

UNIT CORP
Form 10-Q
May 05, 2016
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended March 31, 2016

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.)

7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136

(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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files).

Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

As of April 22, 2016, 51,421,780 shares of the issuer's common stock were outstanding.

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Forward-Looking Statements

This report contains “forward-looking statements” – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document that addresses activities, events or developments we expect or anticipate will or may occur in the future, 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 in the future 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;
- the number of wells we plan to drill or rework;
- 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 our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil 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;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may be required to record in future periods.

These statements are based on assumptions and analyses made by us in light of 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;
- decreases or increases in commodity prices; and

Other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current 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 document to reflect unanticipated events.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2016	December 31, 2015
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 739	\$ 835
Accounts receivable, net of allowance for doubtful accounts of \$5,199 at both March 31, 2016 and December 31, 2015, respectively	68,424	79,941
Materials and supplies	3,303	3,565
Current derivative asset (Note 10)	13,901	10,186
Current income tax receivable	20,652	21,002
Current deferred tax asset	8,598	14,206
Assets held for sale	225	615
Prepaid expenses and other	8,250	9,908
Total current assets	124,092	140,258
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,387,103	5,401,618
Unproved properties not being amortized	330,274	337,099
Drilling equipment	1,569,740	1,567,560
Gas gathering and processing equipment	691,759	689,063
Saltwater disposal systems	60,459	60,316
Corporate land and building	55,077	49,890
Transportation equipment	38,659	40,072
Other	45,845	45,489
	8,178,916	8,191,107
Less accumulated depreciation, depletion, amortization, and impairment	5,700,840	5,609,980
Net property and equipment	2,478,076	2,581,127
Goodwill	62,808	62,808
Non-current derivative asset (Note 10)	942	968
Other assets	15,170	14,681
Total assets	\$ 2,681,088	\$ 2,799,842

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

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CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	March 31, 2016	December 31, 2015
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 67,504	\$ 87,413
Accrued liabilities (Note 5)	52,854	46,918
Current portion of other long-term liabilities (Note 6)	19,053	16,560
Total current liabilities	139,411	150,891
Long-term debt less debt issuance costs (Note 6)	898,722	918,995
Non-current derivative liability (Note 10)	185	285
Other long-term liabilities (Note 6)	106,930	140,341
Deferred income taxes	254,800	275,750
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, 51,440,785 and 50,413,101 shares issued as of March 31, 2016 and December 31, 2015, respectively	10,012	9,831
Capital in excess of par value	494,999	486,571
Retained earnings	776,029	817,178
Total shareholders' equity	1,281,040	1,313,580
Total liabilities and shareholders' equity	\$ 2,681,088	\$ 2,799,842

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

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CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended March 31,	
	2016	2015
	(In thousands except per share amounts)	
Revenues:		
Oil and natural gas	\$58,274	\$106,069
Contract drilling	38,710	95,077
Gas gathering and processing	39,200	53,953
Total revenues	136,184	255,099
Expenses:		
Oil and natural gas:		
Operating costs	33,346	45,211
Depreciation, depletion, and amortization	31,832	77,118
Impairment of oil and natural gas properties (Note 2)	37,829	400,593
Contract drilling:		
Operating costs	28,098	51,746
Depreciation	12,195	15,013
Gas gathering and processing:		
Operating costs	31,066	44,175
Depreciation and amortization	11,459	10,694
General and administrative	8,715	9,370
Gain on disposition of assets	(192)	(545)
Total operating expenses	194,348	653,375
Loss from operations	(58,164)	(398,276)
Other income (expense):		
Interest, net	(9,617)	(7,240)
Gain on derivatives	10,929	6,586
Other	(15)	(2)
Total other income (expense)	1,297	(656)
Loss before income taxes	(56,867)	(398,932)
Income tax expense (benefit):		
Current	—	65
Deferred	(15,718)	(150,643)
Total income taxes	(15,718)	(150,578)
Net loss	\$(41,149)	\$(248,354)
Net loss per common share:		
Basic	\$(0.83)	\$(5.07)
Diluted	\$(0.83)	\$(5.07)

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

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
OPERATING ACTIVITIES:		
Net loss	\$ (41,149)	\$ (248,354)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, and amortization	56,116	103,590
Impairment of oil and natural gas properties (Note 2)	37,829	400,593
Gain on derivatives	(10,929)	(6,586)
Cash receipts on derivatives settled	7,140	11,012
Deferred tax benefit	(15,718)	(150,643)
Gain on disposition of assets	(469)	(545)
Employee stock compensation plans	4,798	5,863
Other, net	(1,269)	1,374
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	10,003	51,910
Accounts payable	11,013	(3,131)
Material and supplies	262	(2,387)
Accrued liabilities	10,702	(6,295)
Other, net	2,384	3,908
Net cash provided by operating activities	70,713	160,309
INVESTING ACTIVITIES:		
Capital expenditures	(76,035)	(233,412)
Proceeds from disposition of assets	38,380	2,385
Other	169	—
Net cash used in investing activities	(37,486)	(231,027)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	75,000	224,399
Payments under credit agreement	(95,800)	(153,100)
Payments on capitalized leases	(910)	(874)
Tax expense from stock compensation	(376)	—
Book overdrafts	(11,237)	108
Net cash (used in) provided by financing activities	(33,323)	70,533
Net decrease in cash and cash equivalents	(96)	(185)
Cash and cash equivalents, beginning of period	835	1,049
Cash and cash equivalents, end of period	\$ 739	\$ 864
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)		(2,024) (4,475)
Income taxes		— 500
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	19,685	83,566
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	28,417	6,087
The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.		

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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The accompanying 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.

The accompanying 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 25, 2016, for the year ended December 31, 2015.

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

Balance Sheets at March 31, 2016 and December 31, 2015;
Statements of Operations for the three months ended March 31, 2016 and 2015; and
Statements of Cash Flows for the three months ended March 31, 2016 and 2015.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three months ended March 31, 2016 and 2015 are not necessarily indicative of the results to be realized for the full year of 2016, or that we realized for the full year of 2015.

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

Regarding the unaudited financial information for the three month periods ended March 31, 2016 and 2015, our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures under professional standards in reviewing that information. Its separate report dated May 5, 2016, which is included in this report, states it did not audit and it expresses no opinion on that unaudited financial information. The reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (Act) for its report on the unaudited financial information because that report is not a “report” or a “part” of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 – OIL AND NATURAL GAS PROPERTIES

Full cost accounting rules require us to review the carrying value of our oil and natural gas properties at the end of each quarter. Under those rules, the maximum amount allowed as the carrying value is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (using the unescalated 12-month average price of our oil, NGLs, and natural gas), plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net book value of the oil, NGLs, and natural gas properties

being amortized exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs, even if prices are depressed for only a short while. Once incurred, a write-down of oil and natural gas properties is not reversible.

During the first quarter of 2015, the 12-month average commodity prices decreased significantly, resulting in a non-cash ceiling test write-down of \$400.6 million pre-tax (\$249.4 million, net of tax).

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During the first quarter of 2016, the 12-month average commodity prices decreased further, resulting in a non-cash ceiling test write-down of \$37.8 million pre-tax (\$23.5 million, net of tax).

NOTE 3 – DIVESTITURES

Oil and Natural Gas

We sold non-core oil and natural gas assets, net of related expenses, for \$37.4 million during the first quarter of 2016, compared to less than \$0.1 million during the first quarter of 2015. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

NOTE 4 – LOSS PER SHARE

Information related to the calculation of loss per share follows:

	Loss (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended March 31, 2016			
Basic loss per common share	\$ (41,149)	49,880	\$ (0.83)
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	—	—
Diluted loss per common share	\$ (41,149)	49,880	\$ (0.83)
For the three months ended March 31, 2015			
Basic loss per common share	\$ (248,354)	48,977	\$ (5.07)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted loss per common share	\$ (248,354)	48,977	\$ (5.07)

Due to the net loss for the three months ended March 31, 2016, approximately 235,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and were excluded from the earnings per share calculation above. For the three months ended March 31, 2015, approximately 159,000 weighted average shares were excluded.

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 March 31, 2016 2015	
Stock options and SARs	261,270	291,770
Average exercise price	\$50.34	\$50.22

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NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2016	December 31, 2015
	(In thousands)	
Interest payable	\$ 16,991	\$ 6,321
Lease operating expenses	16,408	17,220
Employee costs	7,237	12,641
Taxes	5,780	3,767
Third-party credits	3,966	3,326
Other	2,472	3,643
Total accrued liabilities	\$ 52,854	\$ 46,918

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

Long-Term Debt

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

	March 31, 2016	December 31, 2015
	(In thousands)	
Credit agreement with an average interest rate of 2.2% and 2.6% at March 31, 2016 and December 31, 2015, respectively	\$ 260,200	\$ 281,000
6.625% senior subordinated notes due 2021, net of unamortized discount and debt issuance costs of \$11,478 and \$12,005 at March 31, 2016 and December 31, 2015, respectively	638,522	637,995
Total long-term debt	\$ 898,722	\$ 918,995

Credit Agreement. On April 8, 2016, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on April 10, 2020. The details of this amendment are discussed in Note 13 – Subsequent Events.

