UNIT CORP
Form 10-Q
November 03, 2016
Table of Contents

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 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.)

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 [x] No [ ]

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

As of October 21, 2016, 51,486,818 shares of the issuer's common stock were outstanding.

Table of Contents

TABLE OF CONTENTS

		Page Number
	PART I. Financial Information	
Item 1.	Financial Statements (Unaudited)	
	Unaudited Condensed Consolidated Balance Sheets September 30, 2016 and December 31, 2015	4
	Unaudited Condensed Consolidated Statements of Operations Three and Nine Months Ended September 30, 2016 and 2015	6
	Unaudited Condensed Consolidated Statements of Cash Flows Nine Months Ended September 30, 2016 and 2015	7
	Notes to Unaudited Condensed Consolidated Financial Statements	8
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	26
Item 3.	Quantitative and Qualitative Disclosure About Market Risk	50
Item 4.	Controls and Procedures	51
	PART II. Other Information	
Item 1.	Legal Proceedings	51
Item 1A.	Risk Factors	51
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	52
Item 3.	Defaults Upon Senior Securities	52
Item 4.	Mine Safety Disclosures	52
Item 5.	Other Information	52
Item 6.	Exhibits	53
Signatures		54

Table of Contents

Forward-Looking Statements

This report contains “forward-looking statements” – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document that addresses activities, events or developments we expect or anticipate will or may occur 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;
- 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;
- our financial condition and liquidity;
- the number of wells our oil and natural gas segment plans to drill or rework during the year; and
- our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may 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;
- changes in the current geopolitical situation;

- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- our ability to successfully implement our pending technology conversion process relating to our financial and operational information systems; 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

Table of Contents

make to forward-looking statements to reflect events or circumstances after the date of this document to reflect unanticipated events.

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2016	December 31, 2015
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 913	$ 835
Accounts receivable, net of allowance for doubtful accounts of $5,174 and $5,199 at September 30, 2016 and December 31, 2015, respectively	71,955	79,941
Materials and supplies	3,334	3,565
Current derivative asset (Note 10)	—	10,186
Current income tax receivable	366	21,002
Current deferred tax asset	8,361	14,206
Assets held for sale	—	615
Prepaid expenses and other	8,717	9,908
Total current assets	93,646	140,258
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,434,782	5,401,618
Unproved properties not being amortized	322,992	337,099
Drilling equipment	1,568,053	1,567,560
Gas gathering and processing equipment	700,170	689,063
Saltwater disposal systems	60,554	60,316
Corporate land and building	58,767	49,890
Transportation equipment	33,168	40,072
Other	47,282	45,489
	8,225,768	8,191,107
Less accumulated depreciation, depletion, amortization, and impairment	5,915,369	5,609,980
Net property and equipment	2,310,399	2,581,127
Goodwill	62,808	62,808
Non-current derivative asset (Note 10)	177	968
Other assets	14,161	14,681
Total assets	$ 2,481,191	$ 2,799,842

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

Table of Contents

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

	September 30, 2016	December 31, 2015
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 56,375	$ 87,413
Accrued liabilities (Note 5)	57,719	46,918
Current derivative liability (Note 10)	5,552	—
Current portion of other long-term liabilities (Note 6)	16,342	16,560
Total current liabilities	135,988	150,891
Long-term debt less debt issuance costs (Note 6)	854,583	918,995
Non-current derivative liability (Note 10)	265	285
Other long-term liabilities (Note 6)	103,657	140,341
Deferred income taxes	197,122	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, 51,496,833 and 50,413,101 shares issued as of September 30, 2016 and December 31, 2015, respectively	10,016	9,831
Capital in excess of par value	499,689	486,571
Retained earnings	679,871	817,178
Total shareholders' equity	1,189,576	1,313,580
Total liabilities and shareholders' equity	$ 2,481,191	$ 2,799,842

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

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$78,854	$96,619	$206,318	$309,944
Contract drilling	25,819	65,022	88,786	215,114
Gas gathering and processing	48,735	50,752	132,793	156,881
Total revenues	153,408	212,393	427,897	681,939
Expenses:				
Oil and natural gas:				
Operating costs	26,014	38,688	92,691	129,871
Depreciation, depletion, and amortization	27,135	57,159	89,378	202,378
Impairment of oil and natural gas properties (Note 2)	49,443	329,924	161,563	1,141,053
Contract drilling:				
Operating costs	19,137	35,486	66,489	123,717
Depreciation	11,318	14,255	34,431	42,533
Impairment of contract drilling equipment (Note 3)	—	—	—	8,314
Gas gathering and processing:				
Operating costs	35,738	40,314	99,185	125,081
Depreciation and amortization	11,436	10,976	34,410	32,518
General and administrative	8,932	7,643	26,029	26,637
(Gain) loss on disposition of assets	(154)	7,230	(823)	6,270
Total operating expenses	188,999	541,675	603,353	1,838,372
Loss from operations	(35,591)	(329,282)	(175,456)	(1,156,433)
Other income (expense):				
Interest, net	(10,002)	(8,286)	(30,225)	(23,482)
Gain (loss) on derivatives	6,969	8,250	(4,774)	12,917
Other, net	3	16	(11)	38
Total other income (expense)	(3,030)	(20)	(35,010)	(10,527)
Loss before income taxes	(38,621)	(329,302)	(210,466)	(1,166,960)
Income tax expense (benefit):				
Current	—	(2,584)	—	(1,716)
Deferred	(14,599)	(121,437)	(73,159)	(437,220)
Total income taxes	(14,599)	(124,021)	(73,159)	(438,936)
Net loss	$(24,022)	$(205,281)	$(137,307)	$(728,024)
Net loss per common share:				
Basic	$(0.48)	$(4.18)	$(2.75)	$(14.83)
Diluted	$(0.48)	$(4.18)	$(2.75)	$(14.83)

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

Table of Contents

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

	Nine Months Ended September 30, 2016	2015
	(In thousands)	
OPERATING ACTIVITIES:		
Net loss	$(137,307)	$(728,024)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, and amortization	160,023	279,739
Impairments (Notes 2 and 3)	161,563	1,149,367
(Gain) loss on derivatives	4,774	(12,917)
Cash receipts on derivatives settled	11,735	32,156
Deferred tax benefit	(73,159)	(437,220)
(Gain) loss on disposition of assets	(1,100)	6,270
Employee stock compensation plans	10,664	12,514
Other, net	(3,055)	1,834
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	759	84,098
Accounts payable	26,940	(4,432)
Material and supplies	231	(2,114)
Accrued liabilities	14,073	(363)
Income taxes	20,636	(4,975)
Other, net	985	5,549
Net cash provided by operating activities	197,762	381,482
INVESTING ACTIVITIES:		
Capital expenditures	(154,558)	(484,028)
Proceeds from disposition of assets	46,880	9,838
Other	169	—
Net cash used in investing activities	(107,509)	(474,190)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	195,700	484,600
Payments under credit agreement	(261,700)	(388,900)
Payments on capitalized leases	(2,756)	(2,648)
Tax (benefit) expense from stock compensation	(376)	4
Book overdrafts	(21,043)	(503)
Net cash (used in) provided by financing activities	(90,175)	92,553
Net increase (decrease) in cash and cash equivalents	78	(155)
Cash and cash equivalents, beginning of period	835	1,049
Cash and cash equivalents, end of period	$913	$894

Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	16,650	12,691
Income taxes	—	3,277
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	36,934	116,062
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	29,423	8,558

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

7

Table of Contents

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 September 30, 2016 and December 31, 2015;
- Statements of Operations for the three and nine months ended September 30, 2016 and 2015; and
- Statements of Cash Flows for the nine months ended September 30, 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 nine months ended September 30, 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. There was no impact to consolidated net income (loss) or shareholders' equity.

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 each quarter for the nine months ended September 30, 2015, the 12-month average commodity prices decreased, resulting in a non-cash ceiling test write-down of $400.6 million pre-tax ($249.4 million, net of tax), $410.5 million pre-tax ($255.6 million, net of tax), and $329.9 million pre-tax ($205.4 million, net of tax) for the first, second, and third quarters, respectively.

During each quarter for the nine months ended September 30, 2016, the 12-month average commodity prices decreased, resulting in a non-cash ceiling test write-down of $37.8 million pre-tax ($23.5 million, net of tax), $74.3 million pre-tax ($46.3 million, net of tax), and $49.4 million pre-tax ($30.8 million, net of tax) for the first, second, and third quarters, respectively.

Table of Contents

NOTE 3 – DIVESTITURES

Oil and Natural Gas

We sold non-core oil and natural gas assets, net of related expenses, for $43.6 million during the first nine months of 2016, compared to $0.2 million during the first nine months of 2015. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling

During the second quarter of 2015, we recorded a write-down of approximately $8.3 million pre-tax on drilling equipment being held for sale. During the third quarter of 2015, we sold 30 drilling rigs and other drilling equipment at auction. The proceeds from that sale, less costs to sell, was less than the $11.0 million net book value resulting in a loss of $7.3 million pre-tax.

