UNIT CORP
Form 10-Q
November 06, 2018
Table of Contents

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 September 30, 2018
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 October 19, 2018, 54,058,016 shares of the issuer's common stock were outstanding.

Table of Contents

TABLE OF CONTENTS

1

Table of Contents

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;
- 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 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.

Table of Contents

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.

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2018	December 31, 2017
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 91,557	$ 701
Accounts receivable, net of allowance for doubtful accounts of $2,450 at both September 30, 2018 and December 31, 2017, respectively	122,123	111,512
Materials and supplies	505	505
Current derivative asset (Note 10)	—	721
Prepaid expenses and other	9,419	6,233
Total current assets	223,604	119,672
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,901,661	5,712,813
Unproved properties not being amortized	332,886	296,764
Drilling equipment	1,632,540	1,593,611
Gas gathering and processing equipment	751,715	726,236
Saltwater disposal systems	67,074	62,618
Corporate land and building	59,081	59,080
Transportation equipment	29,103	29,631
Other	56,750	53,439
	8,830,810	8,534,192
Less accumulated depreciation, depletion, amortization, and impairment	6,325,160	6,151,450
Net property and equipment	2,505,650	2,382,742
Goodwill	62,808	62,808
Other assets	28,703	16,230
Total assets (1)	$ 2,820,765	$ 2,581,452

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

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	September 30, 2018	December 31, 2017
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 143,552	$ 112,648
Accrued liabilities (Note 5)	67,743	48,523
Income taxes payable	1,051	—
Current derivative liability (Note 10)	13,067	7,763
Current portion of other long-term liabilities (Note 6)	14,150	13,002
Total current liabilities	239,563	181,936
Long-term debt less debt issuance costs (Note 6)	643,921	820,276
Non-current derivative liability (Note 10)	1,542	—
Other long-term liabilities (Note 6)	101,410	100,203
Deferred income taxes	164,964	133,477
Commitments and contingencies (Note 12)	—	—
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, 54,063,705 and 52,880,134 shares issued as of September 30, 2018 and December 31, 2017, respectively	10,414	10,280
Capital in excess of par value	626,746	535,815
Accumulated other comprehensive income (loss) (Note 14)	(103)	63
Retained earnings	830,680	799,402
Total shareholders' equity attributable to Unit Corporation	1,467,737	1,345,560
Non-controlling interests in consolidated subsidiaries	201,628	—
Total shareholders' equity	1,669,365	1,345,560
Total liabilities[1] and shareholders' equity	$ 2,820,765	$ 2,581,452

(1) Unit Corporation's consolidated total assets as of September 30, 2018 include total current and long-term assets of its variable interest entity (VIE) (Superior Pipeline Company, L.L.C.) of $41.8 million and $416.7 million, respectively, which can only be used to settle obligations of the VIE. Unit Corporation's consolidated total liabilities as of September 30, 2018 include total current and long-term liabilities of the VIE of $38.6 million and $16.1 million, respectively, for which the creditors of the VIE have no recourse to Unit Corporation. See Note 13 – Variable Interest Entity Arrangements.

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

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED INCOME STATEMENTS (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$111,623	$85,470	$317,040	$256,241
Contract drilling	50,612	51,619	143,527	128,059
Gas gathering and processing	57,823	51,399	167,926	150,493
Total revenues	220,058	188,488	628,493	534,793
Expenses:				
Operating costs:				
Oil and natural gas	32,139	33,911	100,519	95,873
Contract drilling	32,032	34,747	95,593	91,213
Gas gathering and processing	43,134	38,116	124,441	111,862
Total operating costs	107,305	106,774	320,553	298,948
Depreciation, depletion, and amortization	63,537	54,533	178,976	151,545
General and administrative	9,278	9,235	28,752	26,902
Gain on disposition of assets	(253)	(81)	(575)	(1,153)
Total operating expenses	179,867	170,461	527,706	476,242
Income from operations	40,191	18,027	100,787	58,551
Other income (expense):				
Interest, net	(7,945)	(9,944)	(25,678)	(28,807)
Gain (loss) on derivatives	(4,385)	(2,614)	(25,608)	21,019
Other, net	6	5	17	14
Total other income (expense)	(12,324)	(12,553)	(51,269)	(7,774)
Income before income taxes	27,867	5,474	49,518	50,777
Income tax expense:				
Deferred	6,744	1,769	12,380	22,084
Total income taxes	6,744	1,769	12,380	22,084
Net income	21,123	3,705	37,138	28,693
Net income attributable to non-controlling interest	2,224	—	4,586	—
Net income attributable to Unit Corporation	18,899	3,705	32,552	28,693
Net income attributable to Unit Corporation per common share:				
Basic	$0.36	$0.07	$0.63	$0.56
Diluted	$0.36	$0.07	$0.62	$0.56

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

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Net income	$21,123	$3,705	$37,138	$28,693
Other comprehensive income (loss), net of taxes:				
Unrealized gain (loss) on securities, net of tax of ($13), $20, ($60) and $32	(38)	33	(179)	53
Comprehensive income	21,085	3,738	36,959	28,746
Less: Comprehensive income attributable to non-controlling interest	2,224	—	4,586	—
Comprehensive income attributable to Unit Corporation	$18,861	$3,738	$32,373	$28,746

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

Table of Contents

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	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 adjustment for adoption of ASUs (Notes 1 and 2)	—	—	13	(1,274)	—	(1,261)
Net income	—	—	—	32,552	4,586	37,138
Other comprehensive loss (net of tax of ($60))	—	—	(179)	—	—	(179)
Total comprehensive income						36,959
Contributions	—	102,958	—	—	197,042	300,000
Transaction costs associated with sale of non-controlling interest	—	(2,303)	—	—	—	(2,303)
Tax effect of the sale of non-controlling interest	—	(24,300)	—	—	—	(24,300)
Activity in employee compensation plans (1,183,571 shares)	134	14,576	—	—	—	14,710
Balances, September 30, 2018	$10,414	$626,746	$ (103)	$830,680	$ 201,628	$1,669,365

	Shareholders' Equity Attributable to Unit Corporation					
	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income	Retained Earnings	Non-controlling Interest in Consolidated Subsidiaries	Total
	(In thousands except per share amounts)					
Balances, December 31, 2016	$10,016	$502,500	$ —	$681,554	$ —	$1,194,070
Net income	—	—	—	28,693	—	28,693
Other comprehensive income (net of tax of $32)	—	—	53	—	—	53
Total comprehensive income						28,746
Activity in employee compensation plans (1,385,342 shares)	261	28,828	—	—	—	29,089
Balances, September 30, 2017	$10,277	$531,328	$ 53	$710,247	$ —	$1,251,905

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

Table of Contents

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

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$37,138	$28,693
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	178,976	151,545
Amortization of debt issuance costs and debt discount (Note 6)	1,645	1,616
(Gain) loss on derivatives (Note 10)	25,608	(21,019)
Cash payments on derivatives settled, net (Note 10)	(18,040)	(729)
Deferred tax expense	12,380	22,084
Gain on disposition of assets	(575)	(1,153)
Stock compensation plans	17,397	12,478
Contract assets and liabilities, net (Note 2)	(3,671)	—
Other, net	2,835	1,397
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(15,558)	(36,381)
Accounts payable	(14,867)	4,873
Material and supplies	—	17
Income taxes	—	(15)
Accrued liabilities	16,242	20,280
Other, net	(2,975)	1,106
Net cash provided by operating activities	236,535	184,792
INVESTING ACTIVITIES:		
Capital expenditures	(304,054)	(167,392)
Producing properties and other acquisitions	(769)	(55,429)
Proceeds from disposition of assets	25,316	20,137
Other	—	(1,500)
Net cash used in investing activities	(279,507)	(204,184)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	71,200	251,401
Payments under credit agreement	(249,200)	(250,100)
Payments on capitalized leases	(2,869)	(2,967)
Proceeds from common stock issued, net of issue costs (Note 14)	—	18,623
Proceeds from investments of non-controlling interest	300,000	—
Transaction costs associated with sale of non-controlling interest	(2,303)	—
Book overdrafts	17,000	2,364
Net cash provided by financing activities	133,828	19,321
Net increase (decrease) in cash and cash equivalents	90,856	(71)
Cash and cash equivalents, beginning of period	701	893
Cash and cash equivalents, end of period	$91,557	$822

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

9

Table of Contents

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

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	14,418	14,601
Income taxes	3,600	—
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	(28,770)	(20,122)
Non-cash (addition) reduction to oil and natural gas properties related to asset retirement obligations	8,546	(3,203)

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

Table of Contents

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 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 13 – 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 27, 2018, for the year ended December 31, 2017 as amended by our Form 10-K/A filed on August 6, 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 September 30, 2018 and December 31, 2017;
- Income Statements for the three and nine months ended September 30, 2018 and 2017;
- Statements of Comprehensive Income for the three and nine months ended September 30, 2018 and 2017;
- Statements of Changes in Shareholders' Equity for the nine months ended September 30, 2018 and 2017; and
- Statements of Cash Flows for the nine months ended September 30, 2018 and 2017.

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 nine months ended September 30, 2018 and 2017 are not necessarily indicative of the results we may realize for the full year of 2018, or that we realized for the full year of 2017.

Accounting Changes - Recent Accounting Pronouncements - Adopted

As of January 1, 2018, we adopted ASU 2018-02 Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. This standard is explained further in Note 8 - New Accounting Pronouncements. We adopted this amendment early and it had no material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and we now use 24.5%. This change is reflected in our Unaudited Condensed Consolidated Statements of Comprehensive Income and in Note 14 - Equity.

Also, as of January 1, 2018, we adopted ASU 2014-09 Revenue from Contracts with Customers - Topic 606 (ASC 606) and all later amendments that modified ASC 606. This new revenue standard is explained further in Note 8 – New Accounting Pronouncements. We elected to apply this standard on the modified retrospective approach method to contracts not completed as of January 1, 2018, where the cumulative effect on adoption, which only affected our mid-stream segment, is recognized as an adjustment to opening retained earnings at January 1, 2018. This adjustment related to the timing of revenue recognition for certain demand fees. Our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by the ASU are included in Note 2 – Revenue from Contracts with Customers.

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 15 – Industry Segment Information). Revenue from the oil and natural gas segment is derived from sales of our oil and natural gas production. Revenue from the contract drilling segment is derived by contracting with upstream companies to drill an agreed-on number of wells or provide

Table of Contents

drilling rigs and services over an agreed-on time period. Revenue from the mid-stream segment is derived from gathering, transporting, and processing natural gas production and selling those commodities. We sell the hydrocarbons (from the oil and natural gas and mid-stream segments) to mid-stream and downstream oil and gas companies.

We satisfy the performance obligation under each segment's contracts as follows: for the contract drilling and mid-stream contracts, we satisfy the performance obligation over the agreed-on time within the contracts, and for oil and natural gas contracts, we satisfy the performance obligation with each delivery of volumes. For oil and natural gas contracts, as it is more feasible, we account for these deliveries monthly. Per the contracts for all segments, customers pay for the services/goods received monthly within an agreed on number of days following the end of the month. Besides the mid-stream demand fees discussed further below, there were no other contract assets or liabilities falling within the scope of this accounting pronouncement.

Oil and Natural Gas Contracts, Revenues, Implementation Impact to Retained Earnings, and Performance Obligations

Typical types of revenue contracts signed by our segments are Oil Sales Contracts, Gas Purchase Agreements, North American Energy Standards Board (NAESB) Contracts, Gas Gathering and Processing Agreements, and revenues earned as the non-operated party with the operator serving as an agent on our behalf under our Joint Operating Agreements. Contract term can range from a single month to a term spanning a decade or more; some may also include evergreen provisions. Revenues from sales we make are recognized when our customer obtains control of the sold product. For sales to other mid-stream and downstream oil and gas companies, this would occur at a point in time, typically on delivery to the customer. Sales generated from our non-operated interest are recorded based on the information obtained from the operator. Our adoption of this standard required no adjustment to opening retained earnings.

Certain costs—as either a deduction from revenue or as an expense—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. The impact of the adoption of ASC 606 did not impact income from operations or net income for the three or nine months ended September 30, 2018. These tables summarize the impact of the adoption of ASC 606 on revenue and operating costs for the three and nine months ended September 30, 2018, respectively:

	Three Months Ended September 30, 2018		
	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Oil and natural gas revenues	$111,623	$ (5,200)	$116,823
Oil and natural gas operating costs	32,139	(5,200)	37,339
Gross profit	$79,484	$ —	$79,484

	Nine Months Ended September 30, 2018		
	As Reported	Adjustments due to ASC	Amounts without

		606	the Adoption of ASC 606
	(In thousands)		
Oil and natural gas revenues	$317,040	$ (12,102)	$329,142
Oil and natural gas operating costs	100,519	(12,102)	112,621
Gross profit	$216,521	$ —	$216,521

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

Table of Contents

and circumstances, we consider the transfer of control of the asset in a commodity sale to occur at the point the commodity transfers to our purchaser.

Most of the consideration received by us for oil and gas sales is variable. Most of our contracts state the consideration is calculated by multiplying a variable quantity by an agreed-on index price less deductions related to gathering, transportation, fractionation, and related fuel charges. There are also instances where the consideration is quantity multiplied by a weighted average sales price. These different pricing tools can change the perception of when control transfers; however, when analyzed with other control factors, typically the accounting conclusion is the same for both pricing methods. In these instances, the variable consideration is partially constrained. In addition, all variable consideration is settled at the end of the month; therefore, whether the variability is constrained does not affect accounting for revenue under ASC 606 as the variability is known prior to each reporting period. An estimation and allocation of transaction price and future obligations are not required.