Prior to the amendment and through March 31, 2016, the amount we could borrow was the lesser of the amount we elected as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of \$900.0 million. Our elected commitment amount was \$500.0 million. Our borrowing base was \$550.0 million. We were charged a commitment fee ranging from 0.375% to 0.50% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. We paid \$2.6 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

The borrowing base amount—which is subject to redetermination by the lenders on April 1st and October 1st of each year—is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a 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 credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75%

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 credit agreement that cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At March 31, 2016, we had \$260.2 million outstanding borrowings under our credit agreement.

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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, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The 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; and
- 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.

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

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

As of March 31, 2016, we were in compliance with the covenants in the credit agreement.

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

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for issuing the Notes. The Guarantors are all 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 independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

Before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital

stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of March 31, 2016.

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Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, December 31,	
	2016	2015
	(In thousands)	
Asset retirement obligation (ARO) liability	\$70,759	\$ 98,297
Capital lease obligations	21,592	22,466
Workers' compensation	16,735	16,551
Separation benefit plans	8,301	9,886
Deferred compensation plan	4,381	4,244
Gas balancing liability	3,805	5,047
Other	410	410
	125,983	156,901
Less current portion	19,053	16,560
Total other long-term liabilities	\$106,930	\$ 140,341

Estimated annual principal payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2016 (and through 2021) are \$19.1 million, \$42.7 million, \$10.6 million, \$8.3 million, and \$269.8 million, respectively.

Capital Leases

During 2014, our mid-stream segment entered into capital lease agreements for twenty compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The current portion of our capital lease obligations of \$3.6 million is included in current portion of other long-term liabilities and the non-current portion of \$18.0 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of March 31, 2016. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are \$9.0 million and \$2.5 million, respectively at March 31, 2016. Annual payments, net of maintenance and interest, average \$4.0 million annually through 2021. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

Future payments required under the capital leases at March 31, 2016:

	Amount
	(In thousands)
Ending March 31,	
2017	\$ 6,168
2018	6,168
2019	6,168
2020	6,168
2021 and thereafter	8,394
Total future payments	33,066
Less payments related to:	
Maintenance	8,998
Interest	2,476
Present value of future minimum payments	\$ 21,592

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NOTE 7 – ASSET RETIREMENT OBLIGATIONS

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

	Three Months Ended	
	March 31,	
	2016	2015
	(In thousands)	
ARO liability, January 1:	\$98,297	\$100,567
Accretion of discount	879	932
Liability incurred	90	5,174
Liability settled	(375)	(760)
Liability sold ⁽¹⁾	(9,950)	(240)
Revision of estimates ⁽²⁾	(18,182)	(10,232)
ARO liability, March 31:	70,759	95,441
Less current portion	3,499	3,467
Total long-term ARO	\$67,260	\$91,974

(1) We sold approximately 1,000 wells to unaffiliated third-parties during the first quarter of 2016.

(2) Plugging liability estimates were revised in both 2016 and 2015 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

Compensation—Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB has issued ASU 2016-09. The amendments are intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public companies, the amendments are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption of the amendments is permitted. The amendments primarily impact classification within the statement of cash flows between financial and operating activities.

Leases. The FASB has issued ASU 2016-02. Under the new guidance, lessees will be required to recognize at the commencement date a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use a specified asset for the lease term. Lessor accounting is largely unchanged. For public companies, the amendments are effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. Early adoption of the amendments is permitted. We are in the process of evaluating the impact it will have on our financial statements.

Income Taxes: Balance Sheet Classification of Deferred Taxes. The FASB has issued ASU 2015-17. This changes how deferred taxes are classified on organizations' balance sheets. Organizations will be required to classify all deferred tax assets and liabilities as noncurrent. The amendments apply to all organizations that present a classified balance sheet. For public companies, the amendments are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption of the amendments is permitted. The amendments will require current deferred tax assets to be combined with noncurrent deferred tax assets.

Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs. The FASB has issued ASU 2015-03. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the

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balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The FASB has also issued ASU 2015-15. The amendments in this ASU allow an entity to defer and present debt issuance cost as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. We have maintained debt issuance costs associated with our credit agreement as an asset and amortize these fees over the life of the credit agreement. For public business entities, the amendments are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments should be applied on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. We have adopted these amendments this quarter. Previously, debt issuance costs associated with the Notes was classified as a long-term asset on the balance sheet, but with ASU 2015-03, it is presented as a direct deduction from the carrying amount of the recognized debt liability.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In April 2016, the FASB issued ASU 2016-10, "Identifying Performance Obligations and Licensing," which amends the revenue guidance on identifying performance obligations and accounting for licenses of intellectual property. On April 1, 2015, the FASB proposed deferring the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. We are in the process of evaluating the impact it will have on our financial statements.

NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended March 31, 2016	2015
	(In millions)	
Recognized stock compensation expense	\$3.3	\$4.3
Capitalized stock compensation cost for our oil and natural gas properties	0.8	0.9
Tax benefit on stock based compensation	1.3	1.7

The remaining unrecognized compensation cost related to unvested awards at March 31, 2016 is approximately \$12.5 million, of which \$2.1 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 of a year.

The Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the amended plan) allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as to non-employee directors. A total of 4,500,000 shares of the company's common stock is 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."

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We did not grant any SARs or stock options during either of the three month periods ending March 31, 2016 and 2015. The following table shows the fair value of restricted stock awards granted to employees and non-employee directors during the first three months ended March 31, 2016 and 2015.

	2016		2015	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	486,578	152,373	576,361	148,081
Non-employee directors	—	—	—	—
	486,578	152,373	576,361	148,081
Estimated fair value (in millions): ⁽¹⁾				
Employees	\$2.6	\$ 0.8	\$19.6	\$ 5.1
Non-employee directors	—	—	—	—
	\$2.6	\$ 0.8	\$19.6	\$ 5.1
Percentage of shares granted expected to be distributed:				
Employees	94 %	52 %	94 %	2 %
Non-employee directors	N/A	N/A	N/A	N/A

(1) Represents 100% of the grant date fair value. (We recognize the grant date fair value minus estimated forfeitures.)

The time vested restricted stock awards granted during the first three months of 2016 and 2015 are being recognized over a three year vesting period. During the first quarter of 2016, there were two different performance vested restricted stock awards granted to certain executive officers. The first will cliff vest three years from the grant date based on the company's achievement of certain stock performance measures at the end of the term and will range from 0% to 150% of the restricted shares granted as performance shares. The second will vest, one-third each year, over a three year vesting period based on the company's achievement of cash flow to total assets performance measurement each year and will range from 0% to 200%. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2016 awards for the first three months of 2016 was \$0.1 million.

NOTE 10 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production subject to a derivative contract are based, in part, on our view of current and future market conditions. As of March 31, 2016, our derivative transactions comprised the following hedges:

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

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

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.

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We have documented policies and procedures to monitor and control the use of derivative transactions. We do not engage in derivative transactions for speculative purposes. For our economic hedges any changes in fair value occurring before maturity (i.e., temporary fluctuations in value) are reported in gain on derivatives in our Unaudited Condensed Consolidated Statements of Operations.

At March 31, 2016, we had the following derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr' 16 – Dec' 16	Natural gas – swap	45,000 MMBtu/day	\$2.596	IF – NYMEX (HH)
Jan' 17 – Dec' 17	Natural gas – swap	10,000 MMBtu/day	\$2.795	IF – NYMEX (HH)
Apr' 16 – Dec' 16	Natural gas – collar	42,000 MMBtu/day	\$2.40 - \$2.88	IF – NYMEX (HH)
Apr' 16 – Dec' 16	Natural gas – three-way collar	13,500 MMBtu/day	\$2.70 - \$2.20 - \$3.26	IF – NYMEX (HH)
Jan' 17 – Dec' 17	Natural gas – three-way collar	15,000 MMBtu/day	\$2.50 - \$2.00 - \$3.32	IF – NYMEX (HH)
Apr' 16 – Jun' 16	Crude oil – collar	5,150 Bbl/day	\$40.71 - \$49.88	WTI – NYMEX
Jul' 16 – Dec' 16	Crude oil – collar	1,450 Bbl/day	\$47.50 - \$56.40	WTI – NYMEX
Apr' 16 – Dec' 16	Crude oil – three-way collar	700 Bbl/day	\$46.50 - \$35.00 - \$57.00	WTI – NYMEX
Jul' 16 – Dec' 16	Crude oil – three-way collar ⁽¹⁾	700 Bbl/day	\$47.50 - \$35.00 - \$63.50	WTI – NYMEX
Jan' 17 – Dec' 17	Crude oil – three-way collar	750 Bbl/day	\$50.00 - \$37.50 - \$63.90	WTI – NYMEX

(1) We pay our counterparty a premium, which can be and is being deferred until settlement.