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 September 30, 2016			
Basic loss per common share	$(24,022)	50,081	$ (0.48)
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	—	—
Diluted loss per common share	$(24,022)	50,081	$ (0.48)
For the three months ended September 30, 2015			
Basic loss per common share	$(205,281)	49,155	$ (4.18)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted loss per common share	$(205,281)	49,155	$ (4.18)

Due to the net loss for the three months ended September 30, 2016, approximately 546,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and excluded from the above loss per share calculation. For the three months ended September 30, 2015, approximately 296,000 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 September 30,	
	2016	2015
Stock options and SARs	240,270	261,270
Average exercise price	$49.29	$ 50.34

9

Table of Contents

	Loss (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2016			
Basic loss per common share	$(137,307)	50,012	$(2.75)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted loss per common share	$(137,307)	50,012	$(2.75)
For the nine months ended September 30, 2015			
Basic loss per common share	$(728,024)	49,094	$(14.83)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted loss per common share	$(728,024)	49,094	$(14.83)

Because of the net loss for the nine months ended September 30, 2016, approximately 424,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and excluded from the above loss per share calculation. For the nine months ended September 30, 2015, approximately 204,000 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:

	Nine Months Ended September 30,	
	2016	2015
Stock options and SARs	240,270	261,270
Average exercise price	$49.29	$50.34

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Interest payable	$17,247	$ 6,321
Lease operating expenses	12,751	17,220
Taxes	10,717	3,767
Employee costs	11,718	12,641
Third-party credits	2,831	3,326
Derivative settlements	26	—
Other	2,429	3,643
Total accrued liabilities	$57,719	$ 46,918

Table of Contents

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:

	September 30, 2016	December 31, 2015
	(In thousands)	
Credit agreement with an average interest rate of 2.5% and 2.6% at September 30, 2016 and December 31, 2015, respectively	$215,000	$ 281,000
6.625% senior subordinated notes due 2021	650,000	650,000
Total principal amount	865,000	931,000
Less: unamortized discount	(2,941)	(3,338)
Less: debt issuance costs, net	(7,476)	(8,667)
Total long-term debt	$854,583	$ 918,995

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 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 $875.0 million. Our elected commitment amount is $475.0 million. Our borrowing base is $475.0 million. We are charged a commitment fee of 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 $1.0 million in origination, agency, syndication, and other related fees. We are amortizing these fees 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 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. The October 2016 redetermination did not result in any changes. 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 2.00% to 3.00% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the 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 September 30, 2016, we had $215.0 million of outstanding borrowings under our credit agreement.

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

Table of Contents

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:

- 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.

As of September 30, 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) outstanding. Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021. In issuing the Notes, we incurred fees of $14.7 million that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms of and providing for the issuance of the Notes. The Guarantors are most of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the 2011 Indenture. 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.

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 September 30, 2016.

Table of Contents

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Asset retirement obligation (ARO) liability	$71,021	$ 98,297
Capital lease obligations	19,818	22,466
Workers' compensation	15,185	16,551
Separation benefit plans	5,289	9,886
Deferred compensation plan	4,470	4,244
Gas balancing liability	3,806	5,047
Other	410	410
	119,999	156,901
Less current portion	16,342	16,560
Total other long-term liabilities	$103,657	$ 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 October 1, 2016 (and through 2021) are $16.3 million, $44.7 million, $9.4 million, $223.9 million, and $656.7 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 $3.7 million is included in current portion of other long-term liabilities and the non-current portion of $16.2 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of September 30, 2016. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are $8.1 million and $2.1 million, respectively at September 30, 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 their fair market value at that time.

Future payments required under the capital leases at September 30, 2016:

Ending September 30,	Amount (In thousands)
2017	$ 6,168
2018	6,168
2019	6,168
2020	6,168
2021	5,311
Total future payments	29,983
Less payments related to:	
Maintenance	8,106
Interest	2,059
Present value of future minimum payments	$ 19,818

13

Table of Contents

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:

	Nine Months Ended September 30,	
	2016	2015
	(In thousands)	
ARO liability, January 1:	$98,297	$100,567
Accretion of discount	2,147	2,599
Liability incurred	311	6,505
Liability settled	(874)	(1,933)
Liability sold [1]	(10,758)	(249)
Revision of estimates [2]	(18,102)	(12,881)
ARO liability, September 30:	71,021	94,608
Less current portion	3,498	3,481
Total long-term ARO	$67,523	$91,127

____

(1) We sold our interest in approximately 1,270 non-core wells to unaffiliated third-parties during the first nine months 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

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. The FASB issued ASU 2016-15, to address diversity in how certain transactions are presented and classified in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 31, 2017, and early adoption is permitted. We do not believe this ASU will have a material impact on our financial statements.

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. We do not believe the amendments will have a material impact on our financial statements.

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 these amendments 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

Table of Contents

current deferred tax assets to be combined with noncurrent deferred tax assets. We do not believe the amendments will have a material impact on our financial statements.

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 during the first quarter of 2016. 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.

Presentation of Financial Statements-Going Concern: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The FASB has issued ASU 2014-15. This is intended to define management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern and to provide related footnote disclosures. For each reporting period, management will be required to evaluate whether there are conditions or events that raise substantial doubt about a company's ability to continue as a going concern within one year from the date financial statements are issued. The amendments are effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. Early application is permitted for annual or interim reporting periods for which the financial statements have not previously been issued. We will begin performing the assessments and making any disclosures, if applicable, beginning at the end of fiscal year 2016.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This guidance 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 May 2016, the FASB issued ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients," which provides clarifying guidance in certain areas and adds some practical expedients. Also in May 2016, the FASB issued ASU 2016-11, "Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting." This ASU rescinds SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities— Oil and Gas, effective upon the adoption of Topic 606, Revenue from Contracts with Customers. 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. The FASB has issued 2015-14, which defers the effective date to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. We are in the process of evaluating the impact this guidance will have on our financial statements.

NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Recognized stock compensation expense	$1.9	$2.1	$7.2	$11.2
Capitalized stock compensation cost for our oil and natural gas properties	0.4	0.7	1.6	2.6
Tax benefit on stock based compensation	0.7	0.8	2.7	4.2

Table of Contents

The remaining unrecognized compensation cost related to unvested awards at September 30, 2016 is approximately $8.6 million, of which $1.3 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.7 of a year.

The Second Amended and Restated Unit Corporation Stock and Incentive Compensation Plan effective May 6, 2015 (the amended plan) allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) 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."

We did not grant any SARs or stock options during either of the three or nine month periods ending September 30, 2016 or 2015. We did not grant any restricted stock awards during either of the three month periods ending September 30, 2016 or 2015. The following table shows the fair value of restricted stock awards granted to employees and non-employee directors during the nine month periods ending September 30, 2016 and 2015:

	Nine Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	Time Vested	Performance Vested	Time Vested	Performance Vested
Shares granted:				
Employees	486,578	152,373	576,361	148,081
Non-employee directors	90,000	—	25,848	—
	576,578	152,373	602,209	148,081
Estimated fair value (in millions):(1)				
Employees	$2.6	$ 0.8	$18.5	$ 5.1
Non-employee directors	0.9	—	0.9	—
	$3.5	$ 0.8	$19.4	$ 5.1
Percentage of shares granted expected to be distributed:				
Employees	94 %	89 %	94 %	3 %
Non-employee directors	100 %	N/A	100 %	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 nine 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 200% of the restricted shares granted as performance shares. The second will vest, one-third each year, over a three year vesting period based on the company's achievement of cash flow to total assets 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 nine months of 2016 was $1.3 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 September 30, 2016, our derivative transactions were comprised of 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.

Table of Contents

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

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

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

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

At September 30, 2016, we had the following derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct’16 – Dec’16	Natural gas – swap	45,000 MMBtu/day	$2.596	IF – NYMEX (HH)
Jan’17 – Dec'17	Natural gas – swap	60,000 MMBtu/day	$2.960	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – swap	10,000 MMBtu/day	$3.025	IF – NYMEX (HH)
Jan’17 – Dec'17	Natural gas – basis swap	20,000 MMBtu/day	$(0.215)	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Oct’16 – Dec'16	Natural gas – collar	42,000 MMBtu/day	$2.40 - $2.88	IF – NYMEX (HH)
Jan’17 – Oct'17	Natural gas – collar	20,000 MMBtu/day	$2.88 - $3.10	IF – NYMEX (HH)
Oct’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)
Oct'16 – Dec'16	Crude oil – collar	1,450 Bbl/day	$47.50 - $56.40	WTI – NYMEX
Oct'16 – Dec'16	Crude oil – three-way collar	700 Bbl/day	$46.50 - $35.00 - $57.00	WTI – NYMEX
Oct'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	1,750 Bbl/day	$50.00 - $39.10 - $61.67	WTI – NYMEX

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

After September 30, 2016, we entered into the following derivative transactions:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'16 – Dec'16	Crude oil – collar	2,000 Bbl/day	$48.00 - $53.15	WTI – NYMEX
Jan'17 – Dec'17	Crude oil – three-way collar	2,000 Bbl/day	$49.60 - $40.00 - $60.38	WTI – NYMEX
Jan'17 – Mar'17	Natural gas – swap	10,000 MMBtu/day	$3.550	IF – NYMEX (HH)

Table of Contents

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

	Balance Sheet Location	Derivative Assets Fair Value September 30, 2016 (In thousands)	December 31, 2015
Commodity derivatives:			
Current	Current derivative asset	$—	$ 10,186
Long-term	Non-current derivative asset	177	968
Total derivative assets		$177	$ 11,154

	Balance Sheet Location	Derivative Liabilities Fair Value September 30, 2016 (In thousands)	December 31, 2015
Commodity derivatives:			
Current	Current derivative liability	$ 5,552	$ —
Long-term	Non-current derivative liability	265	285
Total derivative liabilities		$ 5,817	$ 285

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 in our Unaudited Condensed Consolidated Balance Sheets.

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

Derivatives Instruments	Location of Gain Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative 2016 (In thousands)	2015
Commodity derivatives	Gain (loss) on derivatives [1]	$ 6,969	$ 8,250
Total		$ 6,969	$ 8,250

(1) Amounts settled during the 2016 and 2015 periods include a loss of $0.5 million and a gain of $11.1 million, respectively.

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

Derivatives Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative 2016 (In thousands)	2015
Commodity derivatives	Gain (loss) on derivatives [1]	$ (4,774)	$ 12,917
Total		$ (4,774)	$ 12,917

(1) Amounts settled during the 2016 and 2015 periods include gains of $11.7 million and $32.2 million, respectively.

Table of Contents

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.

