ 83,568
INVESTING ACTIVITIES:					
Capital expenditures	(56)	(79,855)	(10,338)	—	(90,249)
Producing properties and other acquisitions	—	—	—	—	—
Proceeds from disposition of assets	30	22,028	26	—	22,084
Net cash used in investing activities	(26)	(57,827)	(10,312)	—	(68,165)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	67,400	—	—	—	67,400
Payments under credit agreement	(97,700)	—	—	—	(97,700)
Intercompany borrowings (advances), net	19,880	(16,395)	(3,485)	—	—
Payments on finance leases	—	—	(946)	—	(946)
Book overdrafts	15,894	—	—	—	15,894
Net cash provided by (used in) financing activities	5,474	(16,395)	(4,431)	—	(15,352)
Net increase (decrease) in cash and cash equivalents	(4)	55	—	—	51
Cash and cash equivalents, beginning of period	510	191	—	—	701
Cash and cash equivalents, end of period	$ 506	$ 246	$ —	$ —	$ 752

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis (MD&A) provides you with an understanding of our operating results and financial condition by focusing on changes in certain key measures from year to year or period to period. MD&A is organized into these sections:

- General;
- Business Outlook;
- Executive Summary;
- Financial Condition and Liquidity;
- New Accounting Pronouncements; and
- Results of Operations.

Please read the information in our most recent Annual Report on Form 10-K in conjunction with your review of the information below and our unaudited condensed consolidated financial statements and related notes.

Unless otherwise indicated or required by the content, when used in this report 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 refers to Superior Pipeline Company, L.L.C. of which we own 50%.

General

We operate, manage, and analyze the results of our 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 oil and natural gas segment.
- *Mid-Stream* – carried out by Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account. We own 50% of this subsidiary.

In addition to the companies identified above, our corporate headquarters is owned by our wholly owned subsidiary "8200 Unit Drive, L.L.C.".

Business Outlook

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

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Executive Summary

Oil and Natural Gas

First quarter 2019 production from our oil and natural gas segment was 4,123,000 barrels of oil equivalent (Boe), a decrease of 5% from the fourth quarter of 2018 and a decrease of 1% from the first quarter of 2018, respectively. The decreases for both comparative periods were primarily from a 14-day plant shut-down (12-days of which were in the first quarter of 2019) that resulted in a loss of slightly over 165 MBoe for the quarter.

First quarter 2019 oil and natural gas revenues decreased 19% from the fourth quarter of 2018 and decreased (16)% from the first quarter of 2018. The decreases were primarily from a decrease in commodity prices as well as volumes.

Our oil prices for the first quarter of 2019 increased 4% over the fourth quarter of 2018 and increased 2% over the first quarter of 2018. Our NGLs prices decreased 18% from the fourth quarter of 2018 and decreased 24% from the first quarter of 2018. Our natural gas prices decreased 9% from the fourth quarter of 2018 and decreased 4% from the first quarter of 2018.

Operating cost per Boe produced for the first quarter of 2019 increased 10% over the fourth quarter of 2018 and decreased 8% from the first quarter of 2018. The increase over the fourth quarter of 2018 was primarily due to increased general and administrative expense and saltwater disposal expense partially offset by lower equivalent production and lower lease operating expenses. The decrease from the first quarter of 2018 was primarily due to lower lease operating expenses and lower equivalent production partially offset by higher general and administrative expenses.

At March 31, 2019, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'19 – Oct'19	Natural gas – swap	60,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Nov'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Apr'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Apr'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Apr'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Apr'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Apr'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

For the three months ended March 31, 2019, we completed drilling 18 gross wells (5.57 net wells). For all of 2019, we anticipate participating in the drilling of approximately 90 to 100 gross wells. Excluding a reduction in ARO liability and any possible acquisitions, our estimated 2019 capital expenditures for this segment ranges from approximately $315.0 million to $371.0 million. Our current 2019 production guidance is approximately 17.4 to 17.9 MMBoe, an increase of 2-5% over 2018, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated in the first quarter of 2019 was 31.4 compared to 33.1 and 31.7 in the fourth quarter of 2018 and the first quarter of 2018, respectively. As of March 31, 2019, 32 of our drilling rigs were operating.

Revenue for the first quarter of 2019 decreased 3% from the fourth quarter of 2018 and increased 11% over the first quarter of 2018. The decrease from the fourth quarter of 2018 was primarily due to fewer drilling rigs operating and decreased utilization from outside operators partially offset by higher dayrates and $4.8 million received for early termination fees. The increase over the first quarter of 2018 was primarily due to higher dayrates and $4.8 million in early termination fees partially offset by fewer drilling rigs operating.

Dayrates for the first quarter of 2019 averaged $18,339, a 2% increase over the fourth quarter of 2018 and a 8% increase over the first quarter of 2018. The increase over the fourth quarter of 2018 was primarily due to general increases with the improving market and the addition of two BOSS drilling rigs. The increase over the first quarter of 2018 was due to a labor increase passed through to contracted rigs rates and improving market dayrates.

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Operating costs for the first quarter of 2019 decreased 12% from the fourth quarter of 2018 and decreased 1% from the first quarter of 2018. The decreases were both primarily due to less drilling rigs operating.