After March 31, 2016, we entered into the following derivatives:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan' 17 – Dec' 17	Natural gas – swap	20,000 MMBtu/day	\$2.960	IF – NYMEX (HH)
Jan' 17 – Oct' 17	Natural gas – collar	10,000 MMBtu/day	\$2.75 - \$2.95	IF – NYMEX (HH)
Jul' 16 – Sep' 16	Crude oil – collar	1,000 Bbl/day	\$40.00 - \$46.75	WTI – NYMEX

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

		Derivative Assets	
		Fair Value	
	Balance Sheet Location	March 31, 2016	December 31, 2015
(In thousands)			
Commodity derivatives:			
Current	Current derivative asset	\$ 13,901	\$ 10,186
Long-term	Non-current derivative asset	942	968
Total derivative assets		\$ 14,843	\$ 11,154

Balance Sheet Location		Derivative Liabilities Fair Value	
		March 31, 2016	December 31, 2015
(In thousands)			
Commodity derivatives:			
Long-term	Non-current derivative liability	\$ 185	\$ 285
Total derivative liabilities		\$ 185	\$ 285

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.

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

Derivatives Instruments	Location of Gain Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative	
		2016	2015
		(In thousands)	
Commodity derivatives	Gain on derivatives ⁽¹⁾	\$ 10,929	\$ 6,586
Total		\$ 10,929	\$ 6,586

(1) Amounts settled during the 2016 and 2015 periods include gains of \$7.1 million and \$11.0 million, respectively.

NOTE 11 – FAIR VALUE MEASUREMENTS

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

Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.

Level 2—significant observable pricing inputs other than quoted prices included within level 1 either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are

derived principally from or corroborated by observable market data.

• Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data.

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

The following tables set forth our recurring fair value measurements:

March 31, 2016				
	Level 2	Level 3	Effect of Netting	Net Amounts Presented
(In thousands)				
Financial assets (liabilities):				
Commodity derivatives:				
Assets	\$4,675	\$10,230	\$ (62)	\$ 14,843
Liabilities	—	(247)	62	(185)
	\$4,675	\$9,983	\$ —	\$ 14,658
December 31, 2015				
	Level 2	Level 3	Effect of Netting	Net Amounts Presented
(In thousands)				
Financial assets (liabilities):				
Commodity derivatives:				
Assets	\$2,794	\$10,145	\$(1,785)	\$ 11,154
Liabilities	(1,019)	(1,051)	1,785	(285)
	\$1,775	\$9,094	\$—	\$ 10,869

All of our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post any cash collateral with our counterparties and no collateral has been posted as of March 31, 2016.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

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.

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

	Net Derivatives Three Months Ended March 31, 2016 2015 (In thousands)	
Beginning of period	\$9,094	\$3,355
Total gains or losses (realized and unrealized):		
Included in earnings ⁽¹⁾	5,988	777
Settlements	(5,099)	(3,275)
End of period	\$9,983	\$857
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held at end of period	\$889	\$(2,498)

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

The following table provides quantitative information about our Level 3 unobservable inputs at March 31, 2016:

Commodity ⁽¹⁾	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil collars	\$ 3,247	Discounted cash flow	Forward commodity price curve	\$0.00 - \$8.79
Oil three-way collars	\$ 2,696	Discounted cash flow	Forward commodity price curve	\$0.00 - \$10.13
Natural gas collar	\$ 3,141	Discounted cash flow	Forward commodity price curve	\$0.00 - \$0.65
Natural gas three-way collars	\$ 899	Discounted cash flow	Forward commodity price curve	\$0.00 - \$0.85

The commodity contracts detailed in this category include non-exchange-traded crude oil and natural gas collars (1) and 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.

Based on our valuation at March 31, 2016, we determined that risk of non-performance by our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At March 31, 2016, the carrying values on the Unaudited Condensed Consolidated Balance Sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and also considering the risk of our non-performance, long-term debt under our credit agreement approximates its fair

value and at March 31, 2016 was \$260.2 million. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount and debt issuance costs, associated with the Notes reported in the Unaudited Condensed Consolidated Balance Sheets as of March 31, 2016 and December 31, 2015 were \$638.5 million and \$638.0 million, respectively. We estimate the fair value of these Notes using quoted marked prices at March 31, 2016 and December 31, 2015 were \$337.2 million and \$455.5 million, respectively. These Notes would be classified as Level 2.

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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 – INDUSTRY SEGMENT INFORMATION

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

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

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

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. We have no oil and natural gas production outside the United States.

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

	Three Months Ended March 31, 2016 2015 (In thousands)	
Revenues:		
Oil and natural gas	\$58,274	\$106,069
Contract drilling	38,710	104,938
Elimination of inter-segment revenue	—	(9,861)
Contract drilling net of inter-segment revenue	38,710	95,077
Gas gathering and processing	49,045	73,804
Elimination of inter-segment revenue	(9,845)	(19,851)
Gas gathering and processing net of inter-segment revenue	39,200	53,953
Total revenues	\$136,184	\$255,099
Operating loss:		
Oil and natural gas	\$(44,733)	\$(416,853)
Contract drilling	(1,583)	28,318
Gas gathering and processing	(3,325)	(916)
Total operating loss ⁽¹⁾	(49,641)	(389,451)
General and administrative	(8,715)	(9,370)
Gain on disposition of assets	192	545
Gain on derivatives	10,929	6,586
Interest expense, net	(9,617)	(7,240)
Other	(15)	(2)
Loss before income taxes	\$(56,867)	\$(398,932)

Operating loss is total operating revenues less operating expenses, depreciation, depletion, amortization, and (1) impairment and does not include general corporate expenses, gain on disposition of assets, gain on derivatives, interest expense, other income (loss), or income taxes.

NOTE 13 – SUBSEQUENT EVENT

On April 8, 2016, we entered into a Third Amendment to our Senior Credit Agreement (Third Amendment). The Third Amendment, provides, among other things, (i) for a reduction of the total commitment of credit from \$500.0 million to \$475.0 million; (ii) for a reduction of the maximum credit amount from \$900.0 million to \$875.0 million; (iii) a reduction in the borrowing base from \$550.0 million to \$475.0 million; (iv) for exclusion of non-cash expenses associated with stock-based plans and all other non-cash charges from the definitions of Consolidated EBITDA and Consolidated Net Income; (v) that we must maintain a senior indebtedness to consolidated EBITDA ratio for the most-recently ended rolling four quarters no greater than 2.75 to 1.0 for each fiscal quarter through the fiscal quarter ending March 31, 2019 and, starting with the fiscal quarter ending June 30, 2019, we will not permit the ratio, determined as of the end of each applicable fiscal quarter, of (a) funded debt to (b) Consolidated EBITDA for the then most-recently ended rolling four fiscal quarters to be greater than 4.0 to 1.0; (vi) that we pledge the following collateral: (a) 85% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties and (b) 100% of our ownership interest in our midstream affiliate, Superior Pipeline Company, L.L.C.;

(vii) that loans will bear interest at specified margins over the base rate of 1.00% to 3.00% or LIBOR of 2.00% to 3.00% for alternate base rate loans and Eurodollar-based loans, respectively; (viii) a commitment fee of 0.50% on the amount available but not borrowed; and (ix) for a release of our collateral obligations during any period (or periods) in which we meet certain ratings requirements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying unaudited condensed consolidated balance sheets of Unit Corporation and its subsidiaries as of March 31, 2016, and the related unaudited condensed consolidated statements of operations for the three-month periods ended March 31, 2016 and 2015 and the unaudited condensed consolidated statements of cash flows for the three-month periods ended March 31, 2016 and 2015. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2015, and the related consolidated statements of operations, and of cash flows for the year then ended (not presented herein), and in our report dated February 25, 2016, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2015, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 5, 2016

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

Management's Discussion and Analysis (MD&A) provides an understanding of our operating results and financial condition by focusing on changes in certain key measures from year to year. We have organized MD&A into the following sections:

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

Please read the following discussion and our unaudited condensed consolidated financial statements and related notes with the information in our most recent Annual Report on Form 10-K.

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.

General

We operate, manage, and analyze our results of operations through our three principal business segments:

- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Contract Drilling – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our business and each of our three main operating segments depend, on a large part, on the prices we receive for our oil and natural gas production and the demand for oil and natural gas as well as the demand for our drilling rigs which, in turn, influences the amounts we can charge for those drilling rigs. While our operations are located within the United States, events outside the United States can affect us and our industry.

Both within the United States and the world, deteriorating commodity prices during the past 18 or so months brought about significant changes adversely affecting our industry and us. The decline in commodity prices has caused us (and other oil and gas companies) to reduce (or even stop) our level of drilling activity and spending. When drilling activity and spending decline for any sustained period of time the rates for and the number of our drilling rigs working also tend to decline. In addition, lower commodity prices for any sustained period of time could impact the liquidity condition of some of our industry partners and customers, which, in turn, might limit their ability to meet their financial obligations to us.

It is uncertain how long the current depressed prices for oil and natural gas products will continue. As noted elsewhere in this report, commodity prices are subject to a number of factors most of which are not within our control.