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:

	September 30, 2016			
	Level 2	Level 3	Effect of Netting	Net Amounts Presented
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$1,206	$714	$(1,743)	$177
Liabilities	(4,719)	(2,841)	1,743	(5,817)
	$(3,513)	$(2,127)	$—	$(5,640)

	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 cash collateral with our counterparties and no collateral has been posted as of September 30, 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.

Table of Contents

Level 3 Fair Value Measurements

Commodity Derivatives. The fair values of our natural gas and crude oil collars and three-way collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

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

	Net Derivatives			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Beginning of period	$(4,761)	$207	$9,094	$3,355
Total gains or losses (realized and unrealized):				
Included in earnings [1]	3,077	4,436	(3,257)	5,324
Settlements	(443)	(2,161)	(7,964)	(6,197)
End of period	$(2,127)	$2,482	$(2,127)	$2,482
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	$2,634	$2,275	$(11,221)	$(873)

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

The following table provides quantitative information about our Level 3 unobservable inputs at September 30, 2016:

Commodity [1]	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil collars	$ 174	Discounted cash flow	Forward commodity price curve	$0.17 - $2.60
Oil three-way collars	$ 533	Discounted cash flow	Forward commodity price curve	$0.00 - $5.82
Natural gas collar	$ (1,730)	Discounted cash flow	Forward commodity price curve	$0.00 - $0.69
Natural gas three-way collars	$ (1,104)	Discounted cash flow	Forward commodity price curve	$0.00 - $0.40

(1) The commodity contracts detailed in this category include non-exchange-traded crude oil and natural gas collars 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 September 30, 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 September 30, 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 September 30, 2016 and December 31, 2015 was $215.0 million and $281.0 million, respectively. This debt would be classified as Level 2.

Table of Contents

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 September 30, 2016 and December 31, 2015 were $639.6 million and $638.0 million, respectively. We estimate the fair value of these Notes using quoted marked prices at September 30, 2016 and December 31, 2015 were $557.8 million and $455.5 million, respectively. These Notes would be classified as Level 2.

Fair Value of Non-Financial Instruments

The initial measurement of AROs at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant, and equipment. Significant Level 3 inputs used in the calculation of AROs include plugging costs and remaining reserve lives. A reconciliation of the Company's AROs is presented in Note 7 – Asset Retirement Obligations.

NOTE 12 – INDUSTRY SEGMENT INFORMATION

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

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

Our oil and natural gas segment is engaged in the 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.

Table of Contents

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

	Three Months Ended September 30, 2016					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$78,854	$—	$ —	$—	$ —	$ 78,854
Contract drilling	—	25,819	—	—	—	25,819
Gas gathering and processing	—	—	63,090	—	(14,355)	48,735
Total revenues	78,854	25,819	63,090	—	(14,355)	153,408
Expenses:						
Oil and natural gas:						
Operating costs	27,710	—	—	—	(1,696)	26,014
Depreciation, depletion, and amortization	27,135	—	—	—	—	27,135
Impairment of oil and natural gas properties	49,443	—	—	—	—	49,443
Contract drilling:						
Operating costs	—	19,137	—	—	—	19,137
Depreciation	—	11,318	—	—	—	11,318
Gas gathering and processing:						
Operating costs	—	—	48,397	—	(12,659)	35,738
Depreciation and amortization	—	—	11,436	—	—	11,436
Total expenses	104,288	30,455	59,833	—	(14,355)	180,221
Total operating income (loss) (1)	(25,434)	(4,636)	3,257	—	—	(26,813)
General and administrative expense	—	—	—	(8,932)	—	(8,932)
Gain on disposition of assets	—	151	—	3	—	154
Gain on derivatives	—	—	—	6,969	—	6,969
Interest expense, net	—	—	—	(10,002)	—	(10,002)
Other	—	—	—	3	—	3
Income (loss) before income taxes	$(25,434)	$(4,485)	$ 3,257	$(11,959)	$ —	$ (38,621)

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

Table of Contents

	Three Months Ended September 30, 2015					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$96,619	$—	$ —	$—	$ —	$ 96,619
Contract drilling	—	68,426	—	—	(3,404)	65,022
Gas gathering and processing	—	—	66,836	—	(16,084)	50,752
Total revenues	96,619	68,426	66,836	—	(19,488)	212,393
Expenses:						
Oil and natural gas:						
Operating costs	39,942	—	—	—	(1,254)	38,688
Depreciation, depletion, and amortization	57,159	—	—	—	—	57,159
Impairment of oil and natural gas properties	329,924	—	—	—	—	329,924
Contract drilling:						
Operating costs	—	38,671	—	—	(3,185)	35,486
Depreciation	—	14,255	—	—	—	14,255
Impairment of contract drilling properties	—	—	—	—	—	—
Gas gathering and processing:						
Operating costs	—	—	55,136	—	(14,822)	40,314
Depreciation and amortization	—	—	10,976	—	—	10,976
Total expenses	427,025	52,926	66,112	—	(19,261)	526,802
Total operating income (loss)[(1)]	(330,406)	15,500	724	—	(227)	(314,409)
General and administrative expense	—	—	—	(7,643)	—	(7,643)
Loss on disposition of assets	—	(7,230)	—	—	—	(7,230)
Gain on derivatives	—	—	—	8,250	—	8,250
Interest expense, net	—	—	—	(8,286)	—	(8,286)
Other	—	—	—	16	—	16
Income (loss) before income taxes	$(330,406)	$8,270	$ 724	$(7,663)	$ (227)	$ (329,302)

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

Table of Contents

	Nine Months Ended September 30, 2016					
	Oil and Natural Gas	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
	(In thousands)					
Revenues:						
Oil and natural gas	$206,318	$—	$ —	$—	$ —	$ 206,318
Contract drilling	—	88,786	—	—	—	88,786
Gas gathering and processing	—	—	168,668	—	(35,875)	132,793
Total revenues	206,318	88,786	168,668	—	(35,875)	427,897
Expenses:						
Oil and natural gas:						
Operating costs	98,070	—	—	—	(5,379)	92,691
Depreciation, depletion, and amortization	89,378	—	—	—	—	89,378
Impairment of oil and natural gas properties	161,563	—	—	—	—	161,563
Contract drilling:						
Operating costs	—	66,489	—	—	—	66,489
Depreciation	—	34,431	—	—	—	34,431
Gas gathering and processing:						
Operating costs	—	—	129,681	—	(30,496)	99,185
Depreciation and amortization	—	—	34,410	—	—	34,410
Total expenses	349,011	100,920	164,091	—	(35,875)	578,147
Total operating income (loss)[1]	(142,693)	(12,134)	4,577	—	—	(150,250)
General and administrative expense	—	—	—	(26,029)	—	(26,029)
Gain (loss) on disposition of assets	(324)	1,467	(302)	(18)	—	823
Loss on derivatives	—	—	—	(4,774)	—	(4,774)
Interest expense, net	—	—	—	(30,225)	—	(30,225)
Other	—	—	—	(11)	—	(11)
Income (loss) before income taxes	$(143,017)	$(10,667)	$ 4,275	$(61,057)	$ —	$ (210,466)

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

Table of Contents

	Nine Months Ended September 30, 2015					
	Oil and Natural Gas (In thousands)	Contract Drilling	Mid-stream	Other	Eliminations	Total Consolidated
Revenues:						
Oil and natural gas	$309,944	$—	$ —	$—	$ —	$309,944
Contract drilling	—	234,177	—	—	(19,063)	215,114
Gas gathering and processing	—	—	209,803	—	(52,922)	156,881
Total revenues	309,944	234,177	209,803	—	(71,985)	681,939
Expenses:						
Oil and natural gas:						
Operating costs	133,502	—	—	—	(3,631)	129,871
Depreciation, depletion, and amortization	202,378	—	—	—	—	202,378
Impairment of oil and natural gas properties	1,141,053	—	—	—	—	1,141,053
Contract drilling:						
Operating costs	—	139,114	—	—	(15,397)	123,717
Depreciation	—	42,533	—	—	—	42,533
Impairment of contract drilling properties	—	8,314	—	—	—	8,314
Gas gathering and processing:						
Operating costs	—	—	174,342	—	(49,261)	125,081
Depreciation and amortization	—	—	32,518	—	—	32,518
Total expenses	1,476,933	189,961	206,860	—	(68,289)	1,805,465
Total operating income (loss) [(1)]	(1,166,989)	44,216	2,943	—	(3,696)	(1,123,526)
General and administrative expense	—	—	—	(26,637)	—	(26,637)
Gain (loss) on disposition of assets	—	(6,735)	465	—	—	(6,270)
Gain on derivatives	—	—	—	12,917	—	12,917
Interest expense, net	—	—	—	(23,482)	—	(23,482)
Other	—	—	—	38	—	38
Income (loss) before income taxes	$(1,166,989)	$37,481	$ 3,408	$(37,164)	$ (3,696)	$(1,166,960)

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

Table of Contents

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

Management’s Discussion and Analysis (MD&A) provides you with an understanding of our operating results and financial condition by focusing on changes in certain key measures from year to year or period to period. 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 information in our most recent Annual Report on Form 10-K in connection with your review of the information below as well as our unaudited condensed consolidated financial statements and related notes.

Unless otherwise indicated or required by the content, when used in this report the terms “company,” “Unit,” “us,” “our,” “we,” and “its” refer to Unit Corporation or, as appropriate, one or more of its subsidiaries.

General

We operate, manage, and analyze the results of our operations through that of 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, our success depends, to a large degree, on the prices we receive for our oil and natural gas production, 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 affect us and our industry.

Deteriorating commodity prices worldwide during the past two years or so brought about significant adverse changes affecting our industry and us. These lower commodity prices caused us (and other oil and gas companies) to reduce (or even stop) drilling activity and spending. When drilling activity and spending decline for extended periods of time the rates for and the number of our drilling rigs working also tend to decline. In addition, sustained lower commodity prices impact the liquidity condition of some of our industry partners and customers, which, in turn, could limit their ability to meet their financial obligations to us.