Currently, we have 15 term drilling contracts with original terms ranging from six months to three years. Five are up for renewal in the second quarter of 2019, two in the third quarter of 2019, three in the fourth quarter of 2019, two in 2020, and three after 2020. 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 early and pay an early termination penalty for the remaining term of the contract. We recorded $4.8 million in early termination fees in the first quarter of 2019. We had no early termination fees for 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.

Mid-Stream

First quarter 2019 liquids sold per day decreased 7% from the fourth quarter of 2018 and increased 13% over the first quarter of 2018, respectively. The decrease from the fourth quarter of 2018 was due to lower processed volumes and lower recoveries due to higher ethane rejection partially offset by higher processed volume on the Cashion system. The increase over the first quarter of 2018 was primarily due to increased volume available to process at our processing facilities due to additional well connections along with operating in higher recovery mode. For the first quarter of 2019, gas processed per day increased 1% over the fourth quarter of 2018 and increased 7% over the first quarter of 2018. The increase over the fourth quarter of 2018 was primarily due to higher volumes from new wells connected mainly to our Cashion processing facility. The increase over the first quarter of 2018 was due to new wells connected to several of our processing facilities. For the first quarter of 2019, gas gathered per day increased 14% and 21% over the fourth quarter of 2018 and the first quarter of 2018, respectively. These increases are both due to connecting additional wells to our gathering and processing facilities primarily in Pennsylvania and Oklahoma.

NGLs prices in the first quarter of 2019 decreased 14% from the prices received in the fourth quarter of 2018 and decreased 27% from the prices received in the first 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 the price of NGLs.

Total operating cost for our mid-stream segment for the first quarter of 2019 decreased 9% from the fourth quarter of 2018 and decreased 5% from the first quarter of 2018. The decrease from the fourth quarter of 2018 was primarily due to lower gas purchase prices. The decrease over the first quarter of 2018 was primarily due to lower gas purchase prices.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for March of 2019 was 230.9 MMcf per day while the average gathered volume for the first quarter of 2019 was approximately 196.9 MMcf per day. In the first quarter of 2019, we added seven new wells beginning in late January through the first part of February which accounted for the significant increase in gathered volume. These wells were all long lateral wells that have now been placed in production and are continuing to produce better than expected results. The Kissick compressor station facilities have been upgraded in order to handle the increased volume from these wells.

At the Cashion processing facility in central Oklahoma, total throughput volume for the first quarter of 2019 averaged approximately 53.9 MMcf per day and total production of natural gas liquids increased to 263,980 gallons per day. As we continue to connect new wells to this system and with the increase in volume, this facility is operating at full processing capacity and we are completing the addition of a new 60 MMcf per day processing plant for this system. We have relocated a 60 MMcf per day processing plant from our Bellmon facility to the Cashion area. This expander plant has been installed at the Reeding site on the Cashion system. Most of the construction for the installation of this processing plant has been completed and the plant is expected to be operational in the first part of the second quarter of 2019. The addition of this new processing facility will increase our total processing capacity on the Cashion system to approximately 105 MMcf per day. We connected seven new wells to this system during the first quarter of 2019 from several third party producers who continue to be active in the area.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the first quarter of 2019 was 73.4 MMcf per day and total production of natural gas liquids was approximately 250,629 gallons per day during this

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same period. During the first quarter, we did not connect any new wells to this system but we are currently working on connections for three new wells in the Buffalo Wallow area. These new Unit Petroleum wells are expected to be connected and flowing in the second quarter of 2019.

At the Minco processing facility in central Oklahoma, total throughput volume for the first quarter of 2019 was approximately 8.7 MMcf per day. During the first quarter of 2019 we completed construction of a new well connection for a third party producer. This new well connection allows us to connect a new well for this producer but also allows us the ability to connect other producers in the area. The current processing capacity of the Minco facility is approximately 12 MMcf per day.

Our estimated 2019 capital expenditures for this segment rang from approximately $35.0 million to $42.0 million.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreements. Our cash flow is based primarily on:

•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.

We believe we will have enough cash flow and liquidity to meet our obligations and remain in compliance with our debt covenants for the next 12 months. 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 will be affected by financial, business, economic, regulatory, and other factors. For example, if we experience lower oil, natural gas, and NGLs prices since the last borrowing base determination under the Unit credit agreement, it could reduce the borrowing base and therefore reduce or limit our ability to incur indebtedness. We monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues, and work, where possible, with our lenders to address those issues ahead of time.

	Three Months Ended March 31, 2019	2018	% Change
	(In thousands except percentages)		
Net cash provided by operating activities	$ 77,078	$ 83,568	(8)%
Net cash used in investing activities	(120,897)	(68,165)	77%
Net cash provided by (used in) financing activities	41,258	(15,352)	NM
	$ (2,561)	$ 51	

Net increase
(decrease) in
cash and
cash
equivalents

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

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, NGLs, and natural gas production, the quantity of oil, NGLs, and natural gas we produce, settlements of derivative contracts, and third-party demand for our drilling rigs and mid-stream services and the rates we obtain for those services. Our cash flows from operating activities are also affected by changes in working capital.

Net cash provided by operating activities in the first three months of 2019 decreased by $6.5 million as compared to the first three months of 2018. The decrease was primarily due to decreased operating profit in the oil and gas segment and a decrease in changes in operating assets and liabilities related to the timing of cash receipts and disbursements partially offset by increases in cash for derivatives settled.