The impact on our business and financial results from the reduction in oil, NGLs, and natural gas prices has had a number of consequences for us, including the following:

We incurred a non-cash ceiling test write-down in the first quarter of 2016 of \$37.8 million (\$23.5 million net of tax) and expect a further write-down in the second quarter of 2016. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward reserve revisions,

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reserve additions, and tax attributes. Subject to these numerous factors and inherent limitations, holding these factors constant and only adjusting the 12-month average price to an estimated second quarter ending average (holding April 2016 prices constant for the remaining two months of the second quarter of 2016), we currently anticipate that we could recognize an impairment in the second quarter of 2016 of approximately \$125 million pre-tax. The impact of the significantly higher commodity prices used in the ceiling test 12-month average price calculation will lessen as those higher prices will roll off from the calculation.

We have reduced the number of gross wells we plan to drill in 2016 by approximately 57-74% from the number of gross wells drilled in 2015 due to reduced cash flow from lower commodity prices.

Several of our drilling rig customers significantly reduced their drilling budgets, resulting in a significant reduction in the average utilization of our drilling rig fleet. At December 31, 2015, we had 26 drilling rigs operating and at April 22, 2016, this number was 14. We currently expect further reductions in 2016.

- Due to the low NGLs prices, we are operating our processing facilities in full ethane rejection mode which reduces the amount of liquids sold. As long as NGLs prices continue to be depressed, we expect to continue operating in full ethane rejection mode. As low commodity prices continue, we expect the reductions in drilling activity around our systems will reduce the number of new wells available to connect to our systems and result in lower processed volumes as production from wells previously connected naturally decline.

Effective with the April 2016 Third Amendment, the lenders of our credit agreement decreased our borrowing base from \$550.0 million to \$475.0 million. Our commitment under the credit agreement decreased from \$500.0 million to \$475.0 million. At April 22, 2016, borrowings were \$263.0 million. We believe our liquidity will be adequate to carry out our 2016 capital plans.

We have reduced our total 2016 capital budget by a range of approximately 59-65% as compared to 2015, excluding acquisitions and ARO liability. Our budget is designed to keep our capital expenditures below our anticipated cash flow and proceeds from non-core asset sales.

Our 2016 current capital budget is based on realized prices for the year of \$34.57 per barrel of oil, \$8.01 per barrel of NGLs, and \$2.24 per Mcf of natural gas. Our budget is subject to possible periodic adjustments for various reasons including changes in commodity prices and industry conditions. Funding for the budget will come primarily from our cash flow, non-core asset sales, and, if necessary, borrowings under our credit agreement.

In response to the adverse impacts that lower commodity prices had on us in 2015 (as well as our industry) we carried out the following during the first quarter of 2016:

We consolidated from five to two the number of divisions within our drilling segment allowing for us to further reduce the costs associated with operating the divisions.

The higher end of our 2016 capital expenditure budget for exploration and production segment is designed with the intent to incur the majority of those expenditures in the latter part of the year thus allowing us to take into account future commodity price movement before we incur those expenditures.

We have implemented certain reductions in our office and field workforces to account for the reduction in our operating activities as well as a reduction of compensation paid to drilling personnel.

Through March 31, 2016, we have sold approximately \$37.4 million of non-core oil and gas properties using the majority of the proceeds to pay down borrowings under our bank credit agreement.

Executive Summary

Oil and Natural Gas

First quarter 2016 production from our oil and natural gas segment was 4,514,000 barrels of oil equivalent (Boe), a decrease of 5% and 12% from the fourth quarter of 2015 and the first quarter of 2015, respectively. The production

decrease was primarily due to reduced drilling activity resulting from lower oil and NGLs prices.

First quarter 2016 oil and natural gas revenues decreased 23% and 45% from the fourth quarter of 2015 and the first quarter of 2015, respectively. The decreases were due primarily to lower oil, NGLs, and natural gas prices and to a lesser extent from reduced production volumes.

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Our oil prices for the first quarter of 2016 decreased 33% from both the fourth quarter of 2015 and the first quarter of 2015. Our NGLs prices decreased 40% from the fourth quarter of 2015 and decreased 24% from the first quarter of 2015. Our natural gas prices decreased 17% from the fourth quarter of 2015 and decreased 36% from the first quarter of 2015.

Operating cost per Boe produced for the first quarter of 2016 decreased 3% from the fourth quarter of 2015 and decreased 16% from the first quarter of 2015. Costs were lower between the comparative quarters primarily due to lower lease operating expenses, saltwater disposal expense, and general and administrative expenses.

At March 31, 2016, we had the following derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr'16 – Dec'16	Natural gas – swap	45,000 MMBtu/day	\$2.596	IF – NYMEX (HH)
Jan'17 – Dec'17	Natural gas – swap	10,000 MMBtu/day	\$2.795	IF – NYMEX (HH)
Apr'16 – Dec'16	Natural gas – collar	42,000 MMBtu/day	\$2.40 - \$2.88	IF – NYMEX (HH)
Apr'16 – Dec'16	Natural gas – three-way collar	13,500 MMBtu/day	\$2.70 - \$2.20 - \$3.26	IF – NYMEX (HH)
Jan'17 – Dec'17	Natural gas – three-way collar	15,000 MMBtu/day	\$2.50 - \$2.00 - \$3.32	IF – NYMEX (HH)
Apr'16 – Jun'16	Crude oil – collar	5,150 Bbl/day	\$40.71 - \$49.88	WTI – NYMEX
Jul'16 – Dec'16	Crude oil – collar	1,450 Bbl/day	\$47.50 - \$56.40	WTI – NYMEX
Apr'16 – Dec'16	Crude oil – three-way collar	700 Bbl/day	\$46.50 - \$35.00 - \$57.00	WTI – NYMEX
Jul'16 – Dec'16	Crude oil – three-way collar ⁽¹⁾	700 Bbl/day	\$47.50 - \$35.00 - \$63.50	WTI – NYMEX
Jan'17 – Dec'17	Crude oil – three-way collar	750 Bbl/day	\$50.00 - \$37.50 - \$63.90	WTI – NYMEX

(1) We pay our counterparty a premium, which can be and is being deferred until settlement.

After March 31, 2016, we entered into the following derivatives:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'17 – Dec'17	Natural gas – swap	20,000 MMBtu/day	\$2.960	IF – NYMEX (HH)
Jan'17 – Oct'17	Natural gas – collar	10,000 MMBtu/day	\$2.75 - \$2.95	IF – NYMEX (HH)
Jul'16 – Sep'16	Crude oil – collar	1,000 Bbl/day	\$40.00 - \$46.75	WTI – NYMEX

For the three months ended March 31, 2016, we completed drilling eight gross wells (4.99 net wells). For all of 2016, we plan to participate in the drilling of approximately 15-25 gross wells. Excluding acquisitions and ARO liability, our estimated 2016 capital expenditures for this segment range from \$109.0 to \$131.0 million. Our current 2016 production guidance is approximately 16.9 to 17.4 MMBoe, a decrease of 13% to 16% over 2015, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated for the first quarter of 2016 was 20.6 compared to 27.2 and 50.1 in the fourth quarter of 2015 and the first quarter of 2015, respectively. Late in the fourth quarter of 2014, the number of our drilling rigs operating started to decline and has continued to decline through the first quarter of 2016 because of lower commodity prices and operators reducing their drilling budgets. As of March 31, 2016, 15 of our drilling rigs were operating.

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Revenue for the first quarter of 2016 decreased 23% and 59% from the fourth quarter of 2015 and the first quarter of 2015, respectively. The decreases were due primarily to fewer drilling rigs operating and lower dayrates.

Dayrates for the first quarter of 2016 averaged \$18,392, a 1% decrease from the fourth quarter of 2015 and a 9% decrease from the first quarter of 2015. The decreases were primarily due to downward pressure on dayrates from lower demand.

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Operating costs for the first quarter of 2016 decreased 14% and 46% from the fourth quarter of 2015 and the first quarter of 2015, respectively. The decreases were due primarily to fewer drilling rigs operating.

Almost all of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The continued low commodity prices for oil and natural gas has changed demand for drilling rigs. These factors affect the demand and mix of the type of drilling rigs used by our customers and that demand will impact our future dayrates.

As of March 31, 2016, we had eight term drilling contracts with original terms ranging from six months to three years. Four of these contracts are up for renewal in 2016, (two in the second quarter, one in the third quarter, and one in the fourth quarter) and four are up for renewal in 2017. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate. Some operators who had signed term contracts have opted to release the drilling rig and pay an early termination penalty for the remaining term of the contract. During the first quarter of 2016, we recorded \$2.6 million in early termination fees compared to \$3.3 million in the fourth quarter of 2015 and \$12.7 million in the first quarter of 2015..

As of March 31, 2016, seven of our eight new BOSS drilling rigs were under contract. Currently, we do not have any contracts to build any new BOSS drilling rigs. Our anticipated 2016 capital expenditures for this segment is \$9.0 million to \$11.0 million, an 87-89% decrease from 2015.