Commodity prices are volatile and subject to a number of factors most of which we cannot control. We are slowly starting to see signs of improvement. Our oil and natural gas segment began using one drilling rig early in the fourth quarter and we plan on adding two additional rigs later in the fourth quarter. After the quarter end, our contract drilling segment contracted the eighth BOSS drilling rig and was awarded a term contract to build our ninth BOSS rig, with construction expected to be completed in January 2017. In addition, we have seen some indicators that other operators may pick up their activity as well, but the extent of an increase remains to be determined.

Table of Contents

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:

- We incurred non-cash ceiling test write-downs in the first nine months of 2016 of $161.6 million ($100.6 million net of tax). It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. In our Form 10-Q for the second quarter of 2016, we disclosed based on those factors, holding July 1, 2016 prices constant for the remaining months of the third quarter, we did not then anticipate a write-down for the third quarter; however, oil and NGL prices decreased in August and September (from July 2016 prices) resulting in us incurring a $49.4 million ($30.8 million, net of tax) non-cash ceiling test write-down for the third quarter of 2016. Subject to these inherent uncertainties, if we hold these same factors constant as they existed on October 1, 2016 and only adjust the 12-month average price to an estimated fourth quarter ending average (holding October 2016 prices constant for the remaining two months of the fourth quarter of 2016), we would not expect to recognize an impairment in the fourth quarter of 2016. Commodity prices remain volatile and they could negatively impact the 12-month average price and the potential for an impairment in the fourth quarter.
- We reduced the number of gross wells to be drilled in 2016 by approximately 66% from the number drilled in 2015 due to reduced cash flow.
- The decline in drilling by our customers reduced the average utilization of our drilling rig fleet. At December 31, 2015, we had 26 drilling rigs operating and at October 21, 2016, that number was 20. We started to see late in the third quarter and into the fourth quarter of 2016, a small increase in rig activity. We have seen some indicators that operators may pick up their activity, but the extent of an increase remains to be determined. As of September 30, 2016, seven of our eight BOSS drilling rigs were under contract. After the quarter end, we contracted the eighth BOSS drilling rig under a term contract which went to work in October. Additionally, we were awarded a term contract to build our ninth BOSS rig, with construction expected to be completed in January 2017.
- Due to low NGLs prices, we are operating most of our mid-stream processing facilities in full ethane rejection mode which reduces the amount of liquids sold. As long as NGLs prices remain depressed, we expect to continue operating in full ethane rejection mode. Low prices have reduced drilling activity around our systems thus reducing the number of new wells available to connect to our systems which has resulted in lower processed volumes as production from connected wells naturally decline.
- Under the third amendment to our credit agreement entered into on April 8, 2016, the lenders decreased our borrowing base from $550.0 million to $475.0 million. Our commitment under the credit agreement also decreased from $500.0 million to $475.0 million. The October 2016 redetermination did not result in any changes to our borrowing base.

In response to lower commodity prices we did the following during the first nine months of 2016:

- Consolidated from five to two the number of divisions within our drilling segment further reducing the costs associated with operating the divisions.
- Designed the higher end of our 2016 exploration and production segment budget so the majority of those proposed expenditures would be in the latter part of the year allowing us to take into account future commodity price movement before we actually incur those expenditures.
- Implemented certain reductions in our office and field workforces to account for the reduction in our operating activities as well as reducing the compensation paid to drilling personnel.
- Through September 30, 2016, we have sold non-core oil and gas properties for approximately $43.6 million with most of the proceeds being used to pay down borrowings under our bank credit agreement.

Executive Summary

Oil and Natural Gas

Third quarter 2016 production from our oil and natural gas segment was 4,194,000 barrels of oil equivalent (Boe), a decrease of 4% and 17% from the second quarter of 2016 and the third quarter of 2015, respectively. The decrease from the second quarter of 2016 was due primarily to approximately 0.6 Bcfe of production in the Wilcox play being shut in for six days during the third quarter because of maintenance on a third-party operated processing plant. The decrease from the third quarter

Table of Contents

of 2015 was primarily due to natural declines in production with minimal replacement in production from new wells due to our reduced drilling activity resulting from lower commodity prices.

Third quarter 2016 oil and natural gas revenues increased 14% over the second quarter of 2016 and decreased 18% from the third quarter of 2015. The increase over the second quarter of 2016 was due primarily to higher commodity prices offset partially from lower production volumes. The decrease from the third quarter of 2015 was due primarily to lower oil and natural gas prices and to a lesser extent from lower production volumes.

Our oil prices for the third quarter of 2016 increased 3% over the second quarter of 2016 and decreased 16% from the third quarter of 2015. Our NGLs prices increased 11% over the second quarter of 2016 and increased 45% from the third quarter of 2015. Our natural gas prices increased 27% over the second quarter of 2016 and decreased 14% from the third quarter of 2015.

Operating cost per Boe produced for the third quarter of 2016 decreased 19% from both the second quarter of 2016 and from the third quarter of 2015. The decrease from the second quarter of 2016 was primarily due to lower lease operating expenses. The decrease from the third quarter of 2015 was primarily due to lower lease operating expenses, saltwater disposal expense, and general and administrative expenses offset by higher gross production taxes due to fewer gross production tax credits.

At September 30, 2016, we had the following derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct’16 – Dec’16	Natural gas – swap	45,000 MMBtu/day	$2.596	IF – NYMEX (HH)
Jan’17 – Dec'17	Natural gas – swap	60,000 MMBtu/day	$2.960	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – swap	10,000 MMBtu/day	$3.025	IF – NYMEX (HH)
Jan’17 – Dec'17	Natural gas – basis swap	20,000 MMBtu/day	$(0.215)	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Oct’16 – Dec'16	Natural gas – collar	42,000 MMBtu/day	$2.40 - $2.88	IF – NYMEX (HH)
Jan’17 – Oct'17	Natural gas – collar	20,000 MMBtu/day	$2.88 - $3.10	IF – NYMEX (HH)
Oct’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)

Oct'16 – Dec'16	Crude oil – collar	1,450 Bbl/day	$47.50 - $56.40	WTI – NYMEX
Oct'16 – Dec'16	Crude oil – three-way collar	700 Bbl/day	$46.50 - $35.00 - $57.00	WTI – NYMEX
Oct'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	1,750 Bbl/day	$50.00 - $39.10 - $61.67	WTI – NYMEX

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

After September 30, 2016, we entered into the following derivatives:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'16 – Dec'16	Crude oil – collar	2,000 Bbl/day	$48.00 - $53.15	WTI – NYMEX
Jan'17 – Dec'17	Crude oil – three-way collar	2,000 Bbl/day	$49.60 - $40.00 - $60.38	WTI – NYMEX
Jan'17 – Mar'17	Natural gas – swap	10,000 MMBtu/day	$3.550	IF – NYMEX (HH)

For the nine months ended September 30, 2016, we completed drilling 15 gross wells (7.77 net wells). For all of 2016, we plan to participate in the drilling of approximately 20 gross wells. Excluding acquisitions and ARO liability, our estimated 2016 capital expenditures for this segment are approximately $115.0 million. Our current 2016 production guidance is approximately 16.9 to 17.4 MMBoe, a decrease of 13% to 16% from 2015, although actual results continue to be subject to many factors.

Table of Contents

Contract Drilling

The average number of drilling rigs we operated in the third quarter of 2016 was 16.0 compared to 13.5 and 31.2 in the second quarter of 2016 and the third 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 six months of 2016 because of lower commodity prices and operators reducing their drilling budgets. During the third quarter of 2016, the number of drilling rigs operating started to slowly increase. As of September 30, 2016, 17 of our drilling rigs were operating.

Revenue for the third quarter of 2016 increased 6% over the second quarter of 2016 and decreased 60% from the third quarter of 2015, respectively. The increase over the second quarter of 2016 was due primarily to 2.5 more drilling rigs operating compared to the decrease from the third quarter of 2015 due primarily to 15.2 fewer drilling rigs operating.

Dayrates for the third quarter of 2016 averaged $17,479, a 6% decrease from the second quarter of 2016 and a 7% decrease from the third quarter of 2015. The decreases from both periods were primarily due to downward pressure on dayrates due to lower demand.

Operating costs for the third quarter of 2016 decreased 1% and 46% from the second quarter of 2016 and the third quarter of 2015, respectively. The decreases from the third quarter of 2015 were due primarily to fewer drilling rigs operating.

Mostly 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 impacted demand for drilling rigs. It has effected the drilling rigs used by our customers and our dayrates. We hit a low point during the second quarter of 2016 with only 13 drilling rigs operating. In late June and throughout the third quarter, we began to experience an increase in drilling rig activity with improved, but still volatile commodity prices. We continue to see that improved activity as we start the fourth quarter.

As of September 30, 2016, we had 17 drilling rigs operating. Of those, seven were on term drilling contracts with original terms ranging from six months to three years. One of these term contracts is up for renewal in the fourth quarter of 2016 and six 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. During the third quarter of 2016, no early termination fees were recorded compared to $0.4 million in the second quarter of 2016 and $11.4 million in the third quarter of 2015.

As of September 30, 2016, seven of our eight BOSS drilling rigs were under contract. After the quarter end, we contracted the eighth BOSS drilling rig under a term contract which went to work in October. Additionally, we have secured a term contract to build our ninth BOSS rig, with construction expected to be completed in January 2017. During the third quarter, we completed the previously announced modification of one of our SCR drilling rigs and placed into service under term contract in the Permian Basin. Our estimated 2016 capital expenditures for this segment are approximately $16.0 million.