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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 increased by $52.7 million for the first three months of 2019 compared to the first three months of 2018. The change was due primarily to an increase in capital expenditures for development drilling and construction of BOSS drilling rigs partially offset by a reduction in cash proceeds on the sale 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 $56.6 million for the first three months of 2019 compared to the first three months of 2018. The increase was primarily due to an increase in the net borrowings under our credit agreements partially offset by a decrease in book overdrafts.

At March 31, 2019, we had unrestricted cash and cash equivalents totaling $3.9 million and had borrowed $40.0 million of the $425.0 million and none of the $200.0 million we had elected to have available under the Unit and Superior credit agreements, respectively. The credit agreements are used primarily for working capital and capital expenditures.

Below, we summarize certain financial information as of March 31, 2019 and 2018 and for the three months ended March 31, 2019 and 2018:

	March 31,				% Change
	2019		2018		
	(In thousands except percentages)				
Working capital	$	(66,651)	$	(103,566)	36%
Long-term debt less debt issuance costs	$	685,031	$	790,522	(13)%
Shareholders' equity attributable to Unit Corporation	$	1,392,992	$	1,357,300	3%
Net income (loss) attributable to Unit Corporation	$	(3,504)	$	7,865	(145)%

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 $66.7 million and negative working capital of $103.6 million as of March 31, 2019 and 2018, respectively. The increase in working capital is primarily due to increased assets held for sale in our contract drilling segment and changes in our current derivative position. The Unit and Superior credit agreements are used primarily for working capital and capital expenditures. At March 31, 2019, we had borrowed $40.0 million of the $425.0 million and none of the $200.0 million available under the Unit or Superior credit agreements, respectively. The effect of our derivative contracts increased working capital by $3.5 million as of March 31, 2019 and decreased working capital by $11.6 million as of March 31, 2018.

This table summarizes certain operating information:

	Three Months Ended March 31, 2019	2018	% Change
Oil and Natural Gas:			
Oil production (MBbls)	688	736	(7)%
NGLs production (MBbls)	1,207	1,195	1%
Natural gas production (MMcf)	13,371	13,499	(1)%
Equivalent barrels (MBoe)	4,123	4,181	(1)%
Average oil price per barrel received	$ 56.29	$ 55.10	2%
Average oil price per barrel received excluding derivatives	$ 53.14	$ 61.21	(13)%
Average NGLs price per barrel received	$ 16.06	$ 21.08	(24)%
Average NGLs price per barrel received excluding derivatives	$ 16.06	$ 21.08	(24)%
Average natural gas price per Mcf received	$ 2.52	$ 2.62	(4)%
Average natural gas price per Mcf received excluding derivatives	$ 2.49	$ 2.44	2%
Net impact of revenue recognition (ASC 606) per Boe (1)	$ (1.36)	$ (0.76)	(79)%
Average realized price per Boe received	$ 20.92	$ 23.42	(11)%
Average realized price per Boe received excluding derivatives	$ 20.28	$ 23.92	(15)%
Contract Drilling:			

Average number of our drilling rigs in use during the period	31.4	31.7	(1)%
Total number of drilling rigs owned at the end of the period	57	95	(40)%
Average dayrate	$ 18,339	$ 17,038	8%
Mid-Stream:			
Gas gathered—Mcf/day	449,916	372,862	21%
Gas processed—Mcf/day	161,748	151,039	7%
Gas liquids sold—gallons/day	650,614	577,560	13%
Number of natural gas gathering systems	22	22	—%
Number of processing plants	12	13	(8)%

1.Pursuant to accounting guidance on revenue recognition (ASC 606); gathering, processing, and transportation costs are reflected as a deduction from revenue instead of as an expense when we arrange for another company to provide the good or service.

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, and by worldwide oil price levels. Global oil market developments primarily influence domestic oil prices. These factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first three months of 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 $431,000 per month ($5.2 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of derivatives, during the first three months of 2019 was $2.52 compared to $2.62 for the first three months of 2018. Based on our first three months of 2019 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $220,000 per month ($2.6 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 $387,000 per month ($4.6 million annualized) change in our pre-tax operating cash flow. In the first three months of 2019, our average oil price per barrel received, including the effect of derivatives, was $56.29 compared with an average oil price, including the effect of derivatives, of $55.10 in the first three months of 2018 and our first three months of 2019 average NGLs price per barrel received, including the effect of derivatives was $16.06 compared with an average NGLs price per barrel of $21.08 in the first three months of 2018.

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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 March 31, 2019, the 12-month average unescalated prices were $63.00 per barrel of oil, $35.52 per barrel of NGLs, and $3.07 per Mcf of natural gas, and then are adjusted for price differentials. We did not take a write down in the first three months of 2019.

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 March 31, 2019, and only adjust the 12-month average price to an estimated second quarter ending average (holding April 2019 prices constant for the remaining two months of the second quarter of 2019), our forward looking expectation is that we will not recognize an impairment in the second quarter of 2019. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for a

Our natural gas production is sold to intrastate and interstate pipelines and to independent marketing firms and gatherers under contracts with terms 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 are 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.