Mid-Stream

First quarter 2016 liquids sold per day decreased 8% and 9% from the fourth quarter of 2015 and the first quarter of 2015, respectively. The decrease from the fourth quarter of 2015 was due to rejecting more liquids at our processing facilities and to a lesser extent due to less volume to process. The decrease from the first quarter of 2015 was due to less volume to process at our plants. For the first quarter of 2016, gas processed per day decreased 2% from the fourth quarter of 2015 and decreased 12% from the first quarter of 2015. The decreases were primarily due to declines in existing volumes and fewer new wells connected. For the first quarter of 2016, gas gathered per day increased 6% over the fourth quarter of 2015 and increased 15% over the first quarter of 2015. The increases were primarily from additional wells added to our Pittsburgh Mills gathering system.

NGLs prices in the first quarter of 2016 decreased 17% from the prices received in the fourth quarter of 2015 and decreased 33% from the prices received in the first quarter of 2015. Because certain of the contracts used by our mid-stream segment for NGLs transactions are commodity-based contracts—under which we receive a share of the proceeds from the sale of the NGLs—our revenues from those commodity-based contracts fluctuate based on the price of NGLs.

Total operating cost for our mid-stream segment for the first quarter of 2016 decreased 15% from the fourth quarter of 2015 and decreased 30% from the first quarter of 2015 due to lower gas purchase prices and lower purchase volumes.

At our Hemphill Texas system, total processing capacity is 135 MMcf per day and for the first quarter of 2016, our total throughput volume averaged 72.1 MMcf per day.

In the Mississippian play in north central Oklahoma, our Bellmon gathering system throughput volume averaged approximately 36.2 MMcf per day for the first quarter of 2016. During the first quarter of 2016, we connected five additional wells to this gathering system. This processing facility has a total processing capacity of approximately 90 MMcf per day.

In Southeast Texas, our Segno gathering facility, averaged approximately 85 MMcf per day of throughput for the quarter. We connected two new wells to this gathering system in the quarter. Our total gathering capacity for this

system is 120 MMcf per day.

In the Appalachian region, at our Pittsburgh Mills gathering system, our average throughput volume for the quarter was 92.3 MMcf per day. Two new well pads were connected during the quarter. In February, we connected the Kane well pad which included five new wells. In March, we connected the Gulick well pad which also included five new wells. This well pad is located on the southern portion of the gathering system. We anticipate two additional well pads to be connected this year. These new pads are expected to be connected in the third quarter of 2016.

Also in the Appalachian area, at our new Snow Shoe gathering system, we connected three new wells during the quarter. Our average throughput volume for the quarter was approximately 7.1 MMcf per day. We are in the process of connecting additional wells from another producer to this system. These new wells will be connected in the second quarter of 2016.

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Our estimated 2016 capital expenditures for this segment range from \$22.0 million to \$24.0 million.

Financial Condition and Liquidity

Summary

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

- the quantity 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 currently believe we have sufficient 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 agreement as well as our Indenture) and our capacity to incur additional indebtedness will depend on our future performance, which in turn will be affected by financial, business, economic, regulatory, and other factors. For example, lower oil, natural gas, and NGLs prices since the last credit agreement amendment could result in a redetermination of the borrowing base to a lower level and therefore reduce or limit our ability to incur indebtedness. As a result, we monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues and work with the lenders under our credit agreement to address those issues, if any, ahead of time.

As part of our plan to manage liquidity risks, we have lowered our capital expenditures budget, focused our drilling program on our highest return plays, and continue to explore opportunities to divest non-core assets and properties. During the quarter, we sold approximately \$37.4 million of non-core oil and gas properties using the majority of the proceeds to pay down borrowings under our bank credit agreement. If necessary, we could sell other non-core assets and use the proceeds to further reduce our outstanding borrowings.

	Three Months Ended March 31,		% Change ⁽¹⁾
	2016	2015	
	(In thousands except percentages)		
Net cash provided by operating activities	\$ 70,713	\$ 160,309	(56)%
Net cash used in investing activities	(37,486)	(231,027)	(84)%
Net cash (used in) provided by financing activities	(33,323)	70,533	(147)%
Net decrease in cash and cash equivalents	\$ (96)	\$ (185)	

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, third-party demand for our drilling rigs and mid-stream services, and the rates we can charge for those services. Our cash flows from operating activities are also impacted by changes in working capital.

Net cash provided by operating activities in the first three months of 2016 decreased by \$89.6 million from the first three months of 2015 due to lower revenues resulting from lower commodity prices and lower drilling rig utilization and by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital expenditure program toward the exploration for and production of oil, NGLs, and natural gas. These capital expenditures are necessary to off-set inherent declines in production, which is typical in the capital-intensive oil and natural gas industry.

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Cash flows used in investing activities decreased by \$193.5 million for the first three months of 2016 compared to the first three months of 2015. The change was due primarily to a decrease in capital expenditures partially offset by an increase in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows (used in) provided by financing activities decreased by \$103.9 million for the first three months of 2016 compared to the first three months of 2015. This decrease was primarily due to borrowings under our credit agreement and by a decrease in our book overdrafts (checks issued but not presented to our bank for payment before the end of the period).

At March 31, 2016, we had unrestricted cash totaling \$0.7 million and had borrowed \$260.2 million of the \$500.0 million we had elected to then have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of March 31, 2016 and 2015 and for the three months ended March 31, 2016 and 2015:

	March 31, 2016	2015	% Change
	(In thousands except percentages)		
Working capital	\$(15,319)	\$(16,369)	6 %
Long-term debt less debt issuance costs	\$898,722	\$873,726	3 %
Shareholders' equity	\$1,281,040	\$2,092,143	(39)%
Net loss	\$(41,149)	\$(248,354)	(83)%

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The following table summarizes certain operating information:

	Three Months Ended March 31,		% Change
	2016	2015	
Oil and Natural Gas:			
Oil production (MBbls)	803	1,098	(27)%
NGLs production (MBbls)	1,291	1,286	— %
Natural gas production (MMcf)	14,522	16,398	(11)%
Average oil price per barrel received	\$32.50	\$48.47	(33)%
Average oil price per barrel received excluding derivatives	\$28.54	\$44.66	(36)%
Average NGLs price per barrel received	\$6.59	\$8.65	(24)%
Average NGLs price per barrel received excluding derivatives	\$6.59	\$8.65	(24)%
Average natural gas price per Mcf received	\$1.87	\$2.94	(36)%
Average natural gas price per Mcf received excluding derivatives	\$1.59	\$2.52	(37)%
Contract Drilling:			
Average number of our drilling rigs in use during the period	20.6	50.1	(59)%
Total number of drilling rigs owned at the end of the period	94	91	3 %
Average dayrate	\$18,392	\$20,130	(9)%
Mid-Stream:			
Gas gathered—Mcf/day	383,405	334,278	15 %
Gas processed—Mcf/day	167,048	189,160	(12)%
Gas liquids sold—gallons/day	519,433	568,876	(9)%
Number of natural gas gathering systems	26	27	(4)%
Number of processing plants	13	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 \$15.3 million and \$16.4 million as of March 31, 2016 and 2015, respectively. This is primarily from the timing of our accounts payable associated with our capital expenditures partially offset by lower accounts receivable due to lower revenues. Our credit agreement is used primarily for working capital and capital expenditures. At March 31, 2016, we had borrowed \$260.2 million of the then \$500.0 million available as of March 31, 2016 under our credit agreement, subsequently reduced to \$475.0 million. The effect of our derivative contracts increased working capital by \$13.9 million as of March 31, 2016 and increased working capital by \$26.7 million as of March 31, 2015.

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. Domestic oil prices are primarily influenced by global oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first three months of 2016 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 \$462,000 per month (\$5.5 million

annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of derivatives, during the first three months of 2016 was \$1.87 compared to \$2.94 for the first three months of 2015. Based on our first three months of 2016 production, a \$1.00 per barrel change in our oil price, without the effect of derivatives, would have a \$258,000 per month (\$3.1 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 \$411,000 per month (\$4.9 million annualized) change in our pre-tax operating cash flow. In the first three months of 2016, our average oil price per barrel received, including the effect of

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derivatives, was \$32.50 compared with an average oil price, including the effect of derivatives, of \$48.47 in the first three months of 2015 and our first three months of 2016 average NGLs price per barrel received was \$6.59 compared with an average NGLs price per barrel of \$8.65 in the first three months of 2015.

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. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. A reduction could limit our ability to carry out our planned capital projects. In the first quarter of 2016, the unamortized cost of our oil and gas properties exceeded the ceiling of our proved oil, NGLs, and natural gas reserves. As a result, we recorded a non-cash ceiling test write down of \$37.8 million pre-tax (\$23.5 million, net of tax). At March 31, 2016, the 12-month average unescalated prices were \$46.26 per barrel of oil, \$18.01 per barrel of NGLs, and \$2.40 per Mcf of natural gas, then adjusted for price differentials.

We expect to incur a non-cash ceiling test write-down in the second quarter of 2016. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward reserve revisions, reserve additions, and tax attributes. Subject to these numerous factors and inherent limitations, holding these factors constant and only adjusting the 12-month average price to an estimated second quarter ending average (holding April 2016 prices constant for the remaining two months of the second quarter of 2016), we currently anticipate that we could recognize an impairment in the second quarter of 2016 of approximately \$125 million pre-tax. The estimated second quarter 2016 impairment is partially the result of a decrease in our proved undeveloped reserves of approximately 14%. These anticipated decreases are primarily due to certain locations no longer being economical under the adjusted 12-month average price for the second quarter. Based on this estimated 12-month average price, we would eliminate those locations from our future development plan. The impact of the significantly higher commodity prices used in the ceiling test 12-month average price calculation will lessen as those higher prices will roll off from the calculation. Given the uncertainty associated with the factors used in calculating our estimate of both our future period ceiling test write-down and the decrease in our undeveloped reserves, these estimates should not necessarily be construed as indicative of our future development plans or financial results.