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

The contracts our drilling segment uses are primarily industry standard IADC contracts model year 2003 and 2013. Contract terms range from six months to three or more years or can be based on terms to drill a specific number of wells. The allocation rules in ASC 606 (called the "series guidance") provide that a contract may contain a single performance obligation composed of a series of distinct goods or services if 1) each distinct good or service is substantially the same and would meet the criteria to be a performance obligation satisfied over time and 2) each distinct good or service is measured using the same method as it relates to the satisfaction of the overall performance obligation. We have determined that the delivery of drilling services is within the scope of the series guidance as both criteria noted above are met. Specifically, 1) each distinct increment of service (i.e. hour available to drill) that the drilling contractor promises to transfer represents a performance obligation that would meet the criteria for recognizing revenue over time, and 2) the drilling contractor would use the same method for measuring progress toward satisfaction of the performance obligation for each distinct increment of service in the series. At inception, the total transaction price will be estimated to include any applicable fixed consideration, unconstrained variable consideration (estimated day rate mobilization and demobilization revenue, estimated operating day rate revenue to be earned over the contract term, expected bonuses (if material and can be reasonably estimated without significant reversal), and penalties (if material and can be reasonably estimated without significant reversal)). Allocation rules under this new standard allow us to recognize revenues associated with our drilling contacts in materially the same manner as under the previous revenue accounting standard. A contract liability will be recorded for consideration received before the corresponding transfer of services. Those liabilities will generally only arise in relation to upfront mobilization fees paid in advance and are allocated/recognized over the entire performance obligation. Such balances will be amortized over the recognition period based on the same method of measure used for revenue. On adoption of the standard, no adjustment to opening retained earnings was required.

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

All consideration received for contract drilling is variable, excluding termination fees, which we have concluded will not apply to our contracts as of the reporting date. The consideration is calculated by multiplying a variable quantity (number of days/hours) by an agreed-on daily price (for the daily rate, mobilization and demobilization revenue). Other revenue items under the contract may include bonus/penalty revenue, reimbursable revenue, drilling fluid rates, and early termination fees. All variable consideration is not constrained but is settled at the end of the month; therefore, whether the variability is constrained or not does not affect accounting for revenue under ASC 606 as the variability is known before each reporting period excluding certain bonuses/penalties which might be based on activity that occurs over the entire term of the contract. We have evaluated the mobilization and de-mobilization charges on outstanding contracts, however, the impact to the financial statements was immaterial. As of September 30, 2018, we had 34 contract drilling contracts (21 of which are long-term) for a duration of two months to almost three years.

Table of Contents

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

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

Revenues are generated from the fees earned for gas gathering and processing services provided to a customer. The typical revenue contracts used by this segment are gas gathering and processing agreements. Contract terms range from a single month to terms spanning a decade or more, some include evergreen provisions. Fees for mid-stream services (gathering, transportation, processing) are performance obligations and meet the criteria of over time recognition which could be considered a series of distinct performance obligations that represents one overall performance obligation of gas gathering and processing services.

On adoption of the standard, an adjustment to opening retained earnings was made for $1.7 million ($1.3 million, net of tax). This adjustment—related to the timing of revenue recognized on certain demand fees—impacted our Unaudited Condensed Consolidated Balance Sheet (for the periods indicated) as follows:

	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
	(In thousands)		
Assets:			
Other assets	$16,230	$ 10,798	$27,028
Liabilities and shareholders' equity:			
Current portion of other long-term liabilities	13,002	2,748	15,750
Other long-term liabilities	100,203	9,737	109,940
Deferred income taxes	133,477	(413)	133,064
Retained earnings	799,402	(1,274)	798,128

At September 30, 2018:

	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Assets:			
Prepaid expenses and other	$9,419	$ 206	$ 9,213
Other assets	28,703	12,383	16,320
Liabilities and shareholders' equity:			
Current portion of other long-term liabilities	14,150	2,874	11,276
Other long-term liabilities	101,410	7,731	93,679
Deferred income taxes	164,964	486	164,478
Retained earnings	830,680	1,498	829,182

14

Table of Contents

For the three months ended September 30, 2018:

	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Gas gathering and processing revenues	$57,823	$ 1,300	$ 56,523
Deferred income tax expense	6,744	318	6,426
Net income	21,123	982	20,141

This adjustment related to the timing of revenue recognized on certain demand fees and had the following impact to the Unaudited Condensed Consolidated Income Statement for the nine months ended September 30, 2018:

	As Reported	Adjustments due to ASC 606	Amounts without the Adoption of ASC 606
	(In thousands)		
Gas gathering and processing revenues	$167,926	$ 3,671	$164,255
Deferred income tax expense	12,380	899	11,481
Net income	37,138	2,772	34,366

The only fixed consideration related to mid-stream consideration is a demand fee calculated by multiplying an agreed-on price by a fixed number of volumes per month over a specified term in the contract.

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	October - December 2018	2019	2020	2021	2022	Total Remaining Impact to Revenue
		(In thousands)					
Demand fee contracts	4-5 years	$1,299	$2,632	$(3,781)	$(3,507)	$1,374	$ (1,983)

Before implementing ASC 606, we immediately recognized the entire demand fee since the fee was payable within the first five years from the effective date of the contract and not over the entire term of the contract. However, as the demand fee does not specifically relate to a distinct performance obligation, under the new standard that amount should now be recognized over the life of the contract. Therefore, the demand fee previously recognized for $1.7 million ($1.3 million, net of tax) was adjusted to retained earnings as of January 1, 2018 and will be recognized over the remaining term of the contract. As this amount is fixed, recognition of the remaining portion will be stable. Besides the demand fee, there were no other contract assets or liabilities (see above for the balance sheet line items where they are reported). For the three and nine months ended September 30, 2018, $1.3 million and $3.7 million, respectively, was recognized in revenue for these demand fees.

	September 30, 2018	January 1, 2018	Change

	(In thousands)		
Contract assets	$12,589	$10,798	$1,791
Contract liabilities	10,605	12,485	(1,880)
Contract assets (liabilities), net	$1,984	$(1,687)	$3,671

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

Table of Contents

days following the end of the month and includes payment for all services performed that month. Our overall performance obligation is satisfied at the end of the contract term.

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

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

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

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

NOTE 3 – DIVESTITURES

Divestitures

Oil and Natural Gas

We sold non-core oil and natural gas assets, net of related expenses, for $22.3 million during the first nine months of 2018, compared to $18.0 million during the first nine months of 2017. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

Mid-Stream

On April 3, 2018, we sold 50% of the ownership interest in our mid-stream segment, Superior. The purchaser is SP Investor Holdings, LLC, a holding company jointly owned by OPTrust and funds managed and/or advised by Partners Group, a global private markets investment manager. We received $300.0 million because of this sale. A portion of the proceeds were used to pay down our bank debt and the remainder will accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company, make additional capital investments in the jointly owned Superior, and for general working capital purposes. In connection with the sale of the interest in Superior, we took the necessary actions under the Indenture governing our outstanding senior subordinated notes to secure the ability to close the sale and have Superior released from the Indenture.

Superior will be governed and managed under its Amended and Restated Limited Liability Company Agreement and the Master Services and Operating Agreement (MSA) signed by Superior and an affiliate of Unit, as both agreements may be amended occasionally. Further details are in Note 13 – Variable Interest Entity Arrangements.

Table of Contents

NOTE 4 – EARNINGS PER SHARE

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

	Earnings (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended September 30, 2018			
Basic earnings attributable to Unit Corporation per common share	$18,899	52,068	$ 0.36
Effect of dilutive stock options and restricted stock	—	1,072	—
Diluted earnings attributable to Unit Corporation per common share	$18,899	53,140	$ 0.36
For the three months ended September 30, 2017			
Basic earnings attributable to Unit Corporation per common share	$3,705	51,386	$ 0.07
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	586	—
Diluted earnings attributable to Unit Corporation per common share	$3,705	51,972	$ 0.07

The following table shows the number of stock options and SARs (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 September 30,	
	2018	2017
Stock options and SARs	66,500	178,755
Average exercise price	$44.42	$47.75

	Earnings (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2018			
Basic earnings attributable to Unit Corporation per common share	$32,552	51,951	$ 0.63
Effect of dilutive stock options and restricted stock	—	808	(0.01)
Diluted earnings attributable to Unit Corporation per common share	$32,552	52,759	$ 0.62
For the nine months ended September 30, 2017			
Basic earnings attributable to Unit Corporation per common share	$28,693	51,019	$ 0.56
Effect of dilutive stock options, restricted stock, and SARs	—	550	—
Diluted earnings attributable to Unit Corporation per common share	$28,693	51,569	$ 0.56

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

	Nine Months Ended September 30,	
	2018	2017
Stock options and SARs	66,500	178,755
Average exercise price	$44.42	$47.75

17

Table of Contents

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of:

	September 30, 2018	December 31, 2017
	(In thousands)	
Employee costs	$17,880	$ 19,521
Interest payable	17,446	6,745
Lease operating expenses	11,474	11,819
Taxes	10,317	3,404
Derivative settlements	3,383	—
Third-party credits	2,099	2,240
Other	5,144	4,794
Total accrued liabilities	$67,743	$ 48,523

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

Long-Term Debt

Our long-term debt as of the dates indicated consisted of the following:

	September 30, 2018	December 31, 2017
	(In thousands)	
Unit credit agreement with an average interest rate of 3.4% at December 31, 2017	$—	$ 178,000
Superior credit agreement	—	—
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	650,000	828,000
Less: unamortized discount	(1,780)	(2,234)
Less: debt issuance costs, net	(4,299)	(5,490)
Total long-term debt	$643,921	$ 820,276

Unit Credit Agreement. On October 18, 2018, we signed a Fifth Amendment to our Senior Credit Agreement (Unit credit agreement) originally scheduled to mature on April 10, 2020. The details of this amendment are discussed in Note 17 – Subsequent Events and have not been incorporated into the discussion of the Unit credit agreement immediately below.

On April 2, 2018, we entered into a fourth amendment to the Unit credit agreement (Fourth Amendment). The Fourth Amendment provided, among other things, for a reduction of the maximum credit amount from $875.0 million to $425.0 million, a reduction in the borrowing base from $475.0 million to $425.0 million, a reduction in the total commitment amount from $475.0 million to $425.0 million; and the full release of Superior and its subsidiaries as a borrower and co-obligor under the Unit credit agreement. Under the amendment, once the sale of the interest in Superior was completed, we had to use part of the proceeds to pay down the Unit credit agreement. The Superior sale closed on April 3, 2018 and the pay down was made that day.

On May 2, 2018, the company signed 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.

We are charged a commitment fee of 0.50% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. We paid $1.0 million in previous origination, agency, syndication, and other related fees. We incurred no additional fees related to the fourth amendment. We are amortizing these fees over the life of the Unit credit agreement. Under the Unit credit agreement, we have pledged as collateral 85% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties.

Table of Contents

The borrowing base amount is subject to redetermination by the lenders on April 1st and October 1st of each year and 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 2.00% to 3.00% 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. 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 September 30, 2018, we had no outstanding borrowings under the Unit credit agreement.

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

The Unit credit agreement prohibits, among other things:

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

Effective September 30, 2018, 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 September 30, 2018, we were in compliance with the Unit credit agreement 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.

Superior is charged a commitment fee of 0.375% on the amount available but not borrowed which varies based on the amount borrowed as a percentage of the total borrowing base. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio of not greater than 4.00 to 1.00. The Superior credit 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 September 30, 2018, Superior was in compliance with the Superior credit agreement 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.

Table of Contents

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.

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. 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 September 30, 2018.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2018	December 31, 2017
	(In thousands)	
Asset retirement obligation (ARO) liability	$62,727	$ 69,444
Workers’ compensation	12,832	13,340
Capital lease obligations	12,355	15,224
Contract liability	10,605	—
Separation benefit plans	8,135	6,524
Deferred compensation plan	5,623	5,390
Gas balancing liability	3,283	3,283

	115,560	113,205
Less current portion	14,150	13,002
Total other long-term liabilities	$101,410	$ 100,203

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 October 1, 2018 (and through 2023) are $14.1 million, $43.1 million, $659.8 million, $4.6 million, and $2.3 million, respectively.

Table of Contents

Capital Leases

In 2014, Superior entered into capital 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 capital lease obligations is included in current portion of other long-term liabilities and the non-current portion of $8.4 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of September 30, 2018. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are $4.6 million and $0.8 million, respectively, at September 30, 2018. Annual payments, net of maintenance and interest, average $4.2 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.

Future payments required under the capital leases at September 30, 2018 are:

Beginning October 1,	Amount (In thousands)
2018	$ 6,195
2019	6,195
2020	5,322
Total future payments	17,712
Less payments related to:	
Maintenance	4,601
Interest	756
Present value of future minimum payments	$ 12,355

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 AROs for the periods indicated:

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
ARO liability, January 1:	$69,444	$70,170
Accretion of discount	1,829	2,112
Liability incurred	244	1,123
Liability settled	(3,907)	(1,350)
Liability sold	(105)	(1,563)
Revision of estimates [1]	(4,778)	4,993
ARO liability, September 30:	62,727	75,485
Less current portion	1,451	2,947
Total long-term ARO	$61,276	$72,538

(1) Plugging liability estimates were revised in both 2018 and 2017 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.

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, 2019, and interim periods within those years. This amendment will not have a material impact on our financial statements.

Income Taxes - Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118. In March 2018, the FASB issued ASU 2018-05 which updates the FASB’s Accounting Standards Codification to reflect the guidance in SAB 118, which adds Section EE, “Income Tax Accounting Implications of the Tax Cuts and Jobs Act,” to SAB Topic 5, “Miscellaneous Accounting.” SAB 118 also provides guidance on applying ASC 740, Income Taxes, if the accounting for certain income tax effects of the Tax Cuts and Jobs Act of 2017 is incomplete when the financial statements are issued for a reporting period.

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.

Leases. The FASB has issued several accounting standards updates and amendments related to leases in the past two years, which are codified within Topic 842. For public companies, these are effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. The standard requires lessees to recognize at the commencement date of a lease a lease liability, which represents the lessee's obligation to make lease payments arising from the lease, measured on a discounted basis; and a right-of-use asset, which represents the lessee's right to use a specified asset for the lease term. Other recently issued amendments to Topic 842 have provided clarifying guidance regarding land easements, an additional modified retrospective transition method, and added several practical expedients to apply Topic 842 for both lessees and lessors. The standard will not apply to leases of mineral rights.

We have an implementation team working through the provisions of the new guidance including a review of different types of contracts to document our lease portfolio and assess the impact on our accounting, disclosures, processes, internal control over financial reporting, and the election of certain practical expedients. Our evaluation of the impact of the new guidance on our financial statements is on-going.

We have made certain accounting policy decisions including that we plan to adopt the short-term lease recognition exemption, accounting for certain asset classes at a portfolio level, and establishing a balance sheet recognition capitalization threshold. Our transition will utilize the modified retrospective approach to adopting the new standard, and will be applied at the beginning of the period adopted (January 1, 2019) in accordance with ASU 2018-11. We expect to elect the transition practical expedient, which allows us to not evaluate land easements that existed prior to January 1, 2019, and the optional transition method to record the adoption impact through a cumulative adjustment to equity. We expect for certain lessee asset classes to elect the practical expedient and not separate lease and nonlease components. For these asset classes, we will account for the agreements as a single lease component.