Most of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The continuous fluctuations in commodity prices for oil and natural gas changes the demand for drilling rigs. These factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. The future demand for and the availability of drilling rigs to meet that demand will affect our future dayrates. For the first three months of 2019, our average dayrate was $18,339 per day compared to $17,038 per day for the first three months of 2018. The average number of our drilling rigs used in the first three months of 2019 was 31.4 drilling rigs compared with 31.7 drilling rigs in the first three months of 2018. Based on the average utilization of our drilling rigs during the first three months of 2019, a $100 per day change in dayrates has a $3,140 per day ($1.1 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 to be associated with acquiring an ownership interest in the property. In those cases, revenues and expenses for those services are eliminated in our income statements, 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. We eliminated revenue of $7.0 million and $4.7 million for the first three months of 2019 and 2018, respectively, from our contract drilling segment and eliminated the associated operating expense of $6.0 million and $4.3 million during the first three months of 2019 and 2018, respectively, yielding $1.1 million and $0.4 million during the first three months of 2019 and 2018, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Mid-Stream Operations

Our mid-stream segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 12 processing plants, 22 gathering systems, and approximately 1,490 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. Besides serving third parties, this segment also enhances our ability to gather and market our own natural gas and NGLs and serving as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first three months of 2019 and 2018, our mid-stream operations purchased $16.3 million and $16.9 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $1.8 million and $1.7 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 unaudited condensed consolidated financial statements.

This segment gathered an average of 449,916 Mcf per day in the first three months of 2019 compared to 372,862 Mcf per day in the first three months of 2018. It processed an average of 161,748 Mcf per day in the first three months of 2019 compared to 151,039 Mcf per day in the first three months of 2018. The NGLs sold was 650,614 gallons per day in the first

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three months of 2019 compared to 577,560 gallons per day in the first three months of 2018. Gas gathered volumes per day in the first three months of 2019 increased 21% compared to the first three months of 2018 primarily due to connecting additional wells to our Pennsylvania and Oklahoma facilities. Gas processed volumes for the first three months of 2019 increased 7% over the first three months of 2018 due to connecting new wells to several of our processing facilities. NGLs sold increased 13% over the comparative period due to increased volume available to process at our processing facilities from additional well connections along with operating in higher recovery mode.

Our Credit Agreements and Senior Subordinated Notes

Unit Credit Agreement. On October 18, 2018, we amended our Senior Credit Agreement (Unit credit agreement) which is scheduled to mature on October 18, 2023. 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. Our elected commitment amount is $425.0 million. Our borrowing base is $425.0 million. We are currently 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 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.

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, under which we granted 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 current 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 on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime 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.

At our election, any part of the outstanding debt under the Unit credit agreement can be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the LIBOR base for the term plus 1.50% to 2.50% depending on the level of debt as a percentage of the borrowing base and 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 but in no event 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 March 31, 2019, we had $40.0 million outstanding under the Unit credit agreement.

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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 Unit credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

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

Superior Credit Agreement. On May 10, 2018, Superior, a limited liability company equally owned between the Company 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 currently 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 March 31, 2019, Superior was in compliance with the Superior credit agreement 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. As of March 31, 2019, we had no outstanding borrowings under the Superior credit agreement.

On June 27, 2018, Superior and the lenders amended the Superior credit agreement to revise certain definitions in the agreement.

Superior's credit agreement is not guaranteed by Unit.

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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) outstanding. Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes mature on May 15, 2021. In issuing the Notes, we incurred fees of $14.7 million 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 of and providing for issuing the Notes. The Guarantors are most of our direct and indirect subsidiaries, but excluding Superior. 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, occasionally, 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 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 of the Notes as of March 31, 2019.

We may from time to time seek to retire or purchase our outstanding Note debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Capital Requirements

Oil and Natural Gas Segment Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Our decisions to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances which provide us with flexibility in deciding when and if to incur these costs. We completed drilling 18 gross wells (5.57 net wells) in the first three months of 2019 compared to 15 gross wells (5.40 net wells) in the first three months of 2018.

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Capital expenditures for oil and gas properties on the full cost method for the first three months of 2019 by this segment, excluding $1.6 million for acquisitions and a $4.7 million increase in the ARO liability, totaled $90.1 million. Capital expenditures for the first three months of 2018, excluding less than $0.1 million for acquisitions and a $6.3 million reduction in the ARO liability, totaled $86.6 million.

We anticipate participating in drilling approximately 90 to 100 gross wells in 2019 and our total estimated capital expenditures (excluding a reduction in ARO liability and any possible acquisitions) for this segment range from approximately $271.0 million to $315.0 million. Whether we can drill the full number of wells planned depends on several factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. During the first quarter of 2018, we were awarded a term contract to build our 11th BOSS drilling rig. Construction has been completed and the drilling rig was placed into service in the second quarter.

During the first quarter of 2019, we completed construction and placed into service our 12th and 13th BOSS drilling rigs.

Our estimated 2019 capital expenditures for this segment range from approximately $30.0 million to $65.0 million. At March 31, 2019, we had commitments to purchase approximately $4.0 million for drilling equipment over the next year. We have spent $17.0 million r capital expenditures during the first three months of 2019, compared to $8.9 million for capital expenditures during the first three months of 2018.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for March of 2019 was 230.9 MMcf per day while the average gathered volume for the first quarter of 2019 was approximately 196.9 MMcf per day. In the first quarter of 2019, we added seven new wells beginning in late January through the first part of February which accounted for the significant increase in gathered volume. These wells were all long lateral wells that have now been placed in production and are continuing to produce better than expected results. The Kissick compressor station facilities have been upgraded in order to handle the increased volume from these wells.