Price declines can also adversely affect future semi-annual determinations of the amount we can borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects. Effective with the April 2016 Third Amendment, the lenders under our credit agreement decreased our borrowing base from \$550.0 million to \$475.0 million. Our commitment under the credit agreement decreased from \$500.0 million to \$475.0 million.

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 in six month increments.

Contract Drilling Operations

Many factors influence the number of drilling rigs we are working at any given time as well as 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.

Our drilling rig personnel are a key component to the overall success of our drilling services; however, due to the present conditions existing in the drilling industry, we reduced the compensation paid to all drilling personnel in April

2016.

Almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGLs. The continued low commodity price environment for oil and natural gas has changed demand for drilling rigs. These factors affect the demand and mix of the type of drilling rigs used by our customers and that demand will have an impact on our future dayrates. For the first three months of 2016, our average dayrate was \$18,392 per day compared to \$20,130 per day for the first three months of 2015. The average number of our drilling rigs used in the first three months of 2016 was 20.6 drilling rigs compared with 50.1 drilling rigs in the first three months of 2015. Based on the average utilization of our drilling rigs during the first three months of 2016, a \$100 per day change in dayrates has a \$2,060 per day (\$0.8 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment also provides drilling services for our oil and natural gas 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

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an ownership interest in the property. In those cases, revenues and expenses for those drilling services are eliminated in our statement of operations, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We did not eliminate any revenue in our contract drilling segment for the first quarter of 2016 with the intent for our oil and natural gas segment to incur the majority of its drilling capital expenditures in the latter part of the year thus allowing us to take into account future commodity price movement before those expenditures are incurred. For the first quarter of 2015, we eliminated revenue of \$9.9 million from our contract drilling segment and eliminated the associated operating expense of \$7.0 million, yielding \$2.9 million 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, 13 processing plants, 26 gathering systems, and approximately 1,465 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. Besides serving third parties, this segment also enhances our ability to gather and market our own natural gas and NGLs and serving as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first three months of 2016 and 2015, our mid-stream operations purchased \$7.6 million and \$17.9 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of \$2.2 million and \$2.0 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 383,405 Mcf per day in the first three months of 2016 compared to 334,278 Mcf per day in the first three months of 2015. It processed an average of 167,048 Mcf per day in the first three months of 2016 compared to 189,160 Mcf per day in the first three months of 2015. The amount of NGLs sold was 519,433 gallons per day in the first three months of 2016 compared to 568,876 gallons per day in the first three months of 2015. Gas gathering volumes per day in the first three months of 2016 increased 15% compared to the first three months of 2015 primarily from additional wells added to our Pittsburgh Mills gathering system. Processed volumes for the first three months of 2016 decreased 12% from the first three months of 2015 due to declines in existing volumes. NGLs sold decreased 9% from the comparative period due to less volume to process at our plants.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On April 8, 2016, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on April 10, 2020. The amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount. We are charged a commitment fee on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. With each amendment, we pay fees for origination, agency, syndication, and other related fees that are amortized over the life of the credit agreement. With the new amendment, we pledged the following collateral: (a) 85% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties and (b) 100% of our ownership interest in our midstream affiliate, Superior Pipeline Company, L.L.C..

The credit agreement was also amended, among other things, as follows:

At March Subsequent
31, 2016 to

		April 8, 2016	
	(In thousands)		
Maximum credit agreement	\$900,000	\$875,000	
Current elected commitment amount	\$500,000	\$475,000	
Current borrowing base	\$550,000	\$475,000	
Commitment fee	0.375% to 0.50 %	0.50 %	%
LIBOR applicable margin	1.75% to 2.50%	2.00% to 3.00%	
Floating rate applicable margin	0.75% to 1.50%	1.00% to 2.00%	
Origination, agency, syndication, and other related fees incurred to date	\$2,600	\$1,000	

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

Lender	Participation Interest	
BOK (BOKF, NA, dba Bank of Oklahoma)	17	%
Compass Bank	17	%
BMO Harris Financing, Inc.	15	%
Bank of America, N.A.	15	%
Comerica Bank	8	%
Wells Fargo Bank, N.A.	8	%
Canadian Imperial Bank of Commerce	8	%
Toronto Dominion (New York), LLC	8	%
The Bank of Nova Scotia	4	%
	100	%

The borrowing base amount—which is subject to redetermination by the lenders on April 1st and October 1st of each year—is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a 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 credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus the applicable margin 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 credit agreement that cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At March 31, 2016 and April 22, 2016, borrowings were \$260.2 million and \$263.0 million, respectively.

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, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

Currently, the 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; and
- 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.

The 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.

Through the quarter ending March 31, 2019, the credit agreement also requires that we have at the end of each quarter:

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a senior indebtedness ratio of senior indebtedness to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four quarters of no greater than 2.75 to 1.

Beginning with the quarter ending June 30, 2019, and for each quarter ending thereafter, the credit agreement requires:

a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

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As of March 31, 2016, we were in compliance with the covenants in the credit agreement.

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

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for the issuance of the Notes. The Guarantors are all 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 independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

Before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of March 31, 2016.

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 involved, all of which provide us with flexibility in deciding when and if to incur these costs. We completed drilling eight gross wells (4.99 net wells) in the first three months of 2016 compared to 21 gross wells (14.37 net wells) in the first three months of 2015. Capital expenditures for oil and gas properties on the full cost method for the first three months of 2016 by this segment, excluding a \$28.4 million reduction in the ARO liability, totaled \$44.7 million. Capital expenditures for the first three months of 2015, excluding a \$6.1 million reduction in the ARO liability, totaled \$88.0 million.

Currently we plan to participate in drilling approximately 15 to 25 gross wells in 2016 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment range from approximately \$109.0 million to

\$131.0 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. In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment. During the first quarter of 2015, we sold one of these rigs to an unaffiliated third party.

During the first quarter of 2015, we had two BOSS drilling rigs placed into service for third-party operators. The long lead time components for three additional BOSS drilling rigs were ordered in 2014 in anticipation for future demand of the BOSS drilling rigs. However, with the decline in the drilling market, many of these long lead time components were either postponed for later delivery or canceled altogether. Currently, we do not have any contracts to build new BOSS drilling rigs.

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Our estimated 2016 capital expenditures for this segment range from \$9.0 million to \$11.0 million. At March 31, 2016, we had commitments to purchase approximately \$6.4 million for drilling equipment over the next two years. We have spent \$2.9 million for capital expenditures during the first quarter of 2016, compared to \$45.9 million for capital expenditures, including \$30.6 million for the BOSS drilling rigs, during the first quarter of 2015.

Mid-Stream Acquisitions and Capital Expenditures. At our Hemphill Texas system, total processing capacity is 135 MMcf per day and for the first quarter of 2016, our total throughput volume averaged 72.1 MMcf per day.

In the Mississippian play in north central Oklahoma, our Bellmon gathering system throughput volume averaged approximately 36.2 MMcf per day for the first quarter of 2016. During the first quarter of 2016, we connected five additional wells to this gathering system. This processing facility has a total processing capacity of approximately 90 MMcf per day.

In Southeast Texas, our Segno gathering facility, averaged approximately 85 MMcf per day of throughput for the quarter. We connected two new wells to this gathering system in the quarter. Our total gathering capacity for this system is 120 MMcf per day.

In the Appalachian region, at our Pittsburgh Mills gathering system, our average throughput volume for the quarter was 92.3 MMcf per day. Two new well pads were connected during the quarter. In February, we connected the Kane well pad which included five new wells. In March, we connected the Gulick well pad which also included five new wells. This well pad is located on the southern portion of the gathering system. We anticipate two additional well pads to be connected this year. These new pads are expected to be connected in the third quarter of 2016.

Also in the Appalachian area, at our new Snow Shoe gathering system, we connected three new wells during the quarter. Our average throughput volume for the quarter was approximately 7.1 MMcf per day. We are in the process of connecting additional wells from another producer to this system. These new wells will be connected in the second quarter of 2016.

During the first three months of 2016, our mid-stream segment incurred \$2.7 million in capital expenditures as compared to \$7.7 million in the first three months of 2015. For 2016, our estimated capital expenditures range from \$22.0 million to \$24.0 million.

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Contractual Commitments

At March 31, 2016, 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⁾	\$1,153,735	\$48,752	\$97,504	\$352,170	\$655,309
Operating leases ⁽²⁾	6,630	5,036	1,440	154	—
Capital lease interest and maintenance ⁽³⁾	11,474	2,584	4,724	4,090	76
Drill pipe, drilling components, and equipment purchases ⁽⁴⁾	6,401	2,514	3,887	—	—
Enterprise Resource Planning software obligations ⁽⁵⁾	1,911	1,425	486	—	—
Total contractual obligations	\$1,180,151	\$60,311	\$108,041	\$356,414	\$655,385

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our March 31, 2016 interest rates of 6.625% for the Notes and 2.2% for the credit agreement. Our credit agreement has a maturity date of April 10, 2020.