Mid-Stream

Third quarter 2016 liquids sold per day increased 5% over the second quarter of 2016 and decreased 4% from the third quarter of 2015. The increase over the second quarter of 2016 was due to recovering more liquids at certain processing facilities. The decrease from the third quarter of 2015 was due to less volume to process at our plants. For the third quarter of 2016, gas processed per day decreased 6% from the second quarter of 2016 and decreased 18% from the third quarter of 2015. The decreases were primarily due to declines in existing volumes and fewer new wells connected. For the third quarter of 2016, gas gathered per day decreased 2% from the second quarter of 2016 and increased 20% over the third quarter of 2015. The decrease was primarily due to water related issues causing a temporary shut down at our Snow Shoe gathering system and a temporary shut down of the Segno gathering system because of maintenance on a third-party operated processing plant. The increase from the third quarter of 2015 was primarily from additional wells added to our Pittsburgh Mills gathering system.

NGLs prices in the third quarter of 2016 decreased 10% from the prices received in the second quarter of 2016 and increased 3% over the prices received in the third 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 third quarter of 2016 increased 10% over the second quarter of 2016 and decreased 11% from the third quarter of 2015. Third quarter of 2016 costs were higher than the second quarter of 2016 due to higher gas purchase prices while third quarter of 2016 versus third quarter of 2015 was lower due to lower gas purchase volumes along with lower general and administrative and field direct expenses.

At our Hemphill Texas system, for the third quarter of 2016, our total throughput volume averaged 68.4 MMcf per day and our total production of natural gas liquids was approximately 182,300 gallons per day. At this processing facility we have the capacity to process 135 MMcf per day through three processing skids. During the third quarter, we completed overhauling several company owned compressors.

At our Bellmon processing facility located in the Mississippian play in north central Oklahoma, our total throughput volume averaged approximately 30.5 MMcf per day for the third quarter of 2016. Additionally, during the third quarter, we increased our natural gas liquids volume to approximately 160,300 gallons per day due to operating in ethane recovery mode during the quarter. After installation of additional compression to be able to handle additional third party volumes, we continue to receive gas from third party producers at this facility. During the first nine months of 2016, we connected 15 additional wells to this gathering system. At this processing facility we have two processing skids available that provide total processing capacity of 90 MMcf per day.

At our Segno gathering facility located Southeast Texas, our average transported volume averaged 83.4 MMcf per day for the third quarter of 2016. During the first nine months of the year, we have connected three new wells to this gathering system. With the completion of the GAP pipeline extension project and the addition of dehydration equipment, our total gathering capacity has increased to 120 MMcf per day for this system.

In the Appalachian region, at our Pittsburgh Mills gathering system, we continue to see our average throughput volume increase. During the third quarter of 2016, the total throughput volume increased to approximately 151.1 MMcf per day. During the third quarter of 2016, we connected six new wells to this system bringing the new well connect count to 18 since the beginning of the year. The six new wells were part of the Bello well pad connected in July. The Bello well pad is located on the northern end of our system and delivers gas into NiSource’s Big Pine system.

Also in the Appalachian area at our Snow Shoe gathering system, we have connected three well pads that have a total of six wells during the first nine months of 2016. During the third quarter of 2016, our throughput volume averaged approximately 11.0 MMcf per day. We have completed preliminary construction of the Snow Shoe compressor site, but we will not complete the compressor station until compression services are required.

Our estimated 2016 capital expenditures for this segment are approximately $17.0 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 amount of our cash flow is based primarily on:

- the amount of natural gas, oil, and NGLs we produce;
- the prices we receive for our natural gas, oil, and NGLs production;
- the demand for and the dayrates we receive for our drilling rigs; and
- the fees and margins we obtain from our natural gas gathering and processing contracts.

We currently believe we will 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 2011 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 borrowing base determination under our credit agreement could result in a reduction of the borrowing base 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 our lenders to address those issues, if any, ahead of time.

As part of our efforts 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 first nine months, we sold non-core oil and gas properties for approximately $43.6 million using most of the proceeds to pay

Table of Contents

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.

	Nine Months Ended September 30,		% Change (1)
	2016	2015	
	(In thousands except percentages)		
Net cash provided by operating activities	$ 197,762	$ 381,482	(48)%
Net cash used in investing activities	(107,509)	(474,190)	(77)%
Net cash (used in) provided by financing activities	(90,175)	92,553	(197)%
Net increase (decrease) in cash and cash equivalents	$ 78	$ (155)	

Cash Flows from Operating Activities

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

Net cash provided by operating activities in the first nine months of 2016 decreased by $183.7 million as compared to the first nine months of 2015. The decrease was the result of lower revenues resulting from lower commodity prices, lower drilling rig utilization, and by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital budget to the exploration for and production of oil, NGLs, and natural gas. These expenditures are necessary to off-set the inherent production declines typically experienced in oil and gas wells.

Cash flows used in investing activities decreased by $366.7 million for the first nine months of 2016 compared to the first nine months of 2015. The change was due primarily to a decrease in capital expenditures and an increase in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows (used in) provided by financing activities decreased by $182.7 million for the first nine months of 2016 compared to the first nine months of 2015. The decrease was primarily due to increased borrowings under our credit agreement during 2015 which was paid down during 2016.

At September 30, 2016, we had unrestricted cash totaling $0.9 million and had borrowed $215.0 million of the $475.0 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 September 30, 2016 and 2015 and for the nine months ended September 30, 2016 and 2015:

	September 30,	%

	2016	2015	Change
	(In thousands except percentages)		
Working capital	$(42,342)	$(31,681)	(34)%
Long-term debt less debt issuance costs	$854,583	$908,234	(6)%
Shareholders’ equity	$1,189,576	$1,617,957	(26)%
Net loss	$(137,307)	$(728,024)	(81)%

Table of Contents

The following table summarizes certain operating information:

	Nine Months Ended September 30, 2016	2015	% Change
Oil and Natural Gas:			
Oil production (MBbls)	2,260	2,996	(25)%
NGLs production (MBbls)	3,745	3,954	(5)%
Natural gas production (MMcf)	42,376	49,650	(15)%
Average oil price per barrel received	$38.71	$51.46	(25)%
Average oil price per barrel received excluding derivatives	$36.88	$46.80	(21)%
Average NGLs price per barrel received	$10.16	$9.83	3 %
Average NGLs price per barrel received excluding derivatives	$10.16	$9.83	3 %
Average natural gas price per Mcf received	$1.98	$2.76	(28)%
Average natural gas price per Mcf received excluding derivatives	$1.80	$2.39	(25)%
Contract Drilling:			
Average number of our drilling rigs in use during the period	16.7	37.3	(55)%
Total number of drilling rigs owned at the end of the period	94	94	— %
Average dayrate	$18,147	$19,669	(8)%
Mid-Stream:			
Gas gathered—Mcf/day	417,722	351,619	19 %
Gas processed—Mcf/day	160,411	186,929	(14)%
Gas liquids sold—gallons/day	536,911	582,760	(8)%
Number of natural gas gathering systems	26	25	4 %
Number of processing plants	14	13	8 %

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 $42.3 million and $31.7 million as of September 30, 2016 and 2015, respectively. This is primarily from the change in value of outstanding derivatives and lower accounts receivable due to lower revenues partially offset by the timing of accounts payable associated with our capital expenditures. Our credit agreement is used primarily for working capital and capital expenditures. At September 30, 2016, we had borrowed $215.0 million of the $475.0 million available under our credit agreement. The effect of our derivative contracts decreased working capital by $5.6 million as of September 30, 2016 and increased working capital by $11.5 million as of September 30, 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 nine 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 $449,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of derivatives, during the first nine months of 2016 was $1.98 compared to $2.76 for the first nine months of 2015. Based on our first nine months of 2016 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $242,000 per month ($2.9 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 $397,000 per month ($4.8 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2016, our average oil price per barrel received, including the effect of derivatives, was $38.71 compared with an average oil price, including the effect of derivatives, of $51.46 in the first nine months of 2015 and our first nine months of 2016 average NGLs price per barrel received was $10.16 compared with an average NGLs price per barrel of $9.83 in the first nine 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. In the first three quarters 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, the total non-cash ceiling test write downs recorded for the first nine months of 2016 were $161.6 million pre-tax ($100.6 million, net of tax). The third quarter of 2016 non-cash ceiling test write-down represented $49.4 million ($30.8 million, net of tax) of that total. At September 30, 2016, the 12-month average unescalated prices were $41.68 per barrel of oil, $18.45 per barrel of NGLs, and $2.28 per Mcf of natural gas, then adjusted for price differentials.

It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. In our Form 10-Q for the second quarter of 2016, we disclosed based on those factors, holding July 1, 2016 prices constant for the remaining months of the third quarter, we did not then anticipate a write-down for the third quarter; however, oil and NGL prices decreased in August and September (from July 2016 prices) resulting in us incurring a $49.4 million ($30.8 million, net of tax) non-cash ceiling test write-down for the third quarter of 2016. Subject to these inherent uncertainties, if we hold these same factors constant as they existed on October 1, 2016 and only adjust the 12-month average price to an estimated fourth quarter ending average (holding October 2016 prices constant for the remaining two months of the fourth quarter of 2016), we would not expect to recognize an impairment in the fourth quarter of 2016. Commodity prices remain volatile and they could negatively impact the 12-month average price and the potential for an impairment in the fourth quarter.

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. Under the third amendment to our credit agreement entered into on April 8, 2016, the lenders 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. The October 2016 redetermination did not result in any changes.

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.

In an effort to remain competitive in this low drilling rig utilization market, we reduced the compensation paid to all drilling personnel in April 2016.

Mostly 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 impacted demand for drilling rigs. It has effected the drilling rigs used by our customers and our dayrates. We hit a low point during the second quarter of 2016 with only 13 drilling rigs operating. In late June and throughout the third quarter, we began to experience an increase in drilling rig activity with improved, but still volatile commodity prices. We continue to see that improved activity as we start the fourth quarter. For the first nine months of 2016, our average dayrate was $18,147 per day compared to $19,669 per day for the first nine months of 2015. The average number of our drilling rigs used in the first nine months of 2016 was 16.7 drilling rigs compared with 37.3 drilling rigs in the first nine months of 2015. Based on the average utilization of our drilling rigs during the first nine months of 2016, a $100 per day change in dayrates has a $1,670 per day ($0.6 million annualized) change in our pre-tax operating cash flow.