At the Cashion processing facility in central Oklahoma, total throughput volume for the first quarter of 2019 averaged approximately 53.9 MMcf per day and total production of natural gas liquids increased to 263,980 gallons per day. As we continue to connect new wells to this system and with the increase in volume, this facility is operating at full processing capacity and we are completing the addition of a new 60 MMcf per day processing plant for this system. We have relocated a 60 MMcf per day processing plant from our Bellmon facility to the Cashion area. This expander plant has been installed at the Reeding site on the Cashion system. Most of the construction for the installation of this processing plant has been completed and the plant is expected to be operational in the second quarter of 2019. The addition of this new processing facility will increase our total processing capacity on the Cashion system to approximately 105 MMcf per day. We connected seven new wells to this system during the first quarter of 2019 from several third party producers who continue to be active in the area.

At the Hemphill processing facility located in the Texas panhandle, average total throughput volume for the first quarter of 2019 was 73.4 MMcf per day and total production of natural gas liquids was approximately 250,629 gallons per day during this same period. During the first quarter, we did not connect any new wells to this system but we are currently working on connections for three new wells in the Buffalo Wallow area. These new Unit Petroleum wells are expected to be connected and flowing in the second quarter of 2019.

At the Minco processing facility in central Oklahoma, total throughput volume for the first quarter of 2019 was approximately 8.7 MMcf per day. During the first quarter of 2019 we completed construction of a new well connection for a third party producer. This new well connection allows us to connect a new well for this producer but also allows us the ability to connect other producers in the area. The current processing capacity of the Minco facility is approximately 12 MMcf per day.

During the first three months of 2019, our mid-stream segment incurred $15.3 million in capital expenditures as compared to $7.3 million in the first three months of 2018. For 2019, our estimated capital expenditures range from approximately $35.0 million to $42.0 million.

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Contractual Commitments

At March 31, 2019, we had certain contractual obligations including:

	Payments Due by Period				
	Total	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
	(In thousands)				
Long-term debt (1)	$ 788,695	$ 44,659	$ 701,563	$ 42,473	$ —
Operating leases under ASC 840 (2)	3,016	2,262	754	—	—
Operating leases under ASC 842 (3)	4,649	2,582	1,959	24	84
Finance lease interest and maintenance (4)	4,220	2,154	2,066	—	—
Drill pipe, drilling components, and equipment purchases (5)	4,018	4,018	—	—	—
Total contractual obligations	$ 804,598	$ 55,675	$ 706,342	$ 42,497	$ 84

(1)See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our March 31, 2019 interest rates of 6.625% for the Notes and 4.0% for our Unit credit agreement. At March 31, 2019, our Unit credit agreement had a maturity date of October 18, 2023. The outstanding Unit credit facility balance was $40.0 million as of March 31, 2019.

(2)We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Canonsburg, Pennsylvania under the terms of operating leases expiring through December 2021. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3)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.

(4)Maintenance and interest payments are included in our finance lease agreements. The finance leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are $3.7 million and $0.5 million, respectively.

(5)We have committed to pay $4.0 million for drilling rig components, drill pipe, and related equipment over the next year.

During the second quarter of 2018, we entered into a contractual obligation that commits us to spend $150.0 million for drilling wells in the Granite Wash/Buffalo Wallow area over the next three years starting January 1, 2019. This amount is already included in our drilling plan. 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. If we elected not to drill or spend any money in the designated area over the three year period, the maximum amount we could forgo from distributions would be $87.0 million. Total spent towards the $150.0 million as of March 31, 2019 was $8.3 million.

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At March 31, 2019, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	**Total Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
	(In thousands)				
Deferred compensation plan (1)	$ 5,845	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 9,291	$ 781	Unknown	Unknown	Unknown
Asset retirement liability (3)	$ 67,840	$ 1,742	$ 40,837	$ 3,751	$ 21,510
Gas balancing liability (4)	$ 3,372	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$ 12,226	$ 4,864	$ 2,299	$ 1,077	$ 3,986
Finance lease obligations (7)	$ 10,395	$ 4,041	$ 6,354	$ —	$ —
Contract liability (8)	$ 9,173	$ 2,882	$ 5,201	$ 1,090	$ —

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 Unaudited Condensed 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 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 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. Currently there are no participants in the Senior 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 discounted 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 formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2011. One of our subsidiaries serves as the general partner of each of these programs. Effective December 31, 2014, The Unit 1984 Oil and Gas Limited Partnership dissolved and effective December 31, 2016, the two 1986 partnerships were dissolved. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, 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. Repurchases in any one year are limited to 20% of the units outstanding. We had no repurchases in the first three months of 2019 or 2018. The partnerships will be terminated during the second quarter of 2019 with an effective date of January 1, 2019.

6.We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

7.The amount includes commitments under finance lease arrangements for compressors in Superior.

8.We have recorded a liability related to the timing of revenue recognized on certain demand fees for Superior.

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.

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Commodity Derivatives. Our commodity derivatives are intended to 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. At March 31, 2019, based on our first quarter 2019 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	2019		
	Q2	Q3	Q4
Daily oil production	52%	52%	52%
Daily natural gas production	54%	54%	45%

With respect to the commodities subject to derivative contracts, those contracts serve to 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.