(2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, 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 \$9.0 million and \$2.5 million, respectively.

(4) We have committed to pay \$6.4 million for drilling rig components, drill pipe, and related equipment over the next two years.

(5) We have committed to pay \$1.4 million for Enterprise Resource Planning software and \$0.5 million for maintenance for one year following implementation.

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At March 31, 2016, 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⁾	\$4,381	Unknown	Unknown	Unknown	Unknown
Separation benefit plans ⁽²⁾	\$8,301	\$ 4,594	Unknown	Unknown	Unknown
Asset retirement liability ⁽³⁾	\$70,759	\$ 3,499	\$ 42,031	\$ 6,698	\$ 18,531
Gas balancing liability ⁽⁴⁾	\$3,805	Unknown	Unknown	Unknown	Unknown
Repurchase obligations ⁽⁵⁾	\$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability ⁽⁶⁾	\$16,735	\$ 7,376	\$ 3,299	\$ 1,284	\$ 4,776
Capital leases obligations ⁽⁷⁾	\$21,592	\$ 3,584	\$ 7,613	\$ 9,892	\$ 503
Other	\$410	Unknown	\$ 410	Unknown	Unknown

(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. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under "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. 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 \$4,000 during the first quarter of 2015 but did not have any for the first quarter of 2016.

- (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 our mid-stream segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production.

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Commodity Derivatives. Our commodity derivatives are intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. At March 31, 2016, based on our first quarter 2016 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Q2	Q3	Q4	
	2016	2016	2016	2017
Daily oil production	66 %	32 %	32 %	9 %
Daily natural gas production	63 %	63 %	63 %	16 %

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

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our March 31, 2016 evaluation, we believe the risk of non-performance by our counterparties is not material. At March 31, 2016, the fair values of the net assets we had with each of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2016 (In millions)
Canadian Imperial Bank of Commerce	\$ 8.6
Bank of Montreal	3.8
Bank of America Merrill Lynch	1.4
Scotiabank	0.9
Total assets	\$ 14.7

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At March 31, 2016, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of \$13.9 million and \$0.9 million, respectively, and non-current derivative liabilities of \$0.2 million. At March 31, 2015, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of \$26.7 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 on derivatives in our Unaudited Condensed Consolidated Statements of Operations. These gains at March 31 are as follows:

	Three Months Ended March 31, 2016 2015 (In thousands)	
Gain on derivatives:		
Gain on derivatives, included are amounts settled during the period of \$7,140 and \$11,012, respectively	\$10,929	\$6,586
	\$10,929	\$6,586

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Stock and Incentive Compensation

During the first three months of 2016, we granted awards covering 638,951 shares of restricted stock. These awards had an estimated fair value as of their grant date of \$3.4 million. Compensation expense will be recognized over the three year vesting periods, and during the three months of 2016, we recognized \$0.1 million in compensation expense and capitalized less than \$0.1 million for these awards. During the first three months of 2016, we recognized compensation expense of \$3.3 million for all of our restricted stock, stock options, and SAR grants and capitalized \$0.8 million of compensation cost for oil and natural gas properties.

During the first three months of 2015 we granted awards covering 724,442 shares of restricted stock. These awards had an estimated fair value as of their grant date of \$24.7 million. Compensation expense will be recognized over the three year vesting periods, and during the three months of 2015, we recognized \$0.9 million in compensation expense and capitalized \$0.2 million for these awards. During the first three months of 2015, we recognized compensation expense of \$4.3 million for all of our restricted stock, stock options, and SAR grants and capitalized \$0.9 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 15 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 each of the first three months of 2016 and 2015, the total we received for all of these fees was \$0.1 million. Our proportionate share of assets, liabilities, and net income (loss) relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

Compensation—Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB has issued ASU 2016-09. The amendments are intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public companies, the amendments are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption of the amendments is permitted. The amendments primarily impact classification within the statement of cash flows between financial and operating activities.

Leases. The FASB has issued ASU 2016-02. Under the new guidance, lessees will be required to recognize at the commencement date a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use a specified asset for the lease term. Lessor accounting is largely unchanged. For public companies, the amendments are effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. Early adoption of the amendments is permitted. We are in the process of evaluating the impact it will have on our financial statements.

Income Taxes: Balance Sheet Classification of Deferred Taxes. The FASB has issued ASU 2015-17. This changes how deferred taxes are classified on organizations' balance sheets. Organizations will be required to classify all deferred tax assets

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and liabilities as noncurrent. The amendments apply to all organizations that present a classified balance sheet. For public companies, the amendments are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption of the amendments is permitted. The amendments will require current deferred tax assets to be combined with noncurrent deferred tax assets.

Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs. The FASB has issued ASU 2015-03. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The FASB has also issued ASU 2015-15. The amendments in this ASU allow an entity to defer and present debt issuance cost as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. We have maintained debt issuance costs associated with our credit agreement as an asset and amortize these fees over the life of the credit agreement. For public business entities, the amendments are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments should be applied on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. We have adopted these amendments this quarter. Previously, debt issuance costs associated with the Notes was classified as a long-term asset on the balance sheet, but with ASU 2015-03, it is presented as a direct deduction from the carrying amount of the recognized debt liability.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In April 2016, the FASB issued ASU 2016-10, "Identifying Performance Obligations and Licensing," which amends the revenue guidance on identifying performance obligations and accounting for licenses of intellectual property. On April 1, 2015, the FASB proposed deferring the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. We are in the process of evaluating the impact it will have on our financial statements.

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Results of Operations

Quarter Ended March 31, 2016 versus Quarter Ended March 31, 2015

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

	Quarter Ended March 31,		Percent
	2016	2015	Change (1)
(In thousands unless otherwise specified)			
Total revenue	\$136,184	\$255,099	(47)%
Net loss	\$(41,149)	\$(248,354)	(83)%
Oil and Natural Gas:			
Revenue	\$58,274	\$106,069	(45)%
Operating costs excluding depreciation, depletion, amortization, and impairment	\$33,346	\$45,211	(26)%
Depreciation, depletion, and amortization	\$31,832	\$77,118	(59)%
Impairment of oil and natural gas properties	\$37,829	\$400,593	(91)%
Average oil price received (Bbl)	\$32.50	\$48.47	(33)%
Average NGLs price received (Bbl)	\$6.59	\$8.65	(24)%
Average natural gas price received (Mcf)	\$1.87	\$2.94	(36)%
Oil production (Bbl)	803,000	1,098,000	(27)%
NGLs production (Bbl)	1,291,000	1,286,000	— %
Natural gas production (Mcf)	14,522,000	16,398,000	(11)%
Depreciation, depletion, and amortization rate (Boe)	\$6.72	\$14.76	(54)%
Contract Drilling:			
Revenue	\$38,710	\$95,077	(59)%
Operating costs excluding depreciation	\$28,098	\$51,746	(46)%
Depreciation	\$12,195	\$15,013	(19)%
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	20.6	50.1	(59)%
Average dayrate on daywork contracts	\$18,392	\$20,130	(9)%
Mid-Stream:			
Revenue	\$39,200	\$53,953	(27)%
Operating costs excluding depreciation and amortization	\$31,066	\$44,175	(30)%
Depreciation and amortization	\$11,459	\$10,694	7 %
Gas gathered—Mcf/day	383,405	334,278	15 %
Gas processed—Mcf/day	167,048	189,160	(12)%
Gas liquids sold—gallons/day	519,433	568,876	(9)%
Corporate and other:			
General and administrative expense	\$8,715	\$9,370	(7)%
Gain on disposition of assets	\$192	\$545	(65)%
Other income (expense):			
Interest expense, net	\$(9,617)	\$(7,240)	33 %
Gain on derivatives	\$10,929	\$6,586	66 %

Other	\$(15)	\$(2)	NM
Income tax benefit	\$(15,718)	\$(150,578)	(90)%
Average long-term debt outstanding	\$872,425	\$846,077	3 %
Average interest rate	5.7 %	5.7 %	— %

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

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Oil and Natural Gas

Oil and natural gas revenues decreased \$47.8 million or 45% in the first quarter of 2016 as compared to the first quarter of 2015 primarily due to lower oil, NGLs, and natural gas prices and to a lesser extent from reduced production volumes. In the first quarter of 2016, as compared to the first quarter of 2015, oil production decreased 27%, natural gas production decreased 11%, and NGLs production was essentially unchanged. Average oil prices decreased 33% to \$32.50 per barrel, average natural gas prices decreased 36% to \$1.87 per Mcf, and NGLs prices decreased 24% to \$6.59 per barrel.

Oil and natural gas operating costs decreased \$11.9 million or 26% between the comparative first quarters of 2016 and 2015 due to lower LOE, saltwater disposal expense, and general and administrative expenses offset partially by higher gross production taxes due to fewer credits.