Table of Contents

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 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 nine months of 2016 and the oil and gas segment did not use any of our rigs in the third quarter. Our oil and gas segment began using one of our contract drilling rigs early in the fourth quarter and plans on adding one more of our drilling rigs late in the fourth quarter. Our oil and natural gas segment planned to incur the majority of its drilling capital expenditures in the latter part of the year allowing to take into account future commodity price movement before those expenditures are incurred. For the first nine months of 2015, we eliminated revenue of $19.1 million from our contract drilling segment and eliminated the associated operating expense of $15.4 million, yielding $3.7 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, 14 processing plants, 26 gathering systems, and approximately 1,459 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. Besides serving third parties, this segment also enhances our ability to gather and market our own natural gas and NGLs and serving as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first nine months of 2016 and 2015, our mid-stream operations purchased $28.5 million and $47.2 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $7.4 million and $5.7 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 417,722 Mcf per day in the first nine months of 2016 compared to 351,619 Mcf per day in the first nine months of 2015. It processed an average of 160,411 Mcf per day in the first nine months of 2016 compared to 186,929 Mcf per day in the first nine months of 2015. The amount of NGLs sold was 536,911 gallons per day in the first nine months of 2016 compared to 582,760 gallons per day in the first nine months of 2015. Gas gathering volumes per day in the first nine months of 2016 increased 19% compared to the first nine months of 2015 primarily from additional wells added to our Pittsburgh Mills gathering system. Processed volumes for the first nine months of 2016 decreased 14% from the first nine months of 2015 due to declines in existing wells in our systems where we process gas combined with few replacement wells due to decreased drilling activity by operators in those areas. NGLs sold decreased 8% 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 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 $875.0 million. Our elected commitment amount is $475.0 million. Our borrowing base is $475.0 million. We are charged a commitment fee of 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 $1.0 million in origination, agency, syndication, and other related fees. We are amortizing these fees 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.

34

Table of Contents

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. The October 2016 redetermination did not result in any changes. 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 2.00% to 3.00% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the 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 September 30, 2016 and October 21, 2016, borrowings were $215.0 million and $205.0 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 acquisition of contract drilling equipment, 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.

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

- 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.

As of September 30, 2016, we were in compliance with the covenants in the credit agreement.

Table of Contents

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

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms of and providing for the issuance of the Notes. The Guarantors are most of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the 2011 Indenture. 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.

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 September 30, 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 15 gross wells (7.77 net wells) in the first nine months of 2016 compared to 42 gross wells (28.29 net wells) in the first nine months of 2015. Capital expenditures for oil and gas properties on the full cost method for the first nine months of 2016 by this segment, excluding a $29.4 million reduction in the ARO liability, totaled $91.9 million. Capital expenditures for the first nine months of 2015, excluding a $8.6 million reduction in the ARO liability, totaled $220.0 million.

Currently we plan to participate in drilling approximately 20 gross wells in 2016 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $115.0 million. Whether we can drill the full number of wells planned depends on several factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. During the second quarter of 2015, we recorded a write-down of approximately $8.3 million pre-tax on drilling equipment that was being held for sale. During the third quarter of 2015, we sold 30 drilling rigs and drilling equipment at auction. The proceeds from that sale, less costs to sell, was less than the $11.0 million net book value resulting in a loss of $7.3 million pre-tax.

Three BOSS drilling rigs were placed into service in 2014 along with an additional five placed into service in 2015 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. During the fourth quarter of 2016, we were awarded a term contract to build our ninth BOSS rig, with construction expected to be completed in January 2017.

Our estimated 2016 capital expenditures for this segment are approximately $16.0 million. At September 30, 2016, we had commitments to purchase approximately $4.8 million for drilling equipment over the next two years. We have spent $7.2

Table of Contents

million for capital expenditures during the first nine months of 2016, compared to $81.6 million for capital expenditures, including $57.8 million for the BOSS drilling rigs, during the first nine months of 2015.

Mid-Stream Acquisitions and Capital Expenditures. At our Hemphill Texas system, for the third quarter of 2016, our total throughput volume averaged 68.4 MMcf per day and our total production of natural gas liquids was approximately 182,300 gallons per day. At this processing facility we have the capacity to process 135 MMcf per day through three processing skids. During the third quarter, we completed overhauling several company owned compressors.

At our Bellmon processing facility located in the Mississippian play in north central Oklahoma, our total throughput volume averaged approximately 30.5 MMcf per day for the third quarter of 2016. Additionally, during the third quarter, we increased our natural gas liquids volume to approximately 160,300 gallons per day due to operating in ethane recovery mode during the quarter. After installation of additional compression to be able to handle additional third party volumes, we continue to receive gas from third party producers at this facility. During the first nine months of 2016, we connected 15 additional wells to this gathering system. At this processing facility we have two processing skids available that provide total processing capacity of 90 MMcf per day.

At our Segno gathering facility located Southeast Texas, our average transported volume averaged 83.4 MMcf per day for the third quarter of 2016. During the first nine months of the year, we have connected three new wells to this gathering system. With the completion of the GAP pipeline extension project and the addition of dehydration equipment, our total gathering capacity has increased to 120 MMcf per day for this system.

In the Appalachian region, at our Pittsburgh Mills gathering system, we continue to see our average throughput volume increase. During the third quarter of 2016, the total throughput volume increased to approximately 151.1 MMcf per day. During the third quarter of 2016, we connected six new wells to this system bringing the new well connect count to 18 since the beginning of the year. The six new wells were part of the Bello well pad connected in July. The Bello well pad is located on the northern end of our system and delivers gas into NiSource’s Big Pine system.

Also in the Appalachian area at our Snow Shoe gathering system, we have connected three well pads that have a total of six wells during the first nine months of 2016. During the third quarter of 2016, our throughput volume averaged approximately 11.0 MMcf per day. We have completed preliminary construction of the Snow Shoe compressor site, but we will not complete the compressor station until compression services are required.

During the first nine months of 2016, our mid-stream segment incurred $11.1 million in capital expenditures as compared to $43.9 million in the first nine months of 2015. For 2016, our estimated capital expenditures are approximately $17.0 million.

Table of Contents

Contractual Commitments

At September 30, 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]	$1,083,162	$48,486	$96,972	$937,704	$ —
Operating leases [2]	3,694	2,506	1,044	144	—
Capital lease interest and maintenance[3]	10,165	2,512	4,570	3,083	—
Drill pipe, drilling components, and equipment purchases [4]	4,763	3,791	972	—	—
Enterprise Resource Planning software obligations [5]	1,436	950	486	—	—
Total contractual obligations	$1,103,220	$58,245	$104,044	$940,931	$ —

____

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our September 30, 2016 interest rates of 6.625% for the Notes and 2.5% for the credit agreement. Our credit agreement has a maturity date of April 10, 2020.

(2) We lease office space or yards in Woodward and Oklahoma City, 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 $8.1 million and $2.1 million, respectively.

(4) We have committed to pay $4.8 million for drilling rig components, drill pipe, and related equipment over the next two years.

(5) We have committed to pay $0.9 million for Enterprise Resource Planning software and $0.5 million for maintenance for one year following implementation.

Table of Contents

At September 30, 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)	$4,470	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$5,289	$ 2,131	Unknown	Unknown	Unknown
Asset retirement liability (3)	$71,021	$ 3,498	$ 43,849	$ 6,080	$ 17,594
Gas balancing liability (4)	$3,806	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability(6)	$15,185	$ 7,056	$ 2,018	$ 1,043	$ 5,068
Capital leases obligations (7)	$19,818	$ 3,657	$ 7,767	$ 8,394	$ —
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.

(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 $118,000 during the first nine months of 2015 but did not have any for the first nine months 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.

Table of Contents

Commodity Derivatives. Our commodity derivatives are intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. At September 30, 2016, based on our third quarter 2016 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Q4 2016	Q1	Q2	Q3	Q4	2018
Daily oil production	37%	23%	23%	23%	23%	—%
Daily natural gas production	69%	65%	65%	65%	56%	7 %

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

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our September 30, 2016 evaluation, we believe the risk of non-performance by our counterparties is not material. At September 30, 2016, the fair values of the net liabilities we had with each of the counterparties to our commodity derivative transactions are as follows:

	September 30, 2016 (In millions)
Bank of Montreal	$ (2.5)
Canadian Imperial Bank of Commerce	(1.2)
Scotiabank	(1.1)
Bank of America Merrill Lynch	(0.8)
Total liabilities	$ (5.6)

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At September 30, 2016, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.2 million and current and non-current derivative liabilities of $5.5 million and $0.3 million, respectively. At September 30, 2015, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $11.5 million and $0.4 million, respectively.

For our economic hedges any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Unaudited Condensed Consolidated Statements of Operations. These gains (losses) at September 30 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Gain (loss) on derivatives:				
Gain (loss) on derivatives, included are amounts settled during the period of ($457), $11,074, $11,735, and $32,156, respectively	$6,969	$8,250	$(4,774)	$12,917
	$6,969	$8,250	$(4,774)	$12,917

40

Table of Contents

Stock and Incentive Compensation

During the first nine months of 2016, we granted awards covering 728,951 shares of restricted stock. These awards had an estimated fair value as of their grant date of $4.2 million. Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2016, we recognized $1.1 million in compensation expense and capitalized $0.2 million for these awards. During the first nine months of 2016, we recognized compensation expense of $7.2 million for all of our restricted stock, stock options, and SAR grants and capitalized $1.6 million of compensation cost for oil and natural gas properties.