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our March 31, 2019 evaluation, we believe the risk of non-performance by our counterparties is not material. At March 31, 2019, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2019
	(In millions)
Bank of Montreal	$ 1.9
Bank of America	1.1
Total net assets	$ 3.0

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At March 31, 2019, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $3.5 million and non-current derivative liabilities of $0.5 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 non-current derivative liabilities of $0.3 million.

For our economic hedges any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Unaudited Condensed Consolidated Statements of Operations. These gains (losses) at March 31 are as follows:

	Three Months Ended March 31,	
	2019	2018
	(In thousands)	
Gain (loss) on derivatives:		
Loss on derivatives,	$ (6,932)	$ (6,762)

included are amounts settled during the period of $2,656 and ($2,073), respectively	$	(6,932)	$	(6,762)

Stock and Incentive Compensation

During the first three months of 2019, we granted awards covering 1,349,743 shares of restricted stock. These awards had an estimated fair value as of their grant date of $21.7 million. Compensation expense will be recognized over the three year vesting periods, and during the three months of 2019, we recognized $0.9 million in compensation expense and capitalized $0.1 million for these awards. During the first three months of 2019, we recognized compensation expense of $3.8 million for all of our restricted stock and capitalized $0.6 million of compensation cost for oil and natural gas properties.

During the first three months of 2018, we granted awards covering 1,201,568 shares of restricted stock. These awards had an estimated fair value as of their grant date of $23.4 million. Compensation expense will be recognized over the three year vesting periods, and during the three months of 2018, we recognized $1.0 million in compensation expense and capitalized $0.1 million for these awards. During the first three months of 2018, we recognized compensation expense of $5.5 million for all of our restricted stock and stock options and capitalized $0.4 million of compensation cost for oil and natural gas properties.

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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 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 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

New Accounting Pronouncements

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.

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, and early adoption is permitted. This amendment will not have a material impact on our 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 will be 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 12 – Leases.

Our internal control framework did not materially change because of this standard, but the existing internal controls have been modified to consider our new lease policy effective January 1, 2019. As we implement the new standard, we have added internal controls to ensure that we adequately evaluate new contracts under ASC 842.

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Results of Operations

Quarter Ended March 31, 2019 versus Quarter Ended March 31, 2018

Provided below is a comparison of selected operating and financial data:

	Quarter Ended March 31,		**Percent Change** (1)
	2019	**2018**	
	(In thousands unless otherwise specified)		
Total revenue	$ 189,691	$ 205,132	(8)%
Net income (loss)	$ (2,282)	$ 7,865	(129)%
Net income attributable to non-controlling interest	$ 1,222	$ —	—%
Net income (loss) attributable to Unit Corporation	$ (3,504)	$ 7,865	(145)%
Oil and Natural Gas:			
Revenue	$ 86,095	$ 103,099	(16)%
Operating costs excluding depreciation, depletion, and amortization	$ 32,714	$ 35,962	(9)%
Depreciation, depletion, and amortization	$ 35,767	$ 30,783	16%
Average oil price received (Bbl)	$ 56.29	$ 55.10	2 %
Average NGLs price received (Bbl)	$ 16.06	$ 21.08	(24)%
Average natural gas price received (Mcf)	$ 2.52	$ 2.62	(4)%
Oil production (Bbl)	688,000	736,000	(7)%
NGLs production (Bbl)	1,207,000	1,195,000	1 %
Natural gas production (Mcf)	13,371,000	13,499,000	(1)%
Depreciation, depletion, and amortization rate (Boe)	$ 8.28	$ 7.02	18%
Contract Drilling:			
Revenue	$ 51,155	$ 45,989	11%
Operating costs excluding depreciation	$ 31,401	$ 31,667	(1)%
Depreciation	$ 12,699	$ 13,312	(5)%
Percentage of revenue from daywork contracts	100 %	100 %	—%
	31.4	31.7	(1)%

Average number of drilling rigs in use			
Average dayrate on daywork contracts	$ 18,339	$ 17,038	8 %
Mid-Stream:			
Revenue	$ 52,441	$ 56,044	(6)%
Operating costs excluding depreciation and amortization	$ 39,355	$ 41,604	(5)%
Depreciation and amortization	$ 11,726	$ 11,053	6 %
Gas gathered—Mcf/day	449,916	372,862	21 %
Gas processed—Mcf/day	161,748	151,039	7 %
Gas liquids sold—gallons/day	650,614	577,560	13 %
Corporate and other:			
General and administrative expense	$ 9,741	$ 10,762	(9)%
Other depreciation	$ 1,934	$ 1,918	1 %
Gain (loss) on disposition of assets	$ (1,615)	$ 161	NM
Other income (expense):			
Interest income	$ 41	$ —	— %
Interest expense, net	$ (8,579)	$ (10,004)	(14)%
Loss on derivatives	$ (6,932)	$ (6,762)	3 %
Other	$ 5	$ 6	(17)%
Income tax expense (benefit)	$ (444)	$ 3,607	(112)%
Average long-term debt outstanding	$ 689,659	$ 821,178	(16)%
Average interest rate	6.6 %	6.1 %	8 %

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

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Oil and Natural Gas

Oil and natural gas revenues decreased $17.0 million or 16% in the first quarter of 2019 as compared to the first quarter of 2018 primarily due to lower unhedged NGLs and oil prices and from lower production volumes caused by a 14-day plant shut-down (12-days of which were in the first quarter of 2019) that resulted in a loss of slightly over 165 MBoe for the quarter. In the first quarter of 2019, as compared to the first quarter of 2018, oil production decreased 7%, natural gas production decreased 1%, and NGLs production increased 1%. Including derivatives settled, average oil prices increased 2% to $56.29 per barrel, average natural gas prices decreased 4% to $2.52 per Mcf, and NGLs prices decreased 24% to $16.06 per barrel.