Depreciation, depletion, and amortization ("DD&A") decreased \$45.3 million or 59% due primarily to a 54% decrease in our DD&A rate and a 12% decrease in equivalent production. The decrease in our DD&A rate in the first quarter of 2016 compared to the first quarter of 2015 resulted primarily from the effect of the ceiling test write-downs throughout 2015. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

During the first quarter of 2015, we recorded a non-cash ceiling test write-down of \$400.6 million pre-tax (\$249.4 million, net of tax). During the first quarter of 2016, we recorded a non-cash ceiling test write-down of \$37.8 million pre-tax (\$23.5 million, net of tax).

Contract Drilling

Drilling revenues decreased \$56.4 million or 59% in the first quarter of 2016 versus the first quarter of 2015. The decrease was due primarily to a 59% decrease in the average number of drilling rigs in use as well as a 9% decrease in the average dayrate. Average drilling rig utilization decreased from 50.1 drilling rigs in the first quarter of 2015 to 20.6 drilling rigs in the first quarter of 2016. Revenue on contracts that terminated early were \$2.6 million in the first quarter of 2016 compared to \$12.7 million in the first quarter of 2015.

Drilling operating costs decreased \$23.6 million or 46% between the comparative first quarters of 2016 and 2015. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased \$2.8 million or 19% also due primarily to fewer drilling rigs operating.

Mid-Stream

Our mid-stream revenues decreased \$14.8 million or 27% in the first quarter of 2016 as compared to the first quarter of 2015 due primarily from the average price for natural gas, liquids, and condensate sold decreasing 32%, 33%, and 41%, respectively and from gas sales, liquids, and condensate volumes decreasing 11%, 8%, and 3%, respectively, offset partially by an increase in transportation revenue. Gas processing volumes per day decreased 12% between the comparative quarters primarily due to declines in existing volumes. Gas gathering volumes per day increased 15% between the comparative quarters primarily due to additional wells added to our Pittsburgh Mills gathering system.

Operating costs decreased \$13.1 million or 30% in the first quarter of 2016 compared to the first quarter of 2015 primarily due to a 37% decrease in prices paid for natural gas purchased and an 11% decrease in purchase volumes along with an 8% decrease in field direct expenses. Depreciation and amortization increased \$0.8 million, or 7%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

General and administrative expenses decreased \$0.7 million or 7% in the first quarter of 2016 compared to the first quarter of 2015 primarily due to lower employee costs and a reduction to our workforce during the first quarter of 2016.

Gain on Disposition of Assets

There was a \$0.2 million gain on disposition of assets in the first quarter of 2016 primarily due to the sale of various rig components (including a top drive), vehicles, and a drilling yard in the first quarter of 2016, compared to a gain of \$0.5 million

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for the disposition of assets in the first quarter of 2015 primarily due to the sale of various rig components, vehicles, and to a lesser extent the sale of one drilling rig.

Other Income (Expense)

Interest expense, net of capitalized interest, increased \$2.4 million between the comparative first quarters of 2016 and 2015 due primarily to decreased capitalized interest in the first quarter of 2016 and to a lesser extent to the higher average bank debt outstanding. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the first quarter of 2016 was \$4.0 million compared to \$5.9 million in the first quarter of 2015, and was netted against our gross interest of \$13.6 million and \$13.2 million for the first quarters of 2016 and 2015, respectively. Our average interest rate remained the same at 5.7% and our average debt outstanding was \$26.3 million higher in the first quarter of 2016 as compared to the first quarter of 2015 primarily due to the increase in outstanding borrowings under our credit agreement over the comparative periods.

Gain on derivatives increased \$4.3 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax benefit decreased \$134.9 million between the comparative first quarters of 2016 and 2015 primarily due to decreased pre-tax loss primarily from the decrease in the non-cash ceiling test write-down. Our effective tax rate was 27.6% for the first quarter of 2016 compared to 37.8% for the first quarter of 2015. This decrease is primarily due to increased deferred tax expense in the first quarter of 2016 related to our restricted stock vestings in the first quarter of 2016 after the exhaustion of our remaining accumulated excess tax benefits. There was no current income tax expense in the first quarter of 2016 compared to \$0.1 million for the first quarter of 2015. We did not pay any income taxes in the first quarter of 2016.

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 in the future are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” and similar 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;
- the number of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;

- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;

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expansion and growth of our business and operations;
demand for our drilling rigs and drilling rig rates;
our belief that the final outcome of our legal proceedings will not materially affect our financial results;
our ability to timely secure third-party services used in completing our wells;
our ability to transport or convey our oil 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;
the number of wells our oil and natural gas segment plans to drill during the year; and
our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may be required to record in future periods.

These statements are based on certain assumptions and analyses made by us in light of 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;
decreases or increases in commodity prices; and
other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

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

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Our operations are exposed to market risks primarily because of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, these prices have fluctuated and we expect this to continue. The prices for oil, NGLs, and natural gas also affect the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first three months 2016 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 \$462,000 per month (\$5.5 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 \$258,000 per month (\$3.1 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 \$411,000 per month (\$4.9 million annualized) change in our pre-tax operating cash flow.

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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 March 31, 2016, we had the following derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Apr' 16 – Dec' 16	Natural gas – swap	45,000 MMBtu/day	\$2.596	IF – NYMEX (HH)
Jan' 17 – Dec' 17	Natural gas – swap	10,000 MMBtu/day	\$2.795	IF – NYMEX (HH)
Apr' 16 – Dec' 16	Natural gas – collar	42,000 MMBtu/day	\$2.40 - \$2.88	IF – NYMEX (HH)
Apr' 16 – Dec' 16	Natural gas – three-way collar	13,500 MMBtu/day	\$2.70 - \$2.20 - \$3.26	IF – NYMEX (HH)
Jan' 17 – Dec' 17	Natural gas – three-way collar	15,000 MMBtu/day	\$2.50 - \$2.00 - \$3.32	IF – NYMEX (HH)
Apr' 16 – Jun' 16	Crude oil – collar	5,150 Bbl/day	\$40.71 - \$49.88	WTI – NYMEX
Jul' 16 – Dec' 16	Crude oil – collar	1,450 Bbl/day	\$47.50 - \$56.40	WTI – NYMEX
Apr' 16 – Dec' 16	Crude oil – three-way collar	700 Bbl/day	\$46.50 - \$35.00 - \$57.00	WTI – NYMEX
Jul' 16 – Dec' 16	Crude oil – three-way collar ⁽¹⁾	700 Bbl/day	\$47.50 - \$35.00 - \$63.50	WTI – NYMEX
Jan' 17 – Dec' 17	Crude oil – three-way collar	750 Bbl/day	\$50.00 - \$37.50 - \$63.90	WTI – NYMEX

(1) We pay our counterparty a premium, which can be and is being deferred until settlement.

After March 31, 2016, we entered into the following derivatives:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan' 17 – Dec' 17	Natural gas – swap	20,000 MMBtu/day	\$2.960	IF – NYMEX (HH)
Jan' 17 – Oct' 17	Natural gas – collar	10,000 MMBtu/day	\$2.75 - \$2.95	IF – NYMEX (HH)
Jul' 16 – Sep' 16	Crude oil – collar	1,000 Bbl/day	\$40.00 - \$46.75	WTI – NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement 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 agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first three months of 2016, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately \$2.2 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

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 Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of March 31, 2016 in ensuring the appropriate information 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 Chief Executive Officer, Chief Financial Officer, and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended March 31, 2016 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, as defined in Rule 13a – 15(f) under the Exchange Act.

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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 in this case 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 that was 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 located in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. In July 2014, a second class certification hearing was held where, in addition to 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.

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, 2015, 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, 2015.

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

The following table provides information relating to our repurchase of common stock for the three months ended March 31, 2016:

Period	(a) Total Number of Shares Purchased ⁽¹⁾	(b) Average Price Paid Per Share ⁽²⁾	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs ⁽¹⁾	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2016 to January 31, 2016	—	\$ —	—	—
February 1, 2016 to February 29, 2016	—	—	—	—
March 1, 2016 to March 31, 2016	152,060	9.02	152,060	—
Total	152,060	\$ 9.02	152,060	—

The shares were repurchased to remit withholding of taxes on the value of stock distributed with the first quarter (1) 2016 vesting of restricted stock for grants previously made from our “Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015.”

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

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibits:

- 15 Letter re: Unaudited Interim Financial Information.
- 31.1 Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act.
- 31.2 Certification of Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act.
- 32 Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
- 101.INS XBRL Instance Document.
- 101.SCH XBRL Taxonomy Extension Schema Document.
- 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document.
- 101.DEF XBRL Taxonomy Extension Definition Linkbase Document.
- 101.LAB XBRL Taxonomy Extension Labels Linkbase Document.
- 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Unit Corporation

Date: May 5, 2016 By: /s/ Larry D. Pinkston
LARRY D. PINKSTON
Chief Executive Officer and Director

Date: May 5, 2016 By: /s/ David T. Merrill
DAVID T. MERRILL
Senior Vice President, Chief Financial Officer,
and Treasurer