We expect for certain lessor asset classes to elect the practical expedient and not separate lease and nonlease components and determine the appropriate accounting based on the predominate component of the contract. The assessment of predominance is ongoing.

We anticipate a material impact to the balance sheet across segments as we recognize Right of Use assets and liabilities but no material impact to the income statement (from the lessee's perspective). The assessment of the dollar value impact of adoption is on-going.

Adopted Standards

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. The FASB issued ASU 2018-02, an amendment which provides financial statement preparers with an option to reclassify stranded tax effects within AOCI to retained earnings caused by the Tax Cuts and Jobs Act of 2017. The amendment is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. Organizations should apply the

Table of Contents

proposed amendments either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Tax Cuts and Jobs Act is recognized. We adopted this amendment early and it had no material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and now we are using 24.5%. The change is reflected in our Unaudited Condensed Consolidated Statements of Comprehensive Income and in Note 14 - Equity.

Revenue from Contracts with Customers. Effective January 1, 2018, we adopted ASC 606. This new revenue standard provides for a five-step analysis of transactions to determine when and how revenue is to be recognized. The guidance in this update supersedes the revenue recognition requirements in ASC 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Under the standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. We applied the five-step method outlined in the ASU to all our revenue streams in the scope of ASC 606 and elected the modified retrospective approach method. Under that approach the cumulative effect on adoption is recognized as an adjustment to opening retained earnings at January 1, 2018. Only our mid-stream segment was affected. This adjustment related to the timing of revenue on certain demand fees. Both our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by ASC 606 have been included in Note 2 – Revenue from Contracts with Customers.

Our internal control framework did not materially change because of this standard, but the existing internal controls have been modified to consider our new revenue recognition policy effective January 1, 2018. As we implement the new standard, we have added internal controls to ensure that we adequately evaluate new contracts under the five-step model under ASU 2014-09.

NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Recognized stock compensation expense	$4.1	$ 3.2	$ 13.6	$ 9.0
Capitalized stock compensation cost for our oil and natural gas properties	0.6	0.5	1.6	1.3
Tax benefit on stock-based compensation	1.0	1.2	3.3	3.4

The remaining unrecognized compensation cost related to unvested awards at September 30, 2018 is approximately $19.0 million, of which $2.4 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."

Table of Contents

We granted no SARs or stock options during either of the three or nine month periods ending September 30, 2018 or 2017. We did not grant any restricted stock awards during either of the three month periods ending September 30, 2018 or 2017. This table shows the fair value of restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Nine Months Ended September 30, 2018		Nine Months Ended September 30, 2017	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	844,498	362,070	475,799	173,373
Non-employee directors	44,312	—	49,104	—
	888,810	362,070	524,903	173,373
Estimated fair value (in millions):[(1)]				
Employees	$16.2	$ 7.3	$11.8	$ 4.5
Non-employee directors	0.9	—	0.9	—
	$17.1	$ 7.3	$12.7	$ 4.5
Percentage of shares granted expected to be distributed:				
Employees	95 %	74 %	95 %	91 %
Non-employee directors	100 %	N/A	100 %	N/A

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(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 nine months of 2018 and 2017 are being recognized over a three-year vesting period. During the first quarter of 2018 and 2017, 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 September 30, 2018, the participants are estimated to receive 49% of the 2018, 92% of the 2017, and 170% of the 2016 performance-based shares. The CFTA performance measurement at September 30, 2018 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 2018 awards for the first nine months of 2018 was $7.5 million.

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 September 30, 2018, 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.

Table of Contents

- 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 September 30, 2018, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'18	Natural gas – swap	30,000 MMBtu/day	$3.005	IF – NYMEX (HH)
Nov'18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – swap	10,000 MMBtu/day	$2.810	IF – NYMEX (HH)
Oct'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.190)	NGPL TEXOK
Oct'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.678)	PEPL
Oct'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.568)	NGPL MIDCON
Nov'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jan'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
Oct'18 – Dec'18	Natural gas – three-way collar	20,000 MMBtu/day	$3.00 - $2.50 - $3.51	IF – NYMEX (HH)
Oct'18 – Dec'18	Crude oil – swap	4,000 Bbl/day	$53.52	WTI – NYMEX
Oct'18 – Dec'18	Crude oil – price differential risk	500 Bbl/day	$7.00	LLS/WTI
Oct'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Jan'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

After September 30, 2018, the following derivatives were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'19 – Dec'19	Natural gas – swap	10,000 MMBtu/day	$2.850	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Jan'19 – Mar'19	Natural gas – three-way collar	10,000 MMBtu/day	$3.00 - $2.75 - $4.35	IF – NYMEX (HH)

Table of Contents

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 September 30, 2018	December 31, 2017
		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	$ —	$ 721
Long-term	Non-current derivative asset	—	—
Total derivative assets		$ —	$ 721

	Balance Sheet Location	Derivative Liabilities Fair Value September 30, 2018	December 31, 2017
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liability	$ 13,067	$ 7,763
Long-term	Non-current derivative liability	1,542	—
Total derivative liabilities		$ 14,609	$ 7,763

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 Income Statements for the three months ended September 30:

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative 2018	2017
		(In thousands)	
Commodity derivatives	Loss on derivatives [1]	$ (4,385)	$ (2,614)
Total		$ (4,385)	$ (2,614)

(1) Amounts settled during the 2018 and 2017 periods include net payments of $9.1 million and net proceeds of $0.8 million, respectively.

Following is the effect of derivative instruments on the Unaudited Condensed Consolidated Income Statements for the nine months ended September 30:

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative 2018	2017
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives [1]	$ (25,608)	$ 21,019
Total		$ (25,608)	$ 21,019

(1) Amounts settled during the 2018 and 2017 periods include net payments of $18.0 million and $0.7 million, respectively.

Table of Contents

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:				
September 30, 2018	$830	$ —	$ 137	$ 693
December 31, 2017	$830	$ 102	$ —	$ 932

During the second quarter of 2017, we received available-for-sale securities for early termination fees associated with a long-term drilling contract. We will 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 impairment charge will be recorded, and a new cost basis established. We will review 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.

Table of Contents

The following tables set forth our recurring fair value measurements:

	September 30, 2018				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$—	$1,282	$88	$(1,370)	$—
Liabilities	—	(8,372)	(7,607)	1,370	(14,609)
Total commodity derivatives	—	(7,090)	(7,519)	—	(14,609)
Equity securities	693	—	—	—	693
	$693	$(7,090)	$(7,519)	$—	$(13,916)

	December 31, 2017				
	Level 1	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$—	$2,137	$3,344	$(4,760)	$721
Liabilities	—	(8,973)	(3,550)	4,760	(7,763)
Total commodity derivatives	$—	$(6,836)	$(206)	$—	$(7,042)
Equity securities	932	—	—	—	932
	$932	$(6,836)	$(206)	$—	$(6,110)

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 September 30, 2018.

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.

28

Table of Contents

The following table is a reconciliation of our level 3 fair value measurements:

	Net Derivatives			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Beginning of period	$(6,135)	$4,093	$(206)	$(7,122)
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	(3,700)	(2,015)	(12,324)	9,102
Settlements	2,316	(592)	5,011	(494)
End of period	$(7,519)	$1,486	$(7,519)	$1,486
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$(1,384)	$(2,607)	$(7,313)	$8,608

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

The following table provides quantitative information about our Level 3 unobservable inputs at September 30, 2018:

Commodity [(1)]	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil three-way collars	$ (7,607)	Discounted cash flow	Forward commodity price curve	$0 - $17.65
Natural gas three-way collars	$ 88	Discounted cash flow	Forward commodity price curve	$0 - $0.12

(1) The commodity contracts detailed in this category include non-exchange-traded crude oil and natural gas three-way 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 September 30, 2018 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 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 the estimated fair value amounts.

At September 30, 2018, 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.

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 our credit agreements approximate their fair value and at September 30, 2018 we did not have any outstanding borrowings under either the Unit or Superior credit agreement. Borrowings from our Unit credit agreement at December 31, 2017 were $178.0 million. These borrowings would be 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 September 30, 2018 and December 31, 2017 were $643.9 million and $642.3 million, respectively. We estimate the fair value of the Notes using quoted marked prices at September 30, 2018 and December 31, 2017 was $655.5 million and $649.7 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 – COMMITMENTS AND CONTINGENCIES

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. 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. Future minimum rental payments under the terms of the leases are approximately $5.1 million, $2.1 million, $0.6 million, and less than $0.1 million in twelve-month periods beginning October 1, 2018 (and through 2021), respectively. Total rent expense incurred was $7.2 million and $6.4 million for the first nine months of 2018 and 2017, respectively.

In 2014, Superior signed capital lease agreements for 20 compressors with initial terms of seven years. Estimated annual capital lease payments under the terms during the four successive twelve-month periods beginning October 1, 2018 (and through the end of 2021) are $6.2 million, $6.2 million, and $5.3 million. Total maintenance and interest remaining related to these leases are $4.6 million and $0.8 million, respectively at September 30, 2018. Annual payments, net of maintenance and interest, average $4.2 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 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 made repurchases of approximately $1,700 and $2,900 in the first nine months of 2018 and 2017, respectively.

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 risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the drilling rig is on the location and the cost has been included in the direct cost of drilling the well.

During the second quarter of 2018, as part of the Superior transaction, we entered into a contractual obligation that commits us to spend $150.0 million to drill wells in the Granite Wash/Buffalo Wallow area over three years starting January 1, 2019. This amount is 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.

For the next twelve months, we have committed to purchase approximately $10.1 million of new drilling rig components.

NOTE 13 – VARIABLE INTEREST ENTITY ARRANGEMENTS

On April 3, 2018 we sold 50% of the ownership interest in Superior. The 50% interest in Superior we sold was acquired by SP Investor Holdings, LLC, a holding company jointly owned by OPTrust and funds managed and/or advised by Partners Group, a global private markets investment manager. Superior will be governed and managed under the Amended and Restated Limited Liability Company Agreement and the MSA. The MSA is between our affiliate, SPC Midstream Operating, L.L.C. (the Operator) and Superior. The Operator is owned 100% by Unit Corporation. Under the guidance in ASC 810, Consolidation, we have determined that Superior is a VIE. The two variable interests applicable to Unit include the 50% equity investment in Superior and the MSA. The MSA houses the power to direct the activities that most significantly impact Superior's operating performance. The MSA is a separate variable interest. Unit through the MSA has the power to direct Superior’s most significant activities; reciprocally the equity investors lack the power to direct the activities that most significantly impact the entity’s economic performance. Because of this, Unit is considered the primary beneficiary. There have been no changes to the primary beneficiary during the quarter ended September 30, 2018.

Table of Contents

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 $250,000. 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:

	September 30, 2018 (In thousands)
Current assets:	
Cash and cash equivalents	$ 9,039
Accounts receivable	29,991
Prepaid expenses and other	2,756
Total current assets	41,786
Property and equipment:	
Gas gathering and processing equipment	751,715
Transportation equipment	3,064
	754,779
Less accumulated depreciation, depletion, amortization, and impairment	353,476
Net property and equipment	401,303
Other assets	15,411
Total assets	$ 458,500
Current liabilities:	
Accounts payable	$ 28,183
Accrued liabilities	3,574
Current portion of other long-term liabilities	6,836
Total current liabilities	38,593
Long-term debt less debt issuance costs	—
Other long-term liabilities	16,126
Total liabilities	$ 54,719

NOTE 14 – EQUITY

At-the-Market (ATM) Common Stock Program

On April 4, 2017, we signed a Distribution Agreement (the Agreement) with a sales agent, under which we could offer and sell, from time to time, through the sales agent shares of our common stock, par value $.20 per share (the Shares), up to an aggregate offering price of $100.0 million. Net proceeds from any of these sales could be used to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

Table of Contents

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

Accumulated Other Comprehensive Income (Loss)

Components of accumulated other comprehensive income (loss) were as follows for the three months ended September 30:

	2018	2017
	(In thousands)	
Unrealized appreciation on securities, before tax	$(51)	$53
Tax benefit (expense)	13 (1)	(20)
Unrealized appreciation on securities, net of tax	$(38)	$33

(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 (loss) by component, net of tax, for the three months ended September 30 are as follows:

	Net Gains on Equity Securities	
	2018	2017
	(In thousands)	
Balance at June 30:	$(65)	$ 20
Unrealized appreciation (loss) before reclassifications	(38) (1)	33
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive income (loss)	(38)	33
Balance at September 30:	$(103)	$ 53

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

Components of accumulated other comprehensive income (loss) were as follows for the nine months ended September 30:

	2018	2017
	(In thousands)	
Unrealized appreciation (loss) on securities, before tax	$(239)	$85
Tax benefit (expense)	60 (1)	(32)
Unrealized appreciation (loss) on securities, net of tax	$(179)	$53

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

Table of Contents

Changes in accumulated other comprehensive income by component, net of tax, for the nine months ended September 30 are as follows:

	Net Gains on Equity Securities	
	2018	2017
	(In thousands)	
Balance at December 31, 2017	$63	$ —
Adjustment due to ASU 2018-02	13 (1)	—
Balance at January 1:	76	—
Unrealized appreciation (loss) before reclassifications	(179) (1)	53
Amounts reclassified from accumulated other comprehensive income	—	—
Net current-period other comprehensive income (loss)	(179)	53
Balance at September 30:	$(103)	$ 53

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

NOTE 15 – 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.

Table of Contents

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

	Three Months Ended September 30, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$111,623	$—	$ —	$—	$ —	$ 111,623
Contract drilling	—	58,012	—	—	(7,400)	50,612
Gas gathering and processing	—	—	82,882	—	(25,059)	57,823
Total revenues	111,623	58,012	82,882	—	(32,459)	220,058
Expenses:						
Operating costs:						
Oil and natural gas	33,400	—	—	—	(1,261)	32,139
Contract drilling	—	38,246	—	—	(6,214)	32,032
Gas gathering and processing	—	—	66,932	3,808	(27,606)	43,134
Total operating costs	33,400	38,246	66,932	3,808	(35,081)	107,305
Depreciation, depletion, and amortization	35,460	14,889	11,265	1,923	—	63,537
Total expenses	68,860	53,135	78,197	5,731	(35,081)	170,842
General and administrative	—	—	—	9,278	—	9,278
Gain on disposition of assets	(7)	(230)	(16)	—	—	(253)
Income (loss) from operations	42,770	5,107	4,701	(15,009)	2,622	40,191
Loss on derivatives	—	—	—	(4,385)	—	(4,385)
Interest, net	—	—	(381)	(7,564)	—	(7,945)
Other	—	—	—	3,814	(3,808)	6
Income (loss) before income taxes	$42,770	$5,107	$ 4,320	$(23,144)	$ (1,186)	$ 27,867

(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.

