UNIT CORP
Form 10-Q
November 03, 2015
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, 2015
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
[Commission File Number 1-9260]
UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	73-1283193
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)
7130 South Lewis, Suite 1000, Tulsa, Oklahoma	74136
(Address of principal executive offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [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 23, 2015, 50,414,408 shares of the issuer's common stock were outstanding.

Table of Contents

TABLE OF CONTENTS

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, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, natural gas liquids (NGLs), and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory actions affecting our costs and increasing operating restrictions or delays and other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our estimates of the amounts of any ceiling test write-downs 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, and other factors we believe are appropriate in the circumstances. Whether actual results and developments will conform to our expectations and predictions is subject to several risks and uncertainties, any one or combination of which could cause our actual results to differ materially from our expectations and predictions, including:

- the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in demand for and the price for commodities; and
- other factors, most of which are beyond our control.

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

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2015	December 31, 2014
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 894	$ 1,049
Accounts receivable, net of allowance for doubtful accounts of $4,758 and $5,039 at September 30, 2015 and at December 31, 2014, respectively	101,155	189,812
Materials and supplies	7,704	5,590
Current derivative asset (Note 10)	11,461	31,139
Current income taxes receivable	4,494	—
Current deferred tax asset	8,340	11,527
Assets held for sale (Note 3)	5,321	—
Prepaid expenses and other	11,301	13,374
Total current assets	150,670	252,491
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	5,229,832	4,990,753
Unproved properties not being amortized	454,156	485,568
Drilling equipment	1,563,433	1,620,692
Gas gathering and processing equipment	669,512	628,689
Saltwater disposal systems	60,271	56,702
Transportation equipment	40,138	40,693
Other	82,496	57,706
	8,099,838	7,880,803
Less accumulated depreciation, depletion, amortization, and impairment	5,053,204	3,747,412
Net property and equipment	3,046,634	4,133,391
Debt issuance cost	9,064	10,255
Goodwill	62,808	62,808
Non-current derivative asset (Note 10)	439	—
Other assets	14,903	14,783
Total assets	$ 3,284,518	$ 4,473,728

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, 2015	December 31, 2014
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 97,503	$ 218,500
Accrued liabilities (Note 5)	68,042	70,171
Income taxes payable	—	481
Current portion of other long-term liabilities (Note 6)	16,806	15,019
Total current liabilities	182,351	304,171
Long-term debt (Note 6)	908,234	812,163
Other long-term liabilities (Note 6)	136,981	148,785
Deferred income taxes	438,995	876,215
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, 50,414,408 and 49,593,812 shares issued as of September 30, 2015 and December 31, 2014, respectively	9,831	9,732
Capital in excess of par value	481,611	468,123
Retained earnings	1,126,515	1,854,539
Total shareholders' equity	1,617,957	2,332,394
Total liabilities and shareholders' equity	$ 3,284,518	$ 4,473,728

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,	
	2015	2014	2015	2014
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$96,619	$188,471	$309,944	$575,176
Contract drilling	65,022	120,652	215,114	341,530
Gas gathering and processing	50,752	91,851	156,881	277,687
Total revenues	212,393	400,974	681,939	1,194,393
Expenses:				
Oil and natural gas:				
Operating costs	38,688	48,841	129,871	133,979
Depreciation, depletion, and amortization	57,159	70,033	202,378	200,958
Impairment of oil and natural gas properties (Note 2)	329,924	—	1,141,053	—
Contract drilling:				
Operating costs	35,486	66,727	123,717	197,025
Depreciation	14,255	22,560	42,533	61,194
Impairment of contract drilling equipment (Note 3)	—	—	8,314	—
Gas gathering and processing:				
Operating costs	40,314	78,558	125,081	238,166
Depreciation and amortization	10,976	10,272	32,518	29,972
General and administrative	7,643	10,172	26,637	30,409
(Gain) loss on disposition of assets	7,230	529	6,270	(9,092)
Total operating expenses	541,675	307,692	1,838,372	882,611
Income (loss) from operations	(329,282)	93,282	(1,156,433)	311,782
Other income (expense):				
Interest, net	(8,286)	(4,280)	(23,482)	(12,201)
Gain (loss) on derivatives not designated as hedges (Note 10)	8,250	19,841	12,917	(9,234)
Other	16	(68)	38	3
Total other expense	(20)	15,493	(10,527)	(21,432)
Income (loss) before income taxes	(329,302)	108,775	(1,166,960)	290,350
Income tax expense (benefit):				
Current	(2,584)	5,451	(1,716)	23,721
Deferred	(121,437)	35,802	(437,220)	87,802
Total income taxes	(124,021)	41,253	(438,936)	111,523
Net income (loss)	$(205,281)	$67,522	$(728,024)	$178,827
Net income (loss) per common share:				
Basic	$(4.18)	$1.39	$(14.83)	$3.68
Diluted	$(4.18)	$1.37	$(14.83)	$3.65