During the first nine months of 2015 we granted awards covering 750,290 shares of restricted stock. These awards had an estimated fair value as of their grant date of $24.5 million. Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2015, we recognized $5.5 million in compensation expense and capitalized $1.3 million for these awards. During the first nine months of 2015, we recognized compensation expense of $11.2 million for all of our restricted stock, stock options, and SAR grants and capitalized $2.6 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 the first nine months of 2016 and 2015, the total we received for all of these fees was $0.2 million and $0.3 million, respectively. 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

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. The FASB issued ASU 2016-15, to address diversity in how certain transactions are presented and classified in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 31, 2017, and early adoption is permitted. We do not believe this ASU will have a material impact on our financial statements.

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. We do not believe the amendments will have a material impact on our financial statements.

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

Table of Contents

beginning after December 15, 2018, and interim periods within those annual periods. Early adoption of the amendments in permitted. We are in the process of evaluating the impact these amendments 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. We do not believe the amendments will have a material impact on our financial statements.

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 during the first quarter of 2016. 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.

Presentation of Financial Statements-Going Concern: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The FASB has issued ASU 2014-15. This is intended to define management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern and to provide related footnote disclosures. For each reporting period, management will be required to evaluate whether there are conditions or events that raise substantial doubt about a company's ability to continue as a going concern within one year from the date financial statements are issued. The amendments are effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. Early application is permitted for annual or interim reporting periods for which the financial statements have not previously been issued. We will begin performing the assessments and making any disclosures, if applicable, beginning at the end of fiscal year 2016.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This guidance 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 May 2016, the FASB issued ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients," which provides clarifying guidance in certain areas and adds some practical expedients. Also in May 2016, the FASB issued ASU 2016-11, "Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting." This ASU rescinds SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities— Oil and Gas, effective upon the adoption of Topic 606, Revenue from Contracts with Customers.

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. The FASB has issued 2015-14, which defers the effective date to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. We are in the process of evaluating the impact this guidance will have on our financial statements.

Table of Contents

Results of Operations

Quarter Ended September 30, 2016 versus Quarter Ended September 30, 2015

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

	Quarter Ended September 30, 2016	2015	Percent Change
	(In thousands unless otherwise specified)		
Total revenue	$153,408	$212,393	(28)%
Net loss	$(24,022)	$(205,281)	(88)%
Oil and Natural Gas:			
Revenue	$78,854	$96,619	(18)%
Operating costs excluding depreciation, depletion, amortization, and impairment	$26,014	$38,688	(33)%
Depreciation, depletion, and amortization	$27,135	$57,159	(53)%
Impairment of oil and natural gas properties	$49,443	$329,924	(85)%
Average oil price received (Bbl)	$42.79	$50.87	(16)%
Average NGLs price received (Bbl)	$12.68	$8.74	45 %
Average natural gas price received (Mcf)	$2.29	$2.66	(14)%
Oil production (Bbl)	701,000	950,000	(26)%
NGLs production (Bbl)	1,260,000	1,339,000	(6)%
Natural gas production (Mcf)	13,399,000	16,586,000	(19)%
Depreciation, depletion, and amortization rate (Boe)	$6.06	$10.98	(45)%
Contract Drilling:			
Revenue	$25,819	$65,022	(60)%
Operating costs excluding depreciation	$19,137	$35,486	(46)%
Depreciation	$11,318	$14,255	(21)%
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	16.0	31.2	(49)%
Average dayrate on daywork contracts	$17,479	$18,800	(7)%
Mid-Stream:			
Revenue	$48,735	$50,752	(4)%
Operating costs excluding depreciation and amortization	$35,738	$40,314	(11)%
Depreciation and amortization	$11,436	$10,976	4 %
Gas gathered—Mcf/day	429,693	357,427	20 %
Gas processed—Mcf/day	152,651	185,625	(18)%
Gas liquids sold—gallons/day	558,843	579,556	(4)%
Corporate and other:			
General and administrative expense	$8,932	$7,643	17 %
Gain (loss) on disposition of assets	$154	$(7,230)	102.1 %
Other income (expense):			
Interest expense, net	$(10,002)	$(8,286)	21 %
Gain on derivatives	$6,969	$8,250	(16)%

Other	$3	$16	(81)%
Income tax benefit	$(14,599)	$(124,021)	(88)%
Average long-term debt outstanding	$866,249	$920,020	(6)%
Average interest rate	5.7 %	5.3 %	8 %

43

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues decreased $17.8 million or 18% in the third quarter of 2016 as compared to the third quarter of 2015 primarily due to lower oil and natural gas prices and from reduced production volumes. In the third quarter of 2016, as compared to the third quarter of 2015, oil production decreased 26%, natural gas production decreased 19%, and NGLs production decreased 6%. Average oil prices decreased 16% to $42.79 per barrel, average natural gas prices decreased 14% to $2.29 per Mcf, and NGLs prices increased 45% to $12.68 per barrel.

Oil and natural gas operating costs decreased $12.7 million or 33% between the comparative third quarters of 2016 and 2015 due to lower LOE, saltwater disposal expense, and general and administrative expenses partially offset by higher gross production taxes due to fewer gross production tax credits.

Depreciation, depletion, and amortization (“DD&A”) decreased $30.0 million or 53% due primarily to a 45% decrease in our DD&A rate and a 17% decrease in equivalent production. The decrease in our DD&A rate in the third quarter of 2016 compared to the third quarter of 2015 resulted primarily from the effect of the ceiling test write-downs throughout 2015 and 2016. 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 third quarter of 2015, we recorded a non-cash ceiling test write-down of $329.9 million pre-tax ($205.4 million, net of tax). During the third quarter of 2016, we recorded a non-cash ceiling test write-down of $49.4 million pre-tax ($30.8 million, net of tax).

Contract Drilling

Drilling revenues decreased $39.2 million or 60% in the third quarter of 2016 versus the third quarter of 2015. The decrease was due primarily to a 49% decrease in the average number of drilling rigs in use as well as a 7% decrease in the average dayrate. Average drilling rig utilization decreased from 31.2 drilling rigs in the third quarter of 2015 to 16.0 drilling rigs in the third quarter of 2016. There was no revenue on contracts that terminated early in the third quarter of 2016 compared to $11.4 million in the third quarter of 2015.

Drilling operating costs decreased $16.3 million or 46% between the comparative third quarters of 2016 and 2015. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased $2.9 million or 21% also due primarily to fewer drilling rigs operating.

Mid-Stream

Our mid-stream revenues decreased $2.0 million or 4% in the third quarter of 2016 as compared to the third quarter of 2015 due primarily from the average price for natural gas sold decreasing 3% and from gas sales and liquids volumes decreasing 19% and 4%, respectively, offset partially by an increase in transportation volumes and prices of 63% and 11%, respectively. Gas processing volumes per day decreased 18% between the comparative quarters primarily due to declines in existing volumes. Gas gathering volumes per day increased 20% between the comparative quarters primarily due to additional wells added to our Pittsburgh Mills gathering system.

Operating costs decreased $4.6 million or 11% in the third quarter of 2016 compared to the third quarter of 2015 primarily due to an 18% decrease in purchase volumes along with an 8% decrease in field direct expenses slightly offset by increased gas purchase prices of 5%. Depreciation and amortization increased $0.5 million, or 4%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

Corporate general and administrative expenses increased $1.3 million or 17% in the third quarter of 2016 compared to the third quarter of 2015 primarily from the third quarter of 2015 including a $1.8 million reduction in the stock-based compensation accrual due to an evaluation of the performance based shares component of previous grants offset by the third quarter of 2016 including lower employee costs due to 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 third quarter of 2016 primarily due to the sale of vehicles compared to a loss of $7.2 million for the disposition of assets in the third quarter of 2015 primarily due to the sale of 30 drilling rigs and other drilling equipment at auction. The proceeds from the sale of those assets, less costs to sell, was less than the $11.0 million net book value resulting in a loss of $7.3 million pre-tax.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $1.7 million between the comparative third quarters of 2016 and 2015 due primarily to decreased capitalized interest in the third quarter of 2016 due to fewer capital expenditures and a decrease in undeveloped leasehold not being amortized. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the third quarter of 2016 was $3.6 million compared to $5.2 million in the third quarter of 2015, and was netted against our gross interest of $13.6 million and $13.5 million for the third quarters of 2016 and 2015, respectively. Our average interest rate increased from 5.3% in the third quarter of 2015 to 5.7% in the third quarter of 2016 and our average debt outstanding was $53.8 million lower in the third quarter of 2016 as compared to the third quarter of 2015 primarily due to the decrease in outstanding borrowings under our credit agreement over the comparative periods.

Gain on derivatives decreased $1.3 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Benefit

Income tax benefit decreased $109.4 million between the comparative third quarters of 2016 and 2015 primarily due to decreased pre-tax loss primarily from a lower non-cash ceiling test write-down in the third quarter of 2016 versus the third quarter of 2015. Our effective tax rate was 37.8% for the third quarter of 2016 compared to 37.7% for the third quarter of 2015. There was no current income tax benefit in the third quarter of 2016 compared to $2.6 million for the third quarter of 2015. We did not pay any income taxes in the third quarter of 2016.