Table of Contents

	Three Months Ended September 30, 2017					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$85,470	$—	$ —	$—	$ —	$ 85,470
Contract drilling	—	55,588	—	—	(3,969)	51,619
Gas gathering and processing	—	—	69,057	—	(17,658)	51,399
Total revenues	85,470	55,588	69,057	—	(21,627)	188,488
Expenses:						
Operating costs:						
Oil and natural gas	35,082	—	—	—	(1,171)	33,911
Contract drilling	—	38,115	—	—	(3,368)	34,747
Gas gathering and processing	—	—	54,602	—	(16,486)	38,116
Total operating costs	35,082	38,115	54,602	—	(21,025)	106,774
Depreciation, depletion, and amortization	26,460	15,280	10,880	1,913	—	54,533
Total expenses	61,542	53,395	65,482	1,913	(21,025)	161,307
General and administrative expense	—	—	—	9,235	—	9,235
(Gain) loss on disposition of assets	1	(68)	(14)	—	—	(81)
Income (loss) from operations	23,927	2,261	3,589	(11,148)	(602)	18,027
Loss on derivatives	—	—	—	(2,614)	—	(2,614)
Interest, net	—	—	—	(9,944)	—	(9,944)
Other	—	—	—	5	—	5
Income (loss) before income taxes	$23,927	$2,261	$ 3,589	$(23,701)	$ (602)	$ 5,474

Table of Contents

	Nine Months Ended September 30, 2018					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues: [1]						
Oil and natural gas	$317,040	$—	$ —	$—	$ —	$ 317,040
Contract drilling	—	161,489	—	—	(17,962)	143,527
Gas gathering and processing	—	—	232,938	—	(65,012)	167,926
Total revenues	317,040	161,489	232,938	—	(82,974)	628,493
Expenses:						
Operating costs:						
Oil and natural gas	104,234	—	—	—	(3,715)	100,519
Contract drilling	—	111,121	—	—	(15,528)	95,593
Gas gathering and processing	—	—	185,738	7,384	(68,681)	124,441
Total operating costs	104,234	111,121	185,738	7,384	(87,924)	320,553
Depreciation, depletion, and amortization	97,797	41,927	33,493	5,759	—	178,976
Total expenses	202,031	153,048	219,231	13,143	(87,924)	499,529
General and administrative expense	—	—	—	28,752	—	28,752
Gain on disposition of assets	(136)	(314)	(95)	(30)	—	(575)
Income (loss) from operations	115,145	8,755	13,802	(41,865)	4,950	100,787
Loss on derivatives	—	—	—	(25,608)	—	(25,608)
Interest, net	—	—	(834)	(24,844)	—	(25,678)
Other	—	—	—	7,401	(7,384)	17
Income (loss) before income taxes	$115,145	$8,755	$ 12,968	$(84,916)	$ (2,434)	$ 49,518

(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.

Table of Contents

	Nine Months Ended September 30, 2017					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$256,241	$—	$ —	$—	$ —	$ 256,241
Contract drilling	—	137,617	—	—	(9,558)	128,059
Gas gathering and processing	—	—	198,632	—	(48,139)	150,493
Total revenues	256,241	137,617	198,632	—	(57,697)	534,793
Expenses:						
Operating costs:						
Oil and natural gas	99,349	—	—	—	(3,476)	95,873
Contract drilling	—	99,794	—	—	(8,581)	91,213
Gas gathering and processing	—	—	156,525	—	(44,663)	111,862
Total operating costs	99,349	99,794	156,525	—	(56,720)	298,948
Depreciation, depletion, and amortization	71,544	41,896	32,547	5,558	—	151,545
Total expenses	170,893	141,690	189,072	5,558	(56,720)	450,493
General and administrative expense	—	—	—	26,902	—	26,902
Gain on disposition of assets	(176)	(106)	(58)	(813)	—	(1,153)
Income (loss) from operations	85,524	(3,967)	9,618	(31,647)	(977)	58,551
Gain on derivatives	—	—	—	21,019	—	21,019
Interest, net	—	—	—	(28,807)	—	(28,807)
Other	—	—	—	14	—	14
Income (loss) before income taxes	$85,524	$(3,967)	$ 9,618	$(39,421)	$ (977)	$ 50,777

NOTE 16 – 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.

Table of Contents

Condensed Consolidating Balance Sheets (Unaudited)

	September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$82,267	$251	$ 9,039	$—	$91,557
Accounts receivable, net of allowance for doubtful accounts of $2,450 (Guarantor of $1,245 and Non-Guarantor of $1,205)	1,374	92,078	28,671	—	122,123
Materials and supplies	—	505	—	—	505
Current derivative asset	—	—	—	—	—
Prepaid expenses and other	3,125	3,538	2,756	—	9,419
Total current assets	86,766	96,372	40,466	—	223,604
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	5,901,661	—	—	5,901,661
Unproved properties not being amortized	—	332,886	—	—	332,886
Drilling equipment	—	1,632,540	—	—	1,632,540
Gas gathering and processing equipment	—	—	751,715	—	751,715
Saltwater disposal systems	—	67,074	—	—	67,074
Corporate land and building	—	59,081	—	—	59,081
Transportation equipment	9,273	16,766	3,064	—	29,103
Other	28,506	28,244	—	—	56,750
	37,779	8,038,252	754,779	—	8,830,810
Less accumulated depreciation, depletion, amortization, and impairment	25,922	5,945,762	353,476	—	6,325,160
Net property and equipment	11,857	2,092,490	401,303	—	2,505,650
Intercompany receivable	907,907	—	—	(907,907)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,248,309	1,500	—	(1,248,309)	1,500
Other assets	5,605	6,186	15,412	—	27,203
Total assets	$2,260,444	$2,259,356	$ 457,181	$(2,156,216)	$2,820,765

Table of Contents

	September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$28,116	$90,543	$ 24,893	$—	$143,552
Accrued liabilities	36,444	26,583	4,716	—	67,743
Income taxes payable	1,051	—	—	—	1,051
Current derivative liability	13,067	—	—	—	13,067
Current portion of other long-term liabilities	966	6,348	6,836	—	14,150
Total current liabilities	79,644	123,474	36,445	—	239,563
Intercompany debt	—	906,296	1,086	(907,382)	—
Bonds payable less debt issuance costs	643,921	—	—	—	643,921
Non-current derivative liabilities	1,542	—	—	—	1,542
Other long-term liabilities	12,790	72,494	16,126	—	101,410
Deferred income taxes	54,707	110,257	—	—	164,964
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, 54,063,705 shares issued	10,414	—	—	—	10,414
Capital in excess of par value	626,746	45,921	197,042	(242,963)	626,746
Contributions from Unit	—	—	525	(525)	—
Accumulated other comprehensive loss	—	(103)	—	—	(103)
Retained earnings	830,680	1,001,017	4,329	(1,005,346)	830,680
Total shareholders' equity attributable to Unit Corporation	1,467,840	1,046,835	201,896	(1,248,834)	1,467,737
Non-controlling interests in consolidated subsidiaries	—	—	201,628	—	201,628
Total shareholders' equity	1,467,840	1,046,835	403,524	(1,248,834)	1,669,365
Total liabilities and shareholders' equity	$2,260,444	$2,259,356	$ 457,181	$(2,156,216)	$2,820,765

Table of Contents

	December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$510	$191	$—	$—	$701
Accounts receivable, net of allowance for doubtful accounts of $2,450 (Guarantor of $1,245 and Non-Guarantor of $1,205)	154	83,442	27,916	—	111,512
Materials and supplies	—	505	—	—	505
Current derivative asset	721	—	—	—	721
Prepaid expenses and other	2,986	2,370	877	—	6,233
Total current assets	4,371	86,508	28,793	—	119,672
Property and equipment:					
Oil and natural gas properties on the full cost method:					
Proved properties	—	5,712,813	—	—	5,712,813
Unproved properties not being amortized	—	296,764	—	—	296,764
Drilling equipment	—	1,593,611	—	—	1,593,611
Gas gathering and processing equipment	—	—	726,236	—	726,236
Saltwater disposal systems	—	62,618	—	—	62,618
Corporate land and building	—	59,080	—	—	59,080
Transportation equipment	9,270	17,423	2,938	—	29,631
Other	28,039	25,400	—	—	53,439
	37,309	7,767,709	729,174	—	8,534,192
Less accumulated depreciation, depletion, amortization, and impairment	21,268	5,807,757	322,425	—	6,151,450
Net property and equipment	16,041	1,959,952	406,749	—	2,382,742
Intercompany receivable	1,155,725	—	—	(1,155,725)	—
Goodwill	—	62,808	—	—	62,808
Investments	1,044,709	1,500	—	(1,044,709)	1,500
Other assets	5,373	6,328	3,029	—	14,730
Total assets	$2,226,219	$2,117,096	$ 438,571	$(2,200,434)	$2,581,452

Table of Contents

	December 31, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
LIABILITIES AND SHAREHOLDERS’ EQUITY					
Current liabilities:					
Accounts payable	$13,124	$81,334	$ 18,190	$—	$112,648
Accrued liabilities	26,165	19,134	3,224	—	48,523
Current derivative liability	7,763	—	—	—	7,763
Current portion of other long-term liabilities	657	8,501	3,844	—	13,002
Total current liabilities	47,709	108,969	25,258	—	181,936
Intercompany debt	—	870,582	285,143	(1,155,725)	—
Long-term debt	178,000	—	—	—	178,000
Bonds payable less debt issuance costs	642,276	—	—	—	642,276
Other long-term liabilities	11,257	77,566	11,380	—	100,203
Deferred income taxes	1,480	85,443	46,554	—	133,477
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, 52,880,134 shares issued	10,280	—	—	—	10,280
Capital in excess of par value	535,815	45,921	15,549	(61,470)	535,815
Accumulated other comprehensive income	—	63	—	—	63
Retained earnings	799,402	928,552	54,687	(983,239)	799,402
Total shareholders’ equity attributable to Unit Corporation	1,345,497	974,536	70,236	(1,044,709)	1,345,560
Non-controlling interests in consolidated subsidiaries	—	—	—	—	—
Total shareholders' equity	1,345,497	974,536	70,236	(1,044,709)	1,345,560
Total liabilities and shareholders’ equity	$2,226,219	$2,117,096	$ 438,571	$(2,200,434)	$2,581,452

Table of Contents

Condensed Consolidating Statements of Income (Unaudited)

	Three Months Ended September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$—	$ 169,635	$ 82,882	$ (32,459)	$ 220,058
Expenses:					
Operating costs	—	71,646	66,932	(31,273)	107,305
Depreciation, depletion, and amortization	1,923	50,349	11,265	—	63,537
General and administrative	—	9,252	26	—	9,278
Gain on disposition of assets	—	(237)	(16)	—	(253)
Total operating costs	1,923	131,010	78,207	(31,273)	179,867
Income from operations	(1,923)	38,625	4,675	(1,186)	40,191
Interest, net	(7,564)	—	(381)	—	(7,945)
Loss on derivatives	(4,385)	—	—	—	(4,385)
Other, net	6	(1)	1	—	6
Income (loss) before income taxes	(13,866)	38,624	4,295	(1,186)	27,867
Income tax expense (benefit)	(3,688)	9,839	593	—	6,744
Equity in net earnings from investment in subsidiaries, net of taxes	29,077	—	—	(29,077)	—
Net income	18,899	28,785	3,702	(30,263)	21,123
Less: net income attributable to non-controlling interest	—	—	2,224	—	2,224
Net income attributable to Unit Corporation	$18,899	$ 28,785	$ 1,478	$ (30,263)	$ 18,899

	Three Months Ended September 30, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$—	$ 141,058	$ 69,057	$ (21,627)	$ 188,488
Expenses:					
Operating costs	—	73,197	54,603	(21,026)	106,774
Depreciation, depletion, and amortization	1,913	41,740	10,880	—	54,533
General and administrative	—	7,083	2,152	—	9,235
Gain on disposition of assets	—	(67)	(14)	—	(81)
Total operating costs	1,913	121,953	67,621	(21,026)	170,461
Income (loss) from operations	(1,913)	19,105	1,436	(601)	18,027
Interest, net	(9,776)	—	(168)	—	(9,944)
Loss on derivatives	(2,614)	—	—	—	(2,614)
Other, net	5	—	—	—	5
Income (loss) before income taxes	(14,298)	19,105	1,268	(601)	5,474
Income tax expense (benefit)	(5,626)	7,003	392	—	1,769
Equity in net earnings from investment in subsidiaries, net of taxes	12,377	—	—	(12,377)	—
Net income	3,705	12,102	876	(12,978)	3,705
Less: net income attributable to non-controlling interest	—	—	—	—	—
Net income attributable to Unit Corporation	$3,705	$ 12,102	$ 876	$ (12,978)	$ 3,705

Table of Contents

	Nine Months Ended September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$—	$ 478,529	$ 232,938	$ (82,974)	$ 628,493
Expenses:					
Operating costs	—	215,355	185,738	(80,540)	320,553
Depreciation, depletion, and amortization	5,759	139,724	33,493	—	178,976
General and administrative	—	26,136	2,616	—	28,752
Gain on disposition of assets	(30)	(450)	(95)	—	(575)
Total operating costs	5,729	380,765	221,752	(80,540)	527,706
Income (loss) from operations	(5,729)	97,764	11,186	(2,434)	100,787
Interest, net	(24,844)	—	(834)	—	(25,678)
Loss on derivatives	(25,608)	—	—	—	(25,608)
Other, net	17	—	—	—	17
Income (loss) before income taxes	(56,164)	97,764	10,352	(2,434)	49,518
Income tax expense (benefit)	(14,356)	25,299	1,437	—	12,380
Equity in net earnings from investment in subsidiaries, net of tax	74,360	—	—	(74,360)	—
Net income	32,552	72,465	8,915	(76,794)	37,138
Less: net income attributable to non-controlling interest	—	—	4,586	—	4,586
Net income attributable to Unit Corporation	$32,552	$ 72,465	$ 4,329	$ (76,794)	$ 32,552