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,	
	2015	2014
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	$(728,024)	$178,827
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	279,739	294,412
Impairments (Notes 2 and 3)	1,149,367	—
(Gain) loss on derivatives (Note 10)	(12,917)	9,234
Cash receipts (payments) on derivatives settled (Note 10)	32,156	(18,984)
Deferred tax expense (benefit)	(437,220)	87,802
(Gain) loss on disposition of assets	6,270	(9,092)
Employee stock compensation plans	12,514	17,780
Other, net	1,834	5,156
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	84,098	(47,704)
Accounts payable	(4,432)	1,708
Material and supplies	(2,114)	2,222
Accrued liabilities	(363)	28,596
Other, net	574	(430)
Net cash provided by operating activities	381,482	549,527
INVESTING ACTIVITIES:		
Capital expenditures	(484,028)	(686,405)
Proceeds from disposition of assets	9,838	49,341
Other	—	303
Net cash used in investing activities	(474,190)	(636,761)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	484,600	395,700
Payments under credit agreement	(388,900)	(364,900)
Payments on capitalized leases	(2,648)	(1,505)
Proceeds from exercise of stock options	4	926
Book overdrafts	(503)	39,315
Net cash provided by financing activities	92,553	69,536
Net decrease in cash and cash equivalents	(155)	(17,698)
Cash and cash equivalents, beginning of period	1,049	18,593
Cash and cash equivalents, end of period	$894	$895
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	12,691	(1,340)
Income taxes	3,277	16,000
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	116,062	(42,651)
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	8,558	40,516
Non-cash additions to property, plant, and equipment acquired under capital leases	—	(28,202)

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

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The 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 24, 2015, for the year ended December 31, 2014.

In our management's opinion, 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, 2015 and December 31, 2014;
- Statements of Operations for the three and nine months ended September 30, 2015 and 2014; and
- Statements of Cash Flows for the nine months ended September 30, 2015 and 2014.

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, 2015 and 2014 are not necessarily indicative of the results to be realized for the full year of 2015, or that we realized for the full year of 2014.

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

Regarding the unaudited financial information for the three and nine month periods ended September 30, 2015 and 2014, our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures under professional standards in reviewing that information. Its separate report dated November 3, 2015, which is included in this report, states it did not audit nor did it express an opinion on that unaudited financial information. The reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (Act) for its report on the unaudited financial information because that report is not a "report" or a "part" of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 – OIL AND NATURAL GAS PROPERTIES

Full cost accounting rules require us to review the carrying value of our oil and natural gas properties at the end of each quarter. Under those rules, the maximum amount allowed as the carrying value is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (using the unescalated 12-month average price of our oil, NGLs, and natural gas), plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net book value of the oil, NGLs, and natural gas properties being amortized exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs. We are required to take the charge even if prices are depressed for only a short while. Once incurred, a write-down of oil and natural gas properties is not reversible.

During the first and second quarter quarter of 2015, the 12-month average commodity prices decreased significantly, resulting in non-cash ceiling test write-downs of $400.6 million pre-tax ($249.4 million, net of tax) and $410.5 million pre-tax ($255.6 million, net of tax), respectively.

Table of Contents

During the third quarter of 2015, the 12-month average commodity prices decreased further, resulting in a non-cash ceiling test write-down of $329.9 million pre-tax ($205.4 million, net of tax).

NOTE 3 – DIVESTITURES

Oil and Natural Gas

We sold non-core oil and natural gas assets, net of related expenses, for $0.2 million during the first nine months of 2015, compared to $18.5 million during the first nine months of 2014. Proceeds from those sales reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment and based on estimated market value from third party assessments (Level 3 fair value measurement), we recorded a write-down of approximately $74.3 million pre-tax. During the first quarter of 2015, we sold one of these drilling rigs to an unaffiliated third party. The proceeds of this sale, less costs to sell, exceeded the $0.3 million net book value of the drilling rig resulting in a gain of $7,900. During the second quarter, we recorded an additional write-down on the remaining drilling rigs and other equipment of approximately $8.3 million pre-tax based on the estimated market value from similar auctions. During the third quarter we sold the remaining 30 drilling rigs and most of the equipment in an 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. The equipment that was not sold at the auction will be sold within the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.3 million.

During the first quarter of 2014, we sold four idle 3,000 horsepower drilling rigs to an unaffiliated third-party. The proceeds of this sale, less sales costs, exceeded the $16.3 million net book value of the drilling rigs, both in the aggregate and for each drilling rig, resulting in a gain of $9.6 million.