Table of Contents

Nine Months Ended September 30, 2016 versus Nine Months Ended September 30, 2015
Provided below is a comparison of selected operating and financial data:

	Nine Months Ended September 30,		Percent Change
	2016	2015	
	(In thousands unless otherwise specified)		
Total revenue	$427,897	$681,939	(37)%
Net loss	$(137,307)	$(728,024)	(81)%
Oil and Natural Gas:			
Revenue	$206,318	$309,944	(33)%
Operating costs excluding depreciation, depletion, amortization, and impairment	$92,691	$129,871	(29)%
Depreciation, depletion, and amortization	$89,378	$202,378	(56)%
Impairment of oil and natural gas properties	$161,563	$1,141,053	(86)%
Average oil price received (Bbl)	$38.71	$51.46	(25)%
Average NGLs price received (Bbl)	$10.16	$9.83	3 %
Average natural gas price received (Mcf)	$1.98	$2.76	(28)%
Oil production (Bbl)	2,260,000	2,996,000	(25)%
NGLs production (Bbl)	3,745,000	3,954,000	(5)%
Natural gas production (Mcf)	42,376,000	49,650,000	(15)%
Depreciation, depletion, and amortization rate (Boe)	$6.48	$12.96	(50)%
Contract Drilling:			
Revenue	$88,786	$215,114	(59)%
Operating costs excluding depreciation	$66,489	$123,717	(46)%
Depreciation	$34,431	$42,533	(19)%
Impairment of contract drilling equipment	$—	$8,314	(100)%
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	16.7	37.3	(55)%
Average dayrate on daywork contracts	$18,147	$19,669	(8)%
Mid-Stream:			
Revenue	$132,793	$156,881	(15)%
Operating costs excluding depreciation and amortization	$99,185	$125,081	(21)%
Depreciation and amortization	$34,410	$32,518	6 %
Gas gathered—Mcf/day	417,722	351,619	19 %
Gas processed—Mcf/day	160,411	186,929	(14)%
Gas liquids sold—gallons/day	536,911	582,760	(8)%
Corporate and other:			
General and administrative expense	$26,029	$26,637	(2)%
Gain (loss) on disposition of assets	$823	$(6,270)	113 %
Other income (expense):			
Interest expense, net	$(30,225)	$(23,482)	29 %
Gain (loss) on derivatives	$(4,774)	$12,917	(137)%

Other	$(11)	$38	(129)%
Income tax benefit	$(73,159)	$(438,936)	(83)%
Average long-term debt outstanding	$882,330	$891,173	(1)%
Average interest rate	5.6 %	5.5 %	2 %

46

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues decreased $103.6 million or 33% in the first nine months 2016 as compared to the first nine months of 2015 primarily due to lower oil and natural gas prices and from reduced production volumes. In the first nine months of 2016, as compared to the first nine months of 2015, oil production decreased 25%, natural gas production decreased 15%, and NGLs production decreased 5%. Average oil prices decreased 25% to $38.71 per barrel, average natural gas prices decreased 28% to $1.98 per Mcf, and NGLs prices increased 3% to $10.16 per barrel.

Oil and natural gas operating costs decreased $37.2 million or 29% between the comparative first nine months 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.

DD&A decreased $113.0 million or 56% due primarily to a 50% decrease in our DD&A rate and a 14% decrease in equivalent production. The decrease in our DD&A rate in the first nine months of 2016 compared to the first nine months of 2015 resulted primarily from the effect of the ceiling test write-downs throughout 2015 and 2016. 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 nine months of 2015, we recorded non-cash ceiling test write-downs of $1.1 billion pre-tax ($710.4 million, net of tax). During the first nine months of 2016, we recorded non-cash ceiling test write-downs of $161.6 million pre-tax ($100.6 million, net of tax).

Contract Drilling

Drilling revenues decreased $126.3 million or 59% in the first nine months of 2016 versus the first nine months of 2015. The decrease was due primarily to a 55% decrease in the average number of drilling rigs in use as well as an 8% decrease in the average dayrate. Average drilling rig utilization decreased from 37.3 drilling rigs in the first nine months of 2015 to 16.7 drilling rigs in the first nine months of 2016. Revenue on contracts that terminated early were $3.1 million in the first nine months of 2016 compared to $25.7 million in the first nine months of 2015.

Drilling operating costs decreased $57.2 million or 46% between the comparative first nine months of 2016 and 2015. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased $8.1 million or 19% also due primarily to fewer drilling rigs operating. During the first nine months of 2015, we recorded a write-down of approximately $8.3 million pre-tax on drilling equipment that was being held for sale.

Mid-Stream

Our mid-stream revenues decreased $24.1 million or 15% in the first nine months of 2016 as compared to the first nine months of 2015 due primarily from the average price for natural gas, liquids, and condensate sold decreasing 21%, 10%, and 23%, respectively and from gas sales, liquids, and condensate volumes decreasing 15%, 8%, and 2%, respectively, offset partially by an increase in transportation volumes and prices of 59% and 8%, respectively. Gas processing volumes per day decreased 14% between the comparative periods primarily due to declines in existing volumes. Gas gathering volumes per day increased 19% between the comparative periods primarily due to additional wells added to our Pittsburgh Mills gathering system.

Operating costs decreased $25.9 million or 21% in the first nine months of 2016 compared to the first nine months of 2015 primarily due to an 18% decrease in prices paid for natural gas purchased and a 14% decrease in purchase volumes along with an 7% decrease in field direct expenses and a 7% decrease in general and administrative expense.

Depreciation and amortization increased $1.9 million, or 6%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

Corporate general and administrative expenses decreased $0.6 million or 2% in the first nine months of 2016 compared to the first nine months of 2015 primarily due to lower employee costs and a reduction to our workforce during the first quarter of 2016.

Table of Contents

Gain on Disposition of Assets

There was an $0.8 million gain on disposition of assets in the first nine months of 2016 primarily due to the sale of various rig components (including three top drives and power units), vehicles, and a drilling yard, compared to a loss of $6.3 million for the disposition of assets in the first nine months of 2015 primarily due to the sale during the third quarter of 30 drilling rigs and other drilling equipment in an auction offset by the gains on the sale of one gathering system, various rig components, vehicles and a drilling rig in the first nine months of 2015.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $6.7 million between the comparative first nine months of 2016 and 2015 due primarily to decreased capitalized interest in the first nine months of 2016 due to fewer capital expenditures and a decrease in undeveloped leasehold not being amortized. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the first nine months of 2016 was $11.2 million compared to $16.6 million in the first nine months of 2015, and was netted against our gross interest of $41.4 million and $40.1 million for the first nine months of 2016 and 2015, respectively. Our average interest rate increased from 5.5% to 5.6% and our average debt outstanding was $8.8 million lower in the first nine months of 2016 as compared to the first nine months of 2015 primarily due to the decrease in outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives decreased $17.7 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 $365.8 million between the comparative first nine months of 2016 and 2015 primarily due to decreased pre-tax loss primarily from lower non-cash ceiling test write-downs in the first nine months of 2016 versus the first nine months of 2015. Our effective tax rate was 34.8% for the first nine months of 2016 compared to 37.6% for the first nine months of 2015. This decrease is primarily due to increased deferred tax expense in the first nine months of 2016 related to our restricted stock vestings in the first nine months of 2016 after the exhaustion of our remaining accumulated excess tax benefits. There was no current income tax benefit in the first nine months of 2016 compared to $1.7 million for the first nine months of 2015. We did not pay any income taxes in the first nine months 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,” a 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;
- 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;

Table of Contents

- 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 initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets;
- our financial condition and liquidity;
- the number of wells our oil and natural gas segment plans to drill or rework during the year; 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;
- changes in the current geopolitical situation;
- risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
- risks associated with future weather conditions;
- decreases or increases in commodity prices;
- our ability to successfully implement our pending technology conversion process relating to our financial and operational information systems; 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.

Table of Contents

Item 3. Quantitative and Qualitative Disclosure About Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, these prices have fluctuated and we expect this to continue. The prices for oil, NGLs, and natural gas also affect the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first nine months 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 $449,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $242,000 per month ($2.9 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 $397,000 per month ($4.8 million annualized) change in our pre-tax operating cash flow.

We use derivative transactions to manage the risk associated with price volatility. Our decisions regarding the amount and prices at which we choose to enter into a contract for certain of our products is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At September 30, 2016, we had the following derivatives outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct’16 – Dec’16	Natural gas – swap	45,000 MMBtu/day	$2.596	IF – NYMEX (HH)
Jan’17 – Dec'17	Natural gas – swap	60,000 MMBtu/day	$2.960	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – swap	10,000 MMBtu/day	$3.025	IF – NYMEX (HH)
Jan’17 – Dec'17	Natural gas – basis swap	20,000 MMBtu/day	$(0.215)	IF – NYMEX (HH)
Jan’18 – Dec'18	Natural gas – basis swap	10,000 MMBtu/day	$(0.208)	IF – NYMEX (HH)
Oct’16 – Dec'16	Natural gas – collar	42,000 MMBtu/day	$2.40 - $2.88	IF – NYMEX (HH)
Jan’17 – Oct'17	Natural gas – collar	20,000 MMBtu/day	$2.88 - $3.10	IF – NYMEX (HH)
Oct’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)
Oct’16 – Dec'16	Crude oil – collar	1,450 Bbl/day	\$47.50 - \$56.40	WTI – NYMEX
Oct’16 – Dec'16	Crude oil – three-way collar	700 Bbl/day	\$46.50 - \$35.00 - \$57.00	WTI – NYMEX
Oct'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	1,750 Bbl/day	\$50.00 - \$39.10 - \$61.67	WTI – NYMEX

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

After September 30, 2016, we entered into the following derivatives:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct’16 – Dec'16	Crude oil – collar	2,000 Bbl/day	\$48.00 - \$53.15	WTI – NYMEX
Jan’17 – Dec'17	Crude oil – three-way collar	2,000 Bbl/day	\$49.60 - \$40.00 - \$60.38	WTI – NYMEX
Jan’17 – Mar'17	Natural gas – swap	10,000 MMBtu/day	\$3.550	IF – NYMEX (HH)

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 nine months of 2016, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately \$2.3 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).

Table of Contents

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 September 30, 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 September 30, 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.

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.

Table of Contents

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

The following table provides information relating to our repurchase of common stock for the three months ended September 30, 2016:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2016 to July 31, 2016	—	$ ——		—
August 1, 2016 to August 31, 2016	—	—	—	—
September 1, 2016 to September 30, 2016	—	—	—	—
Total	—	$ ——		—

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Table of Contents

Item 6. Exhibits

Exhibits:

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.

Table of Contents

SIGNATURES

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

		Unit Corporation
Date:	November 3, 2016	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date:	November 3, 2016	By: /s/ David T. Merrill DAVID T. MERRILL Senior Vice President, Chief Financial Officer, and Treasurer