	Nine Months Ended September 30, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Revenues	$—	$ 393,858	$ 198,632	$ (57,697)	$ 534,793
Expenses:					
Operating costs	—	199,143	156,525	(56,720)	298,948
Depreciation, depletion, and amortization	5,558	113,440	32,547	—	151,545
General and administrative	—	20,880	6,022	—	26,902
Gain on disposition of assets	(813)	(282)	(58)	—	(1,153)
Total operating costs	4,745	333,181	195,036	(56,720)	476,242
Income (loss) from operations	(4,745)	60,677	3,596	(977)	58,551
Interest, net	(28,276)	—	(531)	—	(28,807)
Gain on derivatives	21,019	—	—	—	21,019
Other, net	14	—	—	—	14
Income (loss) before income taxes	(11,988)	60,677	3,065	(977)	50,777
Income tax expense (benefit)	(4,895)	25,357	1,622	—	22,084
Equity in net earnings from investment in subsidiaries, net of tax	35,786	—	—	(35,786)	—
Net income	28,693	35,320	1,443	(36,763)	28,693
Less: net income attributable to non-controlling interest	—	—	—	—	—
Net income attributable to Unit Corporation	$28,693	$ 35,320	$ 1,443	$ (36,763)	$ 28,693

Table of Contents

Condensed Consolidating Statements of Comprehensive Income (Unaudited)

	Three Months Ended September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income	$18,899	$ 28,785	$ 3,702	$ (30,263)	$ 21,123
Other comprehensive income, net of taxes:					
Unrealized loss on securities, net of tax ($13)	—	(38)	—	—	(38)
Comprehensive income	18,899	28,747	3,702	(30,263)	21,085
Less: Comprehensive income attributable to non-controlling interests	—	—	2,224	—	2,224
Comprehensive income attributable to Unit Corporation	$18,899	$ 28,747	$ 1,478	$ (30,263)	$ 18,861

	Three Months Ended September 30, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income	$3,705	$ 12,102	$ 876	$ (12,978)	$ 3,705
Other comprehensive income, net of taxes:					
Unrealized gain on securities, net of tax of $20	—	33	—	—	33
Comprehensive income	3,705	12,135	876	(12,978)	3,738
Less: Comprehensive income attributable to non-controlling interests	—	—	—	—	—
Comprehensive income attributable to Unit Corporation	$3,705	$ 12,135	$ 876	$ (12,978)	$ 3,738

	Nine Months Ended September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income	$32,552	$ 72,465	$ 8,915	$ (76,794)	$ 37,138
Other comprehensive income, net of taxes:					
Unrealized loss on securities, net of tax of ($60)	—	(179)	—	—	(179)
Comprehensive income	32,552	72,286	8,915	(76,794)	36,959
Less: Comprehensive income attributable to non-controlling interests	—	—	4,586	—	4,586
Comprehensive income attributable to Unit Corporation	$32,552	$ 72,286	$ 4,329	$ (76,794)	$ 32,373

	Nine Months Ended September 30, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
Net income	$28,693	$ 35,320	$ 1,443	$ (36,763)	$ 28,693
Other comprehensive income, net of taxes:					
Unrealized gain on securities, net of tax of $32	—	53	—	—	53
Comprehensive income	28,693	35,373	1,443	(36,763)	28,746
	—	—	—	—	—

Less: Comprehensive income attributable to non-controlling interests					
Comprehensive income attributable to Unit Corporation	$28,693	$ 35,373	$ 1,443	$ (36,763)	$ 28,746

44

Table of Contents

Condensed Consolidating Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	(103,436)	215,350	(3,984)	128,605	236,535
INVESTING ACTIVITIES:					
Capital expenditures	22	(275,434)	(28,642)	—	(304,054)
Producing properties and other acquisitions	—	(769)	—	—	(769)
Proceeds from disposition of assets	30	25,199	87	—	25,316
Net cash provided by (used in) investing activities	52	(251,004)	(28,555)	—	(279,507)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	69,200	—	2,000	—	71,200
Payments under credit agreement	(247,200)	—	(2,000)	—	(249,200)
Intercompany borrowings (advances), net	248,343	35,714	(155,977)	(128,080)	—
Payments on capitalized leases	—	—	(2,869)	—	(2,869)
Proceeds from investments of non-controlling interest	102,958	—	197,042	—	300,000
Contributions from Unit	—	—	525	(525)	—
Transaction costs associated with sale of non-controlling interest	(2,303)	—	—	—	(2,303)
Book overdrafts	14,143	—	2,857	—	17,000
Net cash provided by financing activities	185,141	35,714	41,578	(128,605)	133,828
Net increase in cash and cash equivalents	81,757	60	9,039	—	90,856
Cash and cash equivalents, beginning of period	510	191	—	—	701
Cash and cash equivalents, end of period	$ 82,267	$ 251	$ 9,039	$ —	$ 91,557

	Nine Months Ended September 30, 2017				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Consolidating Adjustments	Total Consolidated
	(In thousands)				
OPERATING ACTIVITIES:					
Net cash provided by operating activities	822	149,963	34,007	—	184,792
INVESTING ACTIVITIES:					
Capital expenditures	(3,595)	(152,055)	(11,742)	—	(167,392)
Producing properties and other acquisitions	—	(55,429)	—	—	(55,429)
Proceeds from disposition of assets	955	19,124	58	—	20,137
Other	—	(1,500)	—	—	(1,500)
Net cash used in investing activities	(2,640)	(189,860)	(11,684)	—	(204,184)
FINANCING ACTIVITIES:					
Borrowings under credit agreement	251,401	—	—	—	251,401
Payments under credit agreement	(250,100)	—	—	—	(250,100)
Intercompany borrowings (advances), net	(20,483)	39,839	(19,356)	—	—
Payments on capitalized leases	—	—	(2,967)	—	(2,967)
Proceeds from common stock issued, net of issue costs	18,623	—	—	—	18,623
Book overdrafts	2,364	—	—	—	2,364
Net cash provided by (used in) financing activities	1,805	39,839	(22,323)	—	19,321

Net decrease in cash and cash equivalents	(13)	(58)	—	—	(71)
Cash and cash equivalents, beginning of period	517	376	—	—	893
Cash and cash equivalents, end of period	$504	$ 318	$ —	$ —	$ 822

45

Table of Contents

NOTE 17 – SUBSEQUENT EVENT

On October 18, 2018, we signed the fifth amendment to the Unit credit agreement originally scheduled to mature on April 10, 2020. The Fifth Amendment, among other things, (i) extends the term of the Unit credit agreement to October 18, 2023, subject to certain conditions; (ii) reduces the pricing for borrowing and non-use fees; and (iii) eliminates the requirement that the company maintain a senior indebtedness to consolidated EBITDA ratio. The total commitment of credit and the borrowing base both remain unchanged at $425.0 million.

A copy of the Fifth Amendment is filed as Exhibit 10.1 to this report.

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 (and any amendments thereto) 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 oil and natural gas segment.

Business Outlook

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

Fluctuating commodity prices worldwide during the past several years brought about significant and adverse changes to our industry and us. Industry wide reductions in drilling activity and spending reduced the rates for and the number of our drilling rigs we were able to put to work.

Recently, commodity prices have improved. Reflecting that improvement, during the first quarter of 2018, our oil and natural gas segment put four of our drilling rigs to work and increased the number to six drilling rigs for a brief period during

Table of Contents

the third quarter of 2018. We have subsequently reduced our operated rig count. Our contract drilling segment finished constructing its 11th BOSS drilling rig and that drilling rig was placed into service in mid-July. During the second quarter and third quarter of 2018, we were awarded term contracts to build our 12th and 13th BOSS drilling rigs. Construction is in progress and the drilling rigs will be placed into service in the first quarter of 2019. Rig utilization fluctuated over the past year due to commodity prices changing and budget constraints on operators in the fourth quarter of 2017. We expect commodity prices and budget constraints on operators to continue to affect rig utilization through 2018.

Other recent improvements:

- We have not incurred a non-cash ceiling test write-down since 2016. We had no write-down in the third quarter of 2018 nor the third quarter of 2017. It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at September 30, 2018, and only adjust the 12-month average price to an estimated fourth quarter ending average (holding October 2018 prices constant for the remaining two months of the fourth quarter of 2018), our forward looking expectation is that we will not recognize an impairment in the fourth quarter of 2018. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for a future impairment.

- In 2018, our oil and natural gas segment plans to participate in drilling 95-105 wells (depending on future commodity prices). In 2017, we drilled 70 wells up from 21 in 2016 due to increased cash flow resulting from improvement in commodity prices.

On April 3, 2018, the company completed the sale of 50% of the ownership interests in Superior to 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, for cash consideration of $300.0 million. Part of the proceeds from the sale were used to pay down our bank debt and the balance will be used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company, make additional capital investments in Superior, and for general working capital purposes.

Executive Summary

Oil and Natural Gas

Third quarter 2018 production from our oil and natural gas segment was 4,359,000 barrels of oil equivalent (Boe), an increase of 3% over the second quarter of 2018 and an increase of 7% over the third quarter of 2017, respectively. The increases for both comparative periods were primarily from new wells drilled during 2017 and the first nine months of 2018.

Third quarter 2018 oil and natural gas revenues increased 9% over the second quarter of 2018 and increased 31% over the third quarter of 2017. The increase over the second quarter of 2018 was due primarily to an increase in NGLs and natural gas production volumes and an increase in commodity prices partially offset by lower oil production volumes. The increase over the third quarter of 2017 was due primarily to higher oil and NGLs prices and higher production volumes.

Our oil prices for the third quarter of 2018 increased 2% over the second quarter of 2018 and increased 22% over the third quarter of 2017. Our NGLs prices increased 16% over the second quarter of 2018 and increased 40% over the third quarter of 2017. Our natural gas prices increased 4% over the second quarter of 2018 and decreased 4% from the third quarter of 2017.

Operating cost per Boe produced for the third quarter of 2018 decreased 4% from the second quarter of 2018 and decreased 12% from the third quarter of 2017. The decrease from the second quarter of 2018 was primarily due to lower lease operating expenses and increased equivalent production partially offset by increased gross production tax expense. The decrease from the third quarter of 2017 was primarily due to the reclassification of deducts from the ASC 606 revenue recognition standard.

Table of Contents

At September 30, 2018, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'18	Natural gas – swap	30,000 MMBtu/day	$3.005	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – swap	10,000 MMBtu/day	$2.810	IF – NYMEX (HH)
Oct'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.190)	NGPL TEXOK
Oct'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.678)	PEPL
Oct'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.568)	NGPL MIDCON
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jan'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
Oct'18 – Dec'18	Natural gas – three-way collar	20,000 MMBtu/day	$3.00 - $2.50 - $3.51	IF – NYMEX (HH)
Oct'18 – Dec'18	Crude oil – swap	4,000 Bbl/day	$53.52	WTI – NYMEX
Oct'18 – Dec'18	Crude oil – price differential risk	500 Bbl/day	$7.00	LLS/WTI
Oct'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Jan'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

After September 30, 2018, the following derivatives were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'19 – Dec'19	Natural gas – swap	10,000 MMBtu/day	$2.850	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Jan'19 – Mar'19	Natural gas – three-way collar	10,000 MMBtu/day	$3.00 - $2.75 - $4.35	IF – NYMEX (HH)

For the nine months ended September 30, 2018, we completed drilling 73 gross wells (21.06 net wells). For all of 2018, we anticipate participating in the drilling of approximately 95 to 105 gross wells. Excluding a reduction in ARO liability and any possible acquisitions, our estimated 2018 capital expenditures for this segment are approximately $333.0 million. Our current 2018 production guidance is approximately 17.1 to 17.3 MMBoe, an increase of 7-8% from 2017, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated in the third quarter of 2018 was 34.2 compared to 32.2 and 34.6 in the second quarter of 2018 and the third quarter of 2017, respectively. As of September 30, 2018, 34 of our drilling rigs were operating.

Revenue for the third quarter of 2018 increased 8% over the second quarter of 2018 and decreased 2% from the third quarter of 2017. The increase over the second quarter of 2018 was primarily due to increased utilization and dayrates. The decrease from the third quarter of 2017 was primarily due to increased eliminations with a large percentage of our drilling rig usage coming from our oil and gas segment in 2018 compared to 2017 partially offset by higher dayrates.

Dayrates for the third quarter of 2018 averaged $17,589, a 2% increase over the second quarter of 2018 and a 7% increase over the third quarter of 2017. The increase over the second quarter of 2018 was primarily due to general increases with the improving market and the addition of a BOSS drilling rig. The increase over the third quarter of 2017 was due to two labor increases passed through to contracted rigs rates and improving market dayrates.

Operating costs for the third quarter of 2018 were essentially unchanged from the second quarter of 2018 and decreased 8% from the third quarter of 2017. The decrease from the third quarter of 2017 was primarily due to increased eliminations with a larger percentage of our drilling rig usage coming from our oil and gas segment in 2018 and lower per day costs.

Table of Contents

Currently, we have 21 term drilling contracts with original terms ranging from six months to three years. Five are up for renewal in the fourth quarter of 2018, 13 in 2019, one in 2020, and two after 2020. The drilling rigs for the two expiring after 2020 are still under construction and will be placed into service in the first quarter of 2019. Term contracts may contain a fixed rate during the contract or provide for rate adjustments within a specific range from the existing rate.

All eleven of our existing BOSS drilling rigs are under contract. Our estimated 2018 capital expenditures for this segment are approximately $73.0 million.

Competition to keep qualified labor continues to be an issue we face in this segment and in response, we implemented pay rate increases in certain areas in the first quarter of 2018. We do not believe this shortage of qualified labor will keep us from working additional drilling rigs, but it could cause some delays in the time to crew new drilling rigs.

Mid-Stream

Third quarter 2018 liquids sold per day increased 4% over the second quarter of 2018 and increased 32% over the third quarter of 2017, respectively. The increase over the second quarter of 2018 was due to operating in higher recovery mode during the third quarter. The increase over the third quarter of 2017 was primarily due to increased volume available to process at our processing facilities due to additional well connects along with operating in higher recovery mode. For the third quarter of 2018, gas processed per day was essentially unchanged from the second quarter of 2018 and increased 14% over the third quarter of 2017. The increase over the third quarter of 2017 was primarily due to higher volumes from new wells connected to our processing facilities. For the third quarter of 2018, gas gathered per day increased 6% and 8% over the second quarter of 2018 and the third quarter of 2017, respectively. The increases over the second quarter of 2018 and the third quarter of 2017 were primarily due to connecting additional wells to our systems.