Oil and natural gas operating costs decreased $3.2 million or 9% between the comparative first quarters of 2019 and 2018 primarily due to lower lease operating expenses partially offset by higher general and administrative expenses.

Depreciation, depletion, and amortization (DD&A) increased $5.0 million or 16% due primarily to an 18% increase in the DD&A rate partially offset by an 1% decrease in equivalent production. The increase in our DD&A rate in the first quarter of 2019 compared to the first quarter of 2018 resulted primarily from the cost of wells drilled in the last nine months of 2018 and the first quarter of 2019.

Contract Drilling

Drilling revenues increased $5.2 million or 11% in the first quarter of 2019 versus the first quarter of 2018. The increase was due primarily to an 8% increase in the average dayrate and $4.8 million received in early termination fees in the first quarter of 2019 partially offset by an 1% decrease in the average number of drilling rigs in use. Average drilling rig utilization decreased from 31.7 drilling rigs in the first quarter of 2018 to 31.4 drilling rigs in the first quarter of 2019.

Drilling operating costs decreased $0.3 million or 1% between the comparative first quarters of 2019 and 2018. The decrease was due primarily to less drilling rigs operating. Contract drilling depreciation decreased $0.6 million or 5% in the first quarter of 2019 versus the first quarter of 2018 also due to less drilling rigs operating and the transfer of 41 drilling rigs to assets held for sale.

Mid-Stream

Our mid-stream revenues decreased $3.6 million or 6% in the first quarter of 2019 as compared to the first quarter of 2018 due primarily to lower NGL prices and condensate prices. Gas processed volumes per day increased 7% between the comparative quarters primarily due to additional wells connected to several of our processing systems. Gas gathered volumes per day increased 21% between the comparative quarters primarily due to connecting additional wells to our gathering and processing facilities primarily in Pennsylvania and Oklahoma.

Operating costs decreased $2.2 million or 5% in the first quarter of 2019 compared to the first quarter of 2018 primarily due to lower gas purchase prices offset by a $255,970 monthly service fee for outside services not incurred in the first quarter of 2018. Depreciation and amortization increased $0.7 million, or 6%, primarily due to new capital assets placed in service.

Gain (Loss) on Disposition of Assets

There was a $1.6 million loss on disposition of assets in the first quarter of 2019. Of this amount, $0.6 million was related to assets held for sale that were sold which consisted of three drilling rigs and other drilling rig components. The other $1.0 million was related to the sales of other drilling rig components and vehicles. For the first quarter of 2018, we had a gain of $0.2 million for the disposition of assets primarily due to the sale of vehicles.

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $1.4 million between the comparative first quarters of 2019 and 2018 due primarily to a 16% decrease in average long-term debt outstanding in the first quarter of 2019 and increased interest capitalized partially offset by a higher average interest rate. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the first quarter of 2019 was $4.2 million compared to $3.6 million in the first quarter of 2018, and was netted against our gross interest of $12.8 million and $13.6 million for the first quarters of 2019 and 2018, respectively. Our average interest rate increased from 6.1% in the first quarter of 2018 to 6.6% in the first quarter of 2019 and our average

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debt outstanding was $131.5 million lower in the first quarter of 2019 as compared to the first quarter of 2018 primarily due to the pay down of the Unit credit agreement in the second quarter of 2018.

Loss on Derivatives

Loss on derivatives increased by $0.2 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense decreased $4.1 million between the comparative first quarters of 2019 and 2018 primarily due to decreased pre-tax income and elimination of non-controlling interest income. Our effective tax rate was 16.3% for the first quarter of 2019 compared to 31.4% for the first quarter of 2018. The rate change was primarily due decreased pre-tax income, elimination of non-controlling interest income, and a smaller impact to deferred taxes related to our restricted stock vestings in the comparative first quarters of 2019 and 2018. There was no current income tax expense in the first quarter of 2019. We paid no income taxes in the first quarter of 2019. Under the guidance in ASC 810, *Consolidation,* we have determined that Superior is a VIE. The tax effects related to the gain recognized on the sale in 2018 have been recorded to Capital in excess of par value.

Safe Harbor Statement

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases, and oral statements issued by or on our behalf, contain, or may contain, certain statements that are “forward-looking statements” within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address 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 expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, 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 legal proceedings involving us 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 or natural gas production to established pipeline systems;
•impact of federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;

• our projected production guidelines for the year;

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•our anticipated capital budgets;
•our financial condition and liquidity;
•the number of wells our oil and natural gas segment plans to drill or rework during the year;
•our intended use of the proceeds from the sale of 50% of the interest we owned in our mid-stream segment; and
•our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

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

•the risk factors discussed in this report and in the documents we incorporate by reference;
•general economic, market, or business conditions;
•the availability of and nature of (or lack of) business opportunities that 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;
•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 intention 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 report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Our operations are exposed to market risks primarily because of changes in commodity prices 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. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, these prices have fluctuated and we expect this to continue. The prices for oil, NGLs, and natural gas also affect the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first three months 2019 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $431,000 per month ($5.2 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $220,000 per month ($2.6 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 hedging, would have a $387,000 per month ($4.6 million annualized) change in our pre-tax operating cash flow.