NGLs prices in the third quarter of 2018 increased 8% over the prices received in the second quarter of 2018 and increased 13% over the prices received in the third quarter of 2017. 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 third quarter of 2018 increased 9% over the second quarter of 2018 and increased 13% over the third quarter of 2017. The increase over the second quarter of 2018 was primarily due to higher gas and NGLs prices. The increase over the third quarter of 2017 was primarily due to higher purchased volumes and purchase prices.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for the third quarter of 2018 increased to approximately 142.6 MMcf per day after we added seven new infill wells late in the second quarter. All the new infill wells are currently online and flowing gas. We are completing construction of the new pipeline to connect the next scheduled well pad to our system. Construction of this pipeline is operationally complete and the improvements to the compressor station are expected to be completed early in the fourth quarter. We anticipate receiving production from this pad early in the first quarter of 2019.

At the Hemphill Texas system, average total throughput volume increased to 74.1 MMcf per day for the third quarter of 2018 and total production of NGLs increased to approximately 316,110 gallons per day. During the third quarter, we connected one new well in the Buffalo Wallow area. This new well along with increased production from recently drilled wells in this area contributed to our increased throughput volume. The increased liquid production was due to operating in ethane recovery mode. Unit Petroleum continues to operate a rig in the Buffalo Wallow area and we anticipate connecting additional wells to this system in the 4th quarter. Additionally, we have completed a construction project that increased our compression capacity at the Buffalo Wallow compressor station to accommodate expected additional volumes.

At the Cashion processing facility in central Oklahoma, total throughput volume for the second quarter of 2018 averaged approximately 47.5 MMcf per day and total production of NGLs increased to approximately 233,700 gallons per day. This system is operating at full processing capacity and we are in the process of adding additional capacity on this system. We have begun the relocation of a 60 MMcf per day processing plant from our Bellmon facility to the Cashion system. This $20.0 million plant expansion/relocation project is underway and will increase our total processing capacity to approximately 105 MMcf per day. This project is expected to be completed and operational in the first quarter of 2019. We connected eight new wells to this system in the third quarter of 2018 and we are continuing to connect additional wells from a third party producer who is active in this area.

Table of Contents

At the Segno gathering facility in Southeast Texas, gathered volume for the third quarter of 2018 averaged approximately 83.1 MMcf per day. At this facility, the existing gathering and dehydration capacity will allow us to gather up to 120 MMcf per day. In the third quarter of 2018, we added one new well to this system. Unit Petroleum is actively drilling in the Segno area, as well as, reworking and recompleting existing wells that are connected to our system which will continue to add additional volume.

Our estimated 2018 capital expenditures for this segment are approximately $50.0 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 twelve months. Our ability to meet our debt covenants (under our credit agreements and our 2011 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.

	Nine Months Ended September 30, 2018	2017	% Change
	(In thousands except percentages)		
Net cash provided by operating activities	$ 236,535	$ 184,792	28 %
Net cash used in investing activities	(279,507)	(204,184)	37 %
Net cash provided by financing activities	133,828	19,321	NM
Net increase (decrease) in cash and cash equivalents	$ 90,856	$ (71)	

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 nine months of 2018 increased by $51.7 million as compared to the first nine months of 2017. The increase resulted from increased operating profit in all three segments and a smaller decrease in changes in operating assets and liabilities related to the timing of cash receipts and disbursements partially offset by decreases in cash for derivatives settled.

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.

Table of Contents

Cash flows used in investing activities increased by $75.3 million for the first nine months of 2018 compared to the first nine months of 2017. 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 of cash spent on producing properties and other acquisitions. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $114.5 million for the first nine months of 2018 compared to the first nine months of 2017. The increase was primarily due to the proceeds from the sale of 50% interest in our mid-stream segment partially offset by the pay down of our outstanding debt under the Unit credit agreement.

At September 30, 2018, we had unrestricted cash and cash equivalents totaling $91.6 million and had not borrowed any of the $425.0 million or $200.0 million we had elected to have available under either of the Unit or Superior credit agreements, respectively. The credit agreements are used primarily for working capital and capital expenditures. On April 3, 2018, we paid down the outstanding debt under the Unit credit agreement.

Below, we summarize certain financial information as of September 30, 2018 and 2017 and for the nine months ended September 30, 2018 and 2017:

	September 30, 2018	September 30, 2017	% Change
	(In thousands except percentages)		
Working capital	$(15,959)	$(62,181)	74 %
Long-term debt less debt issuance costs	$643,921	$803,833	(20)%
Unit Corporation's shareholders’ equity	$1,467,737	$1,251,905	17 %
Net income attributable to Unit Corporation	$32,552	$28,693	13 %

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 $16.0 million and negative working capital of $62.2 million as of September 30, 2018 and 2017, respectively. The increase in working capital is primarily due to increased cash and cash equivalents from the sale of 50% interest in our mid-stream segment and increased accounts receivable due to increased revenues partially offset by increased accounts payable due to increased activity in our drilling program and increased drilling rig utilization and the change in the value of outstanding derivatives. The Unit and Superior credit agreements are used primarily for working capital and capital expenditures. At September 30, 2018, we had not borrowed any of the $425.0 million or the $200.0 million available under the Unit or Superior credit agreements, respectively. The effect of our derivative contracts decreased working capital by $13.1 million as of September 30, 2018 and increased working capital by $0.4 million as of September 30, 2017.

Table of Contents

This table summarizes certain operating information:

	Nine Months Ended September 30, 2018	2017	% Change
Oil and Natural Gas:			
Oil production (MBbls)	2,121	1,990	7 %
NGLs production (MBbls)	3,702	3,476	7 %
Natural gas production (MMcf)	41,572	37,317	11 %
Average oil price per barrel received	$56.40	$47.62	18 %
Average oil price per barrel received excluding derivatives	$65.89	$46.99	40 %
Average NGLs price per barrel received	$23.03	$17.05	35 %
Average NGLs price per barrel received excluding derivatives	$23.55	$17.05	38 %
Average natural gas price per Mcf received	$2.35	$2.50	(6)%
Average natural gas price per Mcf received excluding derivatives	$2.26	$2.55	(11)%
Contract Drilling:			
Average number of our drilling rigs in use during the period	32.7	29.7	10 %
Total number of drilling rigs owned at the end of the period	96	95	1 %
Average dayrate	$17,327	$16,120	7 %
Mid-Stream:			
Gas gathered—Mcf/day	393,414	385,846	2 %
Gas processed—Mcf/day	157,313	133,986	17 %
Gas liquids sold—gallons/day	651,979	518,054	26 %
Number of natural gas gathering systems	22 (1)	25	(12)%
Number of processing plants	14	13	8 %

(1) In the first quarter of 2018, our mid-stream segment transferred two natural gas gathering systems to our oil and natural gas segment.

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 nine months of 2018 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 $447,000 per month ($5.4 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 nine months of 2018 was $2.35 compared to $2.50 for the first nine months of 2017. Based on our first nine months of 2018 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $225,000 per month ($2.7 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 $398,000 per month ($4.8 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2018, our average oil price per barrel received, including the effect of derivatives, was $56.40 compared with an average oil price, including the effect of derivatives, of $47.62 in the first nine months of 2017 and our first nine months of 2018 average NGLs price per barrel received, including the effect of derivatives was $23.03 compared with an average NGLs price per barrel of $17.05 in the first nine months of 2017.

Because commodity prices affect the value of our oil, NGLs, and natural gas reserves, declines in those prices can cause a decline in the carrying value of our oil and natural gas properties. At September 30, 2018, the 12-month average unescalated prices were $63.43 per barrel of oil, $38.69 per barrel of NGLs, and $2.91 per Mcf of natural gas, and then are adjusted for price differentials. We did not take a write down in the first nine months of 2018.

Table of Contents

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 September 30, 2018, and only adjust the 12-month average price to an estimated fourth quarter ending average (holding October 2018 prices constant for the remaining two months of the fourth quarter of 2018), our forward looking expectation is that we will not recognize an impairment in the fourth quarter of 2018. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for a future impairment.

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 nine months of 2018, our average dayrate was $17,327 per day compared to $16,120 per day for the first nine months of 2017. The average number of our drilling rigs used in the first nine months of 2018 was 32.7 drilling rigs compared with 29.7 drilling rigs in the first nine months of 2017. Based on the average utilization of our drilling rigs during the first nine months of 2018, a $100 per day change in dayrates has a $3,270 per day ($1.2 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 $18.0 million and $9.6 million for the first nine months of 2018 and 2017, respectively, from our contract drilling segment and eliminated the associated operating expense of $15.5 million and $8.6 million during the first nine months of 2018 and 2017, respectively, yielding $2.4 million and $1.0 million during the first nine months of 2018 and 2017, 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, 14 processing plants, 22 gathering systems, and approximately 1,470 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 nine months of 2018 and 2017, our mid-stream operations purchased $59.8 million and $43.2 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $5.2 million and $4.9 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 393,414 Mcf per day in the first nine months of 2018 compared to 385,846 Mcf per day in the first nine months of 2017. It processed an average of 157,313 Mcf per day in the first nine months of 2018 compared to 133,986 Mcf per day in the first nine months of 2017. The NGLs sold was 651,979 gallons per day in the first nine months of 2018 compared to 518,054 gallons per day in the first nine months of 2017. Gas gathered volumes per day in the first nine months of 2018 increased 2% compared to the first nine months of 2017 primarily due to connecting additional wells to our Cashion and Hemphill facilities. Gas processed volumes for the first nine months of 2018 increased 17% over the first nine months of 2017 due to connecting new wells at the Cashion and Hemphill processing facilities. NGLs sold increased 26% over the comparative period due to higher volume available to process at our plants along with operating in higher recovery mode.

Table of Contents

At-the-Market (ATM) Common Stock Program

On May 2, 2018, we terminated the Distribution Agreement dated April 4, 2017, as amended (the Distribution Agreement), between the company and Raymond James & Associates, Inc. (the Sales Agent). The Distribution Agreement was terminable at will on written notification by the company with no penalty. Under the Distribution Agreement, the company was entitled to issue and sell, from time to time, through or to the Sales Agent shares of its common stock, having an aggregate offering price of up to $100.0 million in an "at-the-market" offering program. As of the date of termination, the company sold 787,547 shares of its Common Stock under the Distribution Agreement. As a result of the termination, there will be no more sales of the our common stock under the Distribution Agreement.

Our Credit Agreements and Senior Subordinated Notes

Unit Credit Agreement. On October 18, 2018, we signed the fifth amendment to the Unit credit agreement originally scheduled to mature on April 10, 2020 (Fifth Amendment). The Fifth Amendment amends our existing credit agreement entered into between the Company and certain lenders on September 13, 2011, as amended September 12, 2012, as further amended April 10, 2015, as further amended on April 8, 2016, as further amended on April 2, 2018, attached as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 15, 2011, September 11, 2012, April 13, 2015, April 8, 2016, and April 6, 2018, respectively, and the Company's Current Report on Form 8-K/A filed on April 13, 2016, and each incorporated by reference herein.

The Fifth Amendment, among other things, (i) extends the term of the Unit credit agreement to October 18, 2023, subject to certain conditions; (ii) reduces the pricing for borrowing and non-use fees; and (iii) eliminates the requirement that the company maintain a senior indebtedness to consolidated EBITDA ratio. The total commitment of credit and the borrowing base both remain unchanged at $425.0 million.

Under the Unit credit agreement, the amount we can borrow is the lesser of the amount we elect as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement. We are charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. Total amendment fees of $3.3 million in origination, agency, syndication, and other related fees are being amortized over the life of the Unit credit agreement. Under the Unit credit agreement, we have pledged as collateral 80% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties.

On April 2, 2018, we signed the fourth amendment to the Unit credit agreement. The Fourth Amendment provided, among other things, for a reduction of the maximum credit amount from $875.0 million to $425.0 million, a reduction in the borrowing base from $475.0 million to $425.0 million, a reduction in the total commitment amount from $475.0 million to $425.0 million; and the full release of Superior and its subsidiaries as a borrower and co-obligor under the Unit credit agreement. Under the amendment once the sale of the interest in Superior was completed, we were required to us part of the proceeds to pay down the Unit credit agreement. The Superior sale closed on April 3, 2018 and the pay down was made that day.

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

Table of Contents

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 could 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 that cannot be less than LIBOR plus 1.00% plus a margin. 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 September 30, 2018, we did not have any outstanding borrowings. The outstanding balance was paid down on April 3, 2018.

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

The Unit credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year over 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions;
-

the creation or existence of mortgages or liens, other than those in the ordinary course of business and with certain limited exceptions, on any of our properties, except in favor of our lenders;

- investments in Unrestricted Subsidiaries in excess of $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 September 30, 2018, we were in compliance with the Unit credit agreement 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

55

Table of Contents

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.

Superior is charged a commitment fee of 0.375% on the amount available but not borrowed which varies based on the amount borrowed as a percentage of the total borrowing base. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio of not greater than 4.00 to 1.00. Additionally, the Superior credit agreement contains a number of customary covenants that, among other things, restrict (subject to certain exceptions) Superior's ability to incur additional indebtedness, create additional liens on its assets, make investments, pay distributions, enter into sale and leaseback transactions, engage in certain transactions with affiliates, engage in mergers or consolidations, enter into hedging arrangements, and acquire or dispose of assets. As of September 30, 2018, 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.

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.

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. Any of our 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 September 30, 2018.

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 73 gross wells (21.06 net wells) in the first nine months of 2018 compared to 43 gross wells (15.10 net wells) in the first nine months of 2017.

Capital expenditures for oil and gas properties on the full cost method for the first nine months of 2018 by this segment, excluding $0.8 million for acquisitions and a $8.5 million reduction in the ARO liability, totaled $259.4 million. Capital expenditures for the first nine months of 2017, excluding $56.4 million for acquisitions and a $2.8 million reduction in the ARO liability, totaled $143.7 million.

We anticipate participating in drilling approximately 95 to 105 gross wells in 2018 and our total estimated capital expenditures (excluding a reduction in ARO liability and any possible acquisitions) for this segment are approximately $333.0 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 mid-July. During the second quarter and third quarter of 2018, we were awarded term contracts to build our 12th and 13th BOSS drilling rigs. Construction is in progress and the drilling rigs will be placed into service in the first quarter of 2019.

Our estimated 2018 capital expenditures for this segment are approximately $73.0 million. At September 30, 2018, we had commitments to purchase approximately $10.1 million for drilling equipment over the next year. We have spent $46.5 million for capital expenditures during the first nine months of 2018, compared to $30.0 million for capital expenditures during the first nine months of 2017.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for the third quarter of 2018 increased to approximately 142.6 MMcf per day after we added seven new infill wells late in the second quarter. All the new infill wells are currently online and flowing gas. We are completing construction of the new pipeline to connect the next scheduled well pad to our system. Construction of this pipeline is operationally complete and the improvements to the compressor station are expected to be completed early in the fourth quarter. We anticipate receiving production from this pad early in the first quarter of 2019.

At the Hemphill Texas system, average total throughput volume increased to 74.1 MMcf per day for the third quarter of 2018 and total production of NGLs increased to approximately 316,110 gallons per day. During the third quarter, we connected one new well in the Buffalo Wallow area. This new well along with increased production from recently drilled wells in this area contributed to our increased throughput volume. The increased liquid production was due to operating in ethane recovery mode. Unit Petroleum continues to operate a rig in the Buffalo Wallow area and we anticipate connecting additional wells to this system in the 4th quarter. Additionally, we have completed a construction project that increased our compression capacity at the Buffalo Wallow compressor station to accommodate expected additional volumes.

Table of Contents

At the Cashion processing facility in central Oklahoma, total throughput volume for the second quarter of 2018 averaged approximately 47.5 MMcf per day and total production of NGLs increased to approximately 233,700 gallons per day. This system is operating at full processing capacity and we are in the process of adding additional capacity on this system. We have begun the relocation of a 60 MMcf per day processing plant from our Bellmon facility to the Cashion system. This $20.0 million plant expansion/relocation project is underway and will increase our total processing capacity to approximately 105 MMcf per day. This project is expected to be completed and operational in the first quarter of 2019. We connected eight new wells to this system in the third quarter of 2018 and we are continuing to connect additional wells from a third party producer who is active in this area.

At the Segno gathering facility in Southeast Texas, gathered volume for the third quarter of 2018 averaged approximately 83.1 MMcf per day. At this facility, the existing gathering and dehydration capacity will allow us to gather up to 120 MMcf per day. In the third quarter of 2018, we added one new well to this system. Unit Petroleum is actively drilling in the Segno area, as well as, reworking and recompleting existing wells that are connected to our system which will continue to add additional volume.

On April 3, 2018, the company completed the sale of 50% of the ownership interests in Superior to 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, for cash consideration of $300.0 million.

During the first nine months of 2018, our mid-stream segment incurred $29.0 million in capital expenditures as compared to $10.1 million in the first nine months of 2017. For 2018, our estimated capital expenditures are approximately $50.0 million.

Contractual Commitments

At September 30, 2018, 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)]	$762,906	$43,063	$719,843	$ —	$ —
Operating leases [(2)]	7,967	5,144	2,798	25	—
Capital lease interest and maintenance[(3)]	5,357	2,234	3,123	—	—
Drill pipe, drilling components, and equipment purchases [(4)]	10,064	10,064	—	—	—
Total contractual obligations	$786,294	$60,505	$725,764	$ 25	$ —

(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 September 30, 2018 interest rates of 6.625% for the Notes. At September 30, 2018, our credit agreement had a maturity date of April 10, 2020. The outstanding credit facility balance was paid down on April 3, 2018 and as of September 30, 2018, we did not have any outstanding borrowings.

(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)

Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are $4.6 million and $0.8 million, respectively.

(4) We have committed to pay $10.1 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.

Table of Contents

At September 30, 2018, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period				
	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan [(1)]	$5,623	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [(2)]	$8,135	$ 966	Unknown	Unknown	Unknown
Asset retirement liability [(3)]	$62,727	$ 1,451	$ 36,308	$ 3,747	$ 21,221
Gas balancing liability [(4)]	$3,283	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [(5)]	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability[(6)]	$12,832	$ 4,897	$ 2,501	$ 1,067	$ 4,367
Capital leases obligations [(7)]	$12,355	$ 3,961	$ 8,394	$ —	$ —
Contract liability [(8)]	$10,605	$ 2,875	$ 5,654	$ 2,076	$ —

(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 made repurchases of approximately $1,700 and $2,900 in the first nine months of 2018 and 2017, respectively.

(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 capital 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.

Table of Contents

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 September 30, 2018, based on our third quarter 2018 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	2018 Q4	2019
Daily oil production	80 %	53 %
Daily natural gas production	28 %	13 %

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 September 30, 2018 evaluation, we believe the risk of non-performance by our counterparties is not material. At September 30, 2018, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	September 30, 2018 (In millions)
Canadian Imperial Bank of Commerce	$ —
Bank of America	(2.2)
Bank of Montreal	(12.4)
Total liabilities	$ (14.6)

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 September 30, 2018, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of $13.1 million and $1.5 million, respectively. At December 31, 2017, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.7 million and current derivative liabilities of $7.8 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 Income Statements. These gains (losses) at September 30 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Gain (loss) on derivatives:				
Gain (loss) on derivatives, included are amounts settled during the period of ($9,112), $840, ($18,040) and ($729), respectively	$(4,385)	$(2,614)	$(25,608)	$21,019
	$(4,385)	$(2,614)	$(25,608)	$21,019

Stock and Incentive Compensation

During the first nine months of 2018, we granted awards covering 1,250,880 shares of restricted stock. These awards had an estimated fair value as of their grant date of $24.4 million. Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2018, we recognized $6.6 million in compensation expense and capitalized $1.0 million for these awards. During the first nine months of 2018, we recognized compensation expense of $13.6 million for all of our restricted stock and capitalized $1.6 million of compensation cost for oil and natural gas properties.

During the first nine months of 2017, we granted awards covering 698,276 shares of restricted stock. These awards had an estimated fair value as of their grant date of $17.2 million. Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2017, we recognized $5.0 million in compensation expense and capitalized $0.8 million for these awards. During the first nine months of 2017, we recognized compensation expense of $9.0 million for all of our restricted stock, stock options, and SAR grants and capitalized $1.3 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from zero to $1.0 million. We have purchased stop-loss coverage 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

We are the general partner of 13 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision, and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. For the first nine months of 2018 and 2017, the total we received for all of these fees was $0.1 million in each period. Our proportionate share of assets, liabilities, and net income relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

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.

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 the scope of 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, 2019, and interim periods within those years. This amendment will not have a material impact on our financial statements.

Income Taxes - Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118. In March 2018, the FASB issued ASU 2018-05 which updates the FASB's Accounting Standards Codification to reflect the guidance in SAB 118, which adds Section EE, "Income Tax Accounting Implications of the Tax Cuts and Jobs Act," to SAB Topic 5, "Miscellaneous Accounting." SAB 118 also provides guidance on applying ASC 740, Income Taxes, if the accounting for certain income tax effects of the Tax Cuts and Jobs Act of 2017 is incomplete when the financial statements are issued for a reporting period.

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.

Leases. The FASB has issued several accounting standards updates and amendments related to leases in the past two years, which are codified within Topic 842. For public companies, these are effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. The standard requires lessees to recognize at the commencement date of a lease a lease liability, which represents the lessee's obligation to make lease payments arising from the lease, measured on a discounted basis; and a right-of-use asset, which represents the lessee's right to use a specified asset for the lease term. Other recently issued amendments to Topic 842 have provided clarifying guidance regarding land easements, an

Table of Contents

additional modified retrospective transition method, and added several practical expedients to apply Topic 842 for both lessees and lessors. The standard will not apply to leases of mineral rights.

We have an implementation team working through the provisions of the new guidance including a review of different types of contracts to document our lease portfolio and assess the impact on our accounting, disclosures, processes, internal control over financial reporting, and the election of certain practical expedients. Our evaluation of the impact of the new guidance on our financial statements is on-going.

We have made certain accounting policy decisions including that we plan to adopt the short-term lease recognition exemption, accounting for certain asset classes at a portfolio level, and establishing a balance sheet recognition capitalization threshold. Our transition will utilize the modified retrospective approach to adopting the new standard, and will be applied at the beginning of the period adopted (January 1, 2019) in accordance with ASU 2018-11. We expect to elect the transition practical expedient, which allows us to not evaluate land easements that existed prior to January 1, 2019, and the optional transition method to record the adoption impact through a cumulative adjustment to equity. We expect for certain lessee asset classes to elect the practical expedient and not separate lease and nonlease components. For these asset classes, we will account for the agreements as a single lease component.

We expect for certain lessor asset classes to elect the practical expedient and not separate lease and nonlease components and determine the appropriate accounting based on the predominate component of the contract. The assessment of predominance is ongoing.

We anticipate a material impact to the balance sheet across segments as we recognize Right of Use assets and liabilities but no material impact to the income statement (from the lessee's perspective). The assessment of the dollar value impact of adoption is on-going.

Adopted Standards

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. The FASB issued ASU 2018-02, an amendment which provides financial statement preparers with an option to reclassify stranded tax effects within AOCI to retained earnings caused by the Tax Cuts and Jobs Act of 2017. The amendment is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. Organizations should apply the proposed amendments either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Tax Cuts and Jobs Act is recognized. We adopted this amendment early and it had no material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and now we are using 24.5%. The change is reflected in our Unaudited Condensed Consolidated Statements of Comprehensive Income and in Note 14 - Equity.

Revenue from Contracts with Customers. Effective January 1, 2018, we adopted ASC 606. This new revenue standard provides for a five-step analysis of transactions to determine when and how revenue is to be recognized. The guidance in this update supersedes the revenue recognition requirements in ASC 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Under the standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. We applied the five step method outlined in the ASU to all of our revenue streams in the scope of ASC 606 and elected the modified retrospective approach method. Under that approach the cumulative effect on adoption is recognized as an adjustment to opening retained earnings at January 1, 2018. Only our mid-stream segment was affected. This adjustment related to the timing of revenue on certain demand fees. Both our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by ASC 606 have been included in Note 2 – Revenue from Contracts with Customers.

Our internal control framework did not materially change as a result of this standard, but the existing internal controls have been modified to consider our new revenue recognition policy effective January 1, 2018. As we implement the new standard, we have added internal controls to ensure that we adequately evaluate new contracts under the five-step model under ASU 2014-09.

Table of Contents

Results of Operations

Quarter Ended September 30, 2018 versus Quarter Ended September 30, 2017

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

	Quarter Ended September 30, 2018	2017	Percent Change [(1)]
	(In thousands unless otherwise specified)		
Total revenue	$220,058	$188,488	17 %
Net income	$21,123	$3,705	NM
Net income attributable to non-controlling interest	$2,224	$—	— %
Net income attributable to Unit Corporation	$18,899	$3,705	NM
Oil and Natural Gas:			
Revenue	$111,623	$85,470	31 %
Operating costs excluding depreciation, depletion, and amortization	$32,139	$33,911	(5)%
Depreciation, depletion, and amortization	$35,460	$26,460	34 %
Average oil price received (Bbl)	$57.72	$47.29	22 %
Average NGLs price received (Bbl)	$25.66	$18.35	40 %
Average natural gas price received (Mcf)	$2.27	$2.36	(4)%
Oil production (Bbl)	692,000	633,000	9 %
NGLs production (Bbl)	1,278,000	1,243,000	3 %
Natural gas production (Mcf)	14,336,000	13,085,000	10 %
Depreciation, depletion, and amortization rate (Boe)	$7.56	$6.18	22 %
Contract Drilling:			
Revenue	$50,612	$51,619	(2)%
Operating costs excluding depreciation	$32,032	$34,747	(8)%
Depreciation	$14,889	$15,280	(3)%
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	34.2	34.6	(1)%
Average dayrate on daywork contracts	$17,589	$16,454	7 %
Mid-Stream:			
Revenue	$57,823	$51,399	12 %
Operating costs excluding depreciation and amortization	$43,134	$38,116	13 %
Depreciation and amortization	$11,265	$10,880	4 %
Gas gathered—Mcf/day	415,862	383,787	8 %
Gas processed—Mcf/day	160,294	140,246	14 %
Gas liquids sold—gallons/day	700,523	530,028	32 %
Corporate and other:			
General and administrative expense	$9,278	$9,235	— %
Other depreciation	$1,923	$1,913	1 %
Gain on disposition of assets	$253	$81	NM
Other income (expense):			

Interest income	$385	$—	— %
Interest expense, net	$(8,330)	$(9,944)	(16)%
Loss on derivatives	$(4,385)	$(2,614)	68 %
Other	$6	$5	20 %
Income tax expense	$6,744	$1,769	NM
Average long-term debt outstanding	$635,870	$804,617	(21)%
Average interest rate	6.7 %	6.0 %	12 %

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

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues increased $26.2 million or 31% in the third quarter of 2018 as compared to the third quarter of 2017 primarily due to higher oil and NGLs prices and higher production volumes partially offset by lower gas prices. In the third quarter of 2018, as compared to the third quarter of 2017, oil production increased 9%, natural gas production increased 10%, and NGLs production increased 3%. Average oil prices increased 22% to $57.72 per barrel, average natural gas prices decreased 4% to $2.27 per Mcf, and NGLs prices increased 40% to $25.66 per barrel.

Oil and natural gas operating costs decreased $1.8 million or 5% between the comparative third quarters of 2018 and 2017 due to the impact of the ASC 606 Revenue Recognition classification of certain deducts partially offset by higher gross production taxes.

Depreciation, depletion, and amortization (DD&A) increased $9.0 million or 34% due primarily to a 22% increase in the DD&A rate and an 7% increase in equivalent production. The increase in our DD&A rate in the third quarter of 2018 compared to the third quarter of 2017 resulted primarily from the cost of wells drilled in the last three months of 2017 and the first nine months of 2018.

Contract Drilling

Drilling revenues decreased $1.0 million or 2% in the third quarter of 2018 versus the third quarter of 2017. The decrease was due primarily to an 1% decrease in the average number of drilling rigs in use and an increase in eliminations with an increase percentage of our drilling rigs being used by our oil and gas segment partially offset by a 7% increase in the average dayrate. Average drilling rig utilization decreased from 34.6 drilling rigs in the third quarter of 2017 to 34.2 drilling rigs in the third quarter of 2018.