We use derivative transactions to manage the risk associated with price volatility. Our decisions regarding the amount and prices at which we choose to enter into a contract for certain of our products 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
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production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At March 31, 2019, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'19 – Oct'19	Natural gas – swap	60,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Nov'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Apr'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Apr'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Apr'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Apr'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Apr'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreements and the Notes. The credit agreement, 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 the first three months of 2019, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $0.4 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).

Our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) (Disclosure Controls) or our internal control over financial reporting (as defined in Rules 13a - 15(f) and 15d - 15(f) of the Exchange Act) (ICFR) 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.

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 under the Exchange Act in providing reasonable assurance that the information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Based on that evaluation, our CEO and CFO concluded that our Disclosure Controls were effective as of
pending effectiveness testing on the remediation of the material weakness in ICFR that was identified during the second quarter of 2018 as described below.

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

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

We did not design and maintain effective controls to verify the proper presentation and disclosure of the interim and annual consolidated financial statements. Specifically, our controls were not sufficiently precise to allow for the effective review of the underlying information used in the preparation of the consolidated financial statements, nor verify that transactions were appropriately presented. The material weakness resulted in the revision of the Company's consolidated financial statements as of and for the year ended December 31, 2017, the restatement of the Company’s condensed consolidated financial statements for the quarter ended March 31, 2018 and immaterial adjustments related to the classification of accounts receivable and accounts payable for the quarters ended June 30, 2018 and September 30, 2018. This material weakness could result in a material misstatement of the annual or interim consolidated financial statements or disclosures that would not be prevented or detected.

e the second quarter of 2018, management has dedicated significant time and resources that we believe will address the underlying cause of the material weakness, including:

•engaged a consultant specializing in internal controls to assist with the remediation efforts;
•recruited, added, and trained an additional staff position in the financial reporting department;
•redesigned and enhanced controls related to the preparation and review of the consolidated financial statements;
•provided additional training to financial reporting personnel with respect to the preparation and review of the consolidated financial statements;
•recruited an additional staff position specifically over compliance of internal controls; and

Management believes the measures described above have remediated the material weakness that we have identified pending effectiveness testing as described above. This material weakness will not be considered remediated until the applicable remedial controls operate for a sufficient period of time. As management continues to evaluate and improve internal control over financial reporting, we may decide to take additional measures to address this control deficiency or determine to modify certain of the remediation measures.

There were no other changes in our ICFR, as defined in Rule 13a – 15(f) under the Exchange Act, during the quarter ended that materially affected our ICFR or are reasonably likely to materially affect it.

PART II. OTHER INFORMATION

Item 1. 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 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, the Plaintiffs filed a second request to certify a class of royalty owners slightly smaller than their first attempt. Since then, the Plaintiffs have further amended their proposed class to just include royalty owners entitled to royalties under certain leases in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. In July 2014, a second class certification hearing was held where, besides the defenses described above, we argued that the amended class definition is still deficient under the court of civil appeals opinion reversing the initial class certification. Closing arguments were held on December 2, 2014. There is no timetable for when the court will issue its ruling. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

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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 untimely royalty payments under Oklahoma's Production Revenue Standards Act. The lawsuit seeks actual and punitive damages, an accounting, disgorgement, injunctive relief, and attorney's fees. Plaintiff is seeking relief on behalf of royalty 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. At this point, the court has not taken any action on the issue of class certification.

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. We filed a motion to dismiss on the basis that the claims asserted by the Plaintiff and the putative class are barred because they have already been asserted by the putative class in the Panola lawsuit and are subject to its reversal of class certification. The court denied our motion to dismiss and we have asked the court to certify its order so that it can be immediately appealed. That issue is still pending before the court. If we do not ultimately prevail on our claim of issue preclusion, we have several other 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 wrongfully withheld. At this point, the issue of class certification has not been set before the court.

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 1A. Risk Factors

In addition to the other information set forth in this quarterly report, you should carefully consider the factors discussed below, if any, and in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2018, which could materially affect our business, financial condition, or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2018.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information relating to our repurchase of common stock for the three months ended March 31, 2019:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share (2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2019 to January 31, 2019	—	$ —	—	—
February 1, 2019 to February 28, 2019				—
March 1, 2019 to March 31, 2019	291,167	13.99	291,167	—
Total	291,167	$ 13.99	291,167	—

1.The shares were repurchased to remit withholding of taxes on the value of stock distributed with the first quarter 2019 vesting of restricted stock for grants previously made from our "Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015."

2.The price paid per common share represents the closing sales price of a share of our common stock as reported by the NYSE on the day that the stock was acquired by us.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibits:

31.1	Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act.
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.
101.INS	XBRL Instance 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.

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*Certain schedules referenced in the agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule will be furnished supplementary to the U.S. Securities and Exchange Commission upon request.

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SIGNATURES

Pursuant to the requirements 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:	May 2, 2019	By: /s/ Larry D. Pinkston
		LARRY D. PINKSTON
		Chief Executive Officer and Director
Date:	May 2, 2019	By: /s/ Les Austin
		LES AUSTIN
		Senior Vice President and Chief Financial Officer