Drilling operating costs decreased $2.7 million or 8% between the comparative third quarters of 2018 and 2017. The decrease was due primarily to less drilling rigs operating partially offset by increase in per day operating expense. Contract drilling depreciation decreased $0.4 million or 3% in the third quarter of 2018 versus the third quarter of 2017 also due to less drilling rigs operating.

Mid-Stream

Our mid-stream revenues increased $6.4 million or 12% in the third quarter of 2018 as compared to the third quarter of 2017 due primarily to higher volumes and increases in NGL and condensate prices partially offset by decreased natural gas prices. Gas processed volumes per day increased 14% between the comparative quarters primarily due to additional wells connected to our processing systems. Gas gathered volumes per day increased 8% between the comparative quarters primarily due to connecting new wells to our systems.

Operating costs increased $5.0 million or 13% in the third quarter of 2018 compared to the third quarter of 2017 primarily due to higher gas purchase volumes and higher field direct and general and administrative expenses due to increased employee cost and from a $250,000 monthly service fee for outside services. Depreciation and amortization increased $0.4 million, or 4%, primarily due to new capital assets placed in service.

Gain on Disposition of Assets

There was a $0.3 million gain on disposition of assets in the third quarter of 2018 primarily due to the sale of drilling rig components and vehicles, compared to a gain of $0.1 million for the disposition of assets in the third quarter of 2017 primarily due to the sale of vehicles.

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $1.6 million between the comparative third quarters of 2018 and 2017 due primarily to a 21% decrease in average long-term debt outstanding in the third quarter of 2018 and increased interest capitalized partially offset by a higher average interest rate. We had interest earned of $0.4 million from the cash in our investment account from the excess proceeds from the sale of 50% of Superior. 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 third quarter of 2018 was $4.2 million compared to $4.0 million in the third quarter of 2017, and was netted against our gross interest of $12.5 million and $14.0 million for the third quarters of 2018 and 2017, respectively. Our average interest rate increased from 6.0% in the third quarter of 2017 to 6.7% in

Table of Contents

the third quarter of 2018 and our average debt outstanding was $168.7 million lower in the third quarter of 2018 as compared to the third quarter of 2017 primarily due to the pay down of the Unit credit agreement in the second quarter of 2018.

Loss on Derivatives

Loss on derivatives increased $1.8 million primarily due to losses on derivatives settled partially offset by a gain from fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense increased $5.0 million between the comparative third quarters of 2018 and 2017 primarily due to increased pre-tax income but was tempered to a certain degree by our lower statutory tax rate due to the 2017 Tax Act, and elimination of non-controlling interest income. Our effective tax rate was 24.2% for the third quarter of 2018 compared to 32.3% for the second quarter of 2017. The rate change was again primarily due to the lower federal statutory tax rate due to the 2017 Tax Act and elimination of non-controlling interest income. There was no current income tax expense in the third quarter of 2018 or 2017. We paid $3.6 million in income taxes in the third quarter of 2018 related to our sale of 50% of Superior. 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 have been recorded to Capital in excess of par value.

Table of Contents

Nine Months Ended September 30, 2018 versus Nine Months Ended September 30, 2017
Provided below is a comparison of selected operating and financial data:

	Nine Months Ended September 30, 2018	2017	Percent Change
	(In thousands unless otherwise specified)		
Total revenue	$628,493	$534,793	18 %
Net income	$37,138	$28,693	29 %
Net income attributable to non-controlling interest	$4,586	$—	— %
Net income attributable to Unit Corporation	$32,552	$28,693	13 %
Oil and Natural Gas:			
Revenue	$317,040	$256,241	24 %
Operating costs excluding depreciation, depletion, and amortization	$100,519	$95,873	5 %
Depreciation, depletion, and amortization	$97,797	$71,544	37 %
Average oil price received (Bbl)	$56.40	$47.62	18 %
Average NGLs price received (Bbl)	$23.03	$17.05	35 %
Average natural gas price received (Mcf)	$2.35	$2.50	(6)%
Oil production (Bbl)	2,121,000	1,990,000	7 %
NGLs production (Bbl)	3,702,000	3,476,000	7 %
Natural gas production (Mcf)	41,572,000	37,317,000	11 %
Depreciation, depletion, and amortization rate (Boe)	$7.32	$5.76	27 %
Contract Drilling:			
Revenue	$143,527	$128,059	12 %
Operating costs excluding depreciation	$95,593	$91,213	5 %
Depreciation	$41,927	$41,896	— %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	32.7	29.7	10 %
Average dayrate on daywork contracts	$17,327	$16,120	7 %
Mid-Stream:			
Revenue	$167,926	$150,493	12 %
Operating costs excluding depreciation and amortization	$124,441	$111,862	11 %
Depreciation and amortization	$33,493	$32,547	3 %
Gas gathered—Mcf/day	393,414	385,846	2 %
Gas processed—Mcf/day	157,313	133,986	17 %
Gas liquids sold—gallons/day	651,979	518,054	26 %
Corporate and other:			
General and administrative expense	$28,752	$26,902	7 %
Other depreciation	$5,759	$5,558	4 %
Gain on disposition of assets	$575	$1,153	(50)%
Other income (expense):			
Interest income	$796	$—	— %

Interest expense, net	$(26,474)	$(28,807)	(8)%
Gain (loss) on derivatives	$(25,608)	$21,019	NM
Other	$17	$14	21 %
Income tax expense	$12,380	$22,084	(44)%
Average long-term debt outstanding	$700,378	$811,159	(14)%
Average interest rate	6.5 %	6.0 %	8 %

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

66

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues increased $60.8 million or 24% in the first nine months 2018 as compared to the first nine months of 2017 primarily due to higher oil and NGLs prices and higher production volumes. In the first nine months of 2018, as compared to the first nine months of 2017, oil production increased 7%, natural gas production increased 11%, and NGLs production increased 7%. Average oil prices increased 18% to $56.40 per barrel, average natural gas prices decreased 6% to $2.35 per Mcf, and NGLs prices increased 35% to $23.03 per barrel.

Oil and natural gas operating costs increased $4.6 million or 5% between the comparative first nine months of 2018 and 2017 due to higher LOE, saltwater disposal, and gross production tax partially offset by the impact of the change in classification of certain deducts due to the implementation on January 1, 2018 of ASC 606 Revenue Recognition reclass.

DD&A increased $26.3 million or 37% due primarily to a 27% increase in our DD&A rate and a 9% increase in equivalent production. The increase in our DD&A rate in the first nine months of 2018 compared to the first nine months of 2017 resulted primarily from the cost of wells drilled in the last three months of 2017 and the first nine months of 2018.

Contract Drilling

Drilling revenues increased $15.5 million or 12% in the first nine months of 2018 versus the first nine months of 2017. The increase was due primarily to a 10% increase in the average number of drilling rigs in use and an a 7% increase in the average dayrate along with increased revenues from mobilizations. Average drilling rig utilization increased from 29.7 drilling rigs in the first nine months of 2017 to 32.7 drilling rigs in the first nine months of 2018.

Drilling operating costs increased $4.4 million or 5% between the comparative first nine months of 2018 and 2017. The increase was due primarily to more drilling rigs operating. Contract drilling depreciation was essentially unchanged.

Mid-Stream

Our mid-stream revenues increased $17.4 million or 12% in the first nine months of 2018 as compared to the first nine months of 2017 due primarily to an increase in NGLs and condensate prices and volumes along with an increase in gas volumes sold partially offset by a decrease in natural gas prices. Gas processed volumes per day increased 17% between the comparative periods primarily due to connecting new wells at the Cashion and Hemphill processing facilities. Gas gathered volumes per day increased 2% between the comparative periods primarily due to connecting new wells at the Cashion and Hemphill facilities partially offset by declines in volumes in the Appalachian area.

Operating costs increased $12.6 million or 11% in the first nine months of 2018 compared to the first nine months of 2017 primarily due to increased purchase volumes along with higher field direct and general and administrative expenses due to increased employee cost and from a $250,000 monthly outside service fee incurred in the second quarter. Depreciation and amortization increased $0.9 million, or 3%, primarily due to new capital assets placed into service.

Other Depreciation

Other depreciation increased 4% during the first nine months of 2018 compared to the first nine months of 2017 due primarily to the ERP accounting and reporting system that was implemented during the first quarter of 2017.

General and Administrative

Corporate general and administrative expenses increased $1.9 million or 7% in the first nine months of 2018 compared to the first nine months of 2017 primarily due to higher employee costs.

Gain on Disposition of Assets

There was an $0.6 million gain on disposition of assets in the first nine months of 2018 primarily due to the sale of drilling rig components and vehicles, compared to a gain of $1.2 million for the disposition of assets in the first nine months of 2017 primarily due to the sale of a corporate aircraft and vehicles.

Table of Contents

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $2.3 million between the comparative first nine months of 2018 and 2017 due primarily to a 14% decrease in the average long-term debt outstanding and an increase in interest capitalized partially offset by a higher average interest rate. We had interest earned of $0.8 million from the excess cash in our investment account from the sale of 50% of Superior. 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 nine months of 2018 was $12.1 million compared to $11.9 million in the first nine months of 2017, and was netted against our gross interest of $38.6 million and $40.7 million for the first nine months of 2018 and 2017, respectively. Our average interest rate increased from 6.0% to 6.5% and our average debt outstanding was $110.8 million lower in the first nine months of 2018 as compared to the first nine months of 2017 primarily due to the pay down of our Unit credit agreement in the second quarter of 2018.

Gain (Loss) on Derivatives

Gain (loss) on derivatives decreased $46.6 million primarily due to increased losses on derivaties settled along with losses on unrealized hedges compared to gains on unrealized value in 2017.

Income Tax Expense

Income tax expense decreased $9.7 million between the comparative first nine months of 2018 and 2017 primarily due to decreased pre-tax income, lower statutory tax rate due to the 2017 Tax Act, and elimination of non-controlling interest income. Our effective tax rate was 25.0% for the first nine months of 2018 compared to 43.5% for the first nine months of 2017. The decrease was again primarily due to the lower federal statutory tax rate due to the 2017 Tax Act, elimination of non-controlling interest income, and to a lesser extent, smaller deferred income tax expense related to our restricted stock vestings in the first nine months of 2018 as compared to the first nine months of 2017. There was no current income tax expense in the first nine months of 2018 or 2017. We paid $3.6 million in income taxes in the first nine months of 2018 related to the our sale of 50% of Superior. 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 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;

Table of Contents

- 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;
- 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.

Table of Contents

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 nine months 2018 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 $447,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $225,000 per month ($2.7 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 $398,000 per month ($4.8 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 production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At September 30, 2018, these derivatives were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'18	Natural gas – swap	30,000 MMBtu/day	$3.005	IF – NYMEX (HH)
Nov’18 – Dec'18	Natural gas – swap	20,000 MMBtu/day	$3.013	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – swap	10,000 MMBtu/day	$2.810	IF – NYMEX (HH)
Oct'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.190)	NGPL TEXOK
Oct'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.678)	PEPL
Oct'18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.568)	NGPL MIDCON
Nov’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGL MIDCON
Jan'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
Oct'18 – Dec'18	Natural gas – three-way collar	20,000 MMBtu/day	$3.00 - $2.50 - $3.51	IF – NYMEX (HH)
Oct'18 – Dec'18	Crude oil – swap	4,000 Bbl/day	$53.52	WTI – NYMEX
Oct'18 – Dec'18	Crude oil – price differential risk	500 Bbl/day	$7.00	LLS/WTI
Oct'18 – Dec'18	Crude oil – three-way collar	2,000 Bbl/day	$47.50 - $37.50 - $56.08	WTI – NYMEX
Jan'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

After September 30, 2018, the following derivatives were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'19 – Dec'19	Natural gas – swap	10,000 MMBtu/day	$2.850	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX

				(HH)
Jan'19 – Mar'19	Natural gas – three-way collar	10,000 MMBtu/day	\$3.00 - \$2.75 - \$4.35	IF – NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreements and the Notes. The credit 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. As of October 19, 2018,

Table of Contents

we did not have any outstanding debt under our credit agreements. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) (Disclosure Controls) or our internal control over financial reporting (ICFR) 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 control. The design of any system of controls also is based in part on certain assumptions about the likelihood of future events, and there is no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to an error or fraud may occur and not be detected. We monitor our Disclosure Controls and ICFR and make modifications as necessary; our intent in this regard is that the Disclosure Controls and ICFR will be modified as systems change, and conditions warrant.

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of the design and operation of our Disclosure Controls under the Exchange Act in ensuring the information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the CEO, CFO, and management as appropriate to allow timely decisions regarding required disclosure.

Based on that evaluation, our CEO and CFO concluded that our Disclosure Controls were not effective as of September 30, 2018 due to a material weakness in ICFR described below.

Material Weakness in Internal Control Over Financial Reporting. 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 our 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. This control deficiency led to a misstatement that resulted in the revision of our statement of cash flows for the year ended December 31, 2017, and the restatement of our statement of cash flows for the interim period ended March 31, 2018. This material weakness could result in misstatements of the annual or interim consolidated financial statements or disclosures that would not be prevented or detected.

Plan for Remediation of the Material Weakness. We have 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; and
- provided additional training to financial reporting personnel with respect to the preparation and review of the consolidated financial statements.

Management believes the measures described above will remediate the material weakness that we have identified. 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 controls over financial reporting, we may decide to take additional measures to address this control deficiency or determine to modify certain of the remediation measures.

Table of Contents

Changes in Internal Controls. There were no other changes in our internal control over financial reporting (ICFR) during the quarter ended September 30, 2018, that materially affected our ICFR or are reasonably likely to materially affect it, as defined in Rule 13a – 15(f) under the Exchange Act.

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.

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.

Table of Contents

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, 2017, 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, 2017.

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 September 30, 2018:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(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
July 1, 2018 to July 31, 2018	—	$ —	—	—
August 1, 2018 to August 31, 2018	—	—	—	—
September 1, 2018 to September 30, 2018	—	—	—	—
Total	—	$ —	—	—

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Table of Contents

Item 6. Exhibits

Exhibits:

10.1	Fifth Amendment to Senior Credit Agreement dated October 18, 2018 (filed herewith).
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.

*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.

Table of Contents

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:	November 6, 2018	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date:	November 6, 2018	By: /s/ Les Austin LES AUSTIN Senior Vice President and Chief Financial Officer