NOTE 4 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended September 30, 2015			
Basic earnings (loss) per common share	$(205,281)	49,155	$(4.18)
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	—	—
Diluted earnings (loss) per common share	$(205,281)	49,155	$(4.18)
For the three months ended September 30, 2014			
Basic earnings per common share	$67,522	48,650	$1.39
Effect of dilutive stock options, restricted stock, and SARs	—	527	(0.02)
Diluted earnings per common share	$67,522	49,177	$1.37

Table of Contents

Due to the net loss for the three months ended September 30, 2015, approximately 296,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and were excluded from the earnings per share calculation above.

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,	
	2015	2014
Stock options and SARs	261,270	24,500
Average exercise price	$50.34	$73.26

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2015			
Basic earnings (loss) per common share	$(728,024)	49,094	$(14.83)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted earnings (loss) per common share	$(728,024)	49,094	$(14.83)
For the nine months ended September 30, 2014			
Basic earnings per common share	$178,827	48,596	$3.68
Effect of dilutive stock options, restricted stock, and SARs	—	458	(0.03)
Diluted earnings per common share	$178,827	49,054	$3.65

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

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,	
	2015	2014
Stock options and SARs	261,270	49,000
Average exercise price	$50.34	$67.83

Table of Contents

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	September 30, 2015	December 31, 2014
	(In thousands)	
Lease operating expenses	$19,923	$20,709
Interest	17,036	6,654
Employee costs	12,300	31,451
Taxes	11,984	3,284
Third-party credits	2,854	2,825
Other	3,945	5,248
Total accrued liabilities	$68,042	$70,171

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

Long-Term Debt

As of the dates in the table, our long-term debt consisted of the following:

	September 30, 2015	December 31, 2014
	(In thousands)	
Credit agreement with an average interest rate of 4.0% and 2.9% at September 30, 2015 and December 31, 2014, respectively	$261,700	$166,000
6.625% senior subordinated notes due 2021, net of unamortized discount of $3.5 million and $3.8 million at September 30, 2015 and December 31, 2014, respectively	646,534	646,163
Total long-term debt	$908,234	$812,163

Credit Agreement. On April 10, 2015, we amended our Senior Credit Agreement (credit agreement) to extend the maturity date from September 13, 2016 to April 10, 2020. The amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders (currently $550.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current elected commitment amount is $500.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% 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. To date, for this new amendment, we paid $2.6 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. Effective with the October 2015 redetermination, the lenders under our credit agreement decreased our borrowing base from $725.0 million to $550.0 million. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At September 30, 2015, the outstanding borrowings under the credit agreement were $261.7 million.

Table of Contents

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

The credit agreement prohibits, among other things:

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

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

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- 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, 2015, we were in compliance with the covenants in the credit agreement.

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

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

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

Before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2015.

Table of Contents

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2015	December 31, 2014
	(In thousands)	
Asset retirement obligation (ARO) liability	$94,608	$100,567
Capital lease obligations	23,332	25,876
Workers' compensation	16,800	17,997
Separation benefit plans	10,560	11,276
Deferred compensation plan	4,454	4,055
Gas balancing liability	3,623	3,623
Other	410	410
	153,787	163,804
Less current portion	16,806	15,019
Total other long-term liabilities	$136,981	$148,785

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, 2015 (and through 2020) are $16.8 million, $39.2 million, $9.1 million, $8.3 million, and $271.0 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 $3.5 million portion of our capital lease obligations is included in current portion of other long-term liabilities and the non-current portion of $19.8 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of September 30, 2015. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining at September 30, 2015 related to these leases are $9.9 million and $2.9 million, respectively. Annual payments, net of maintenance and interest, average $3.8 million annually through 2021. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

Future payments required under the capital leases at September 30, 2015:

Ending September 30,	Amount (In thousands)
2016	$6,168
2017	6,168
2018	6,168
2019	6,168
2020	6,168
2021 and thereafter	5,311
Total future payments	36,151
Less payments related to:	
Maintenance	9,891
Interest	2,928
Present value of future minimum payments	$23,332

12

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,	
	2015	2014
	(In thousands)	
ARO liability, January 1:	$100,567	$133,657
Accretion of discount	2,599	3,538
Liability incurred	6,505	2,889
Liability settled	(1,933)	(3,936)
Liability sold	(249)	(1,206)
Revision of estimates [1]	(12,881)	(38,263)
ARO liability, September 30:	94,608	96,679
Less current portion	3,481	2,718
Total long-term ARO	$91,127	$93,961

(1) Plugging liability estimates were revised in both 2015 and 2014 to account for changes 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

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. 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. Early adoption of the amendments is permitted for financial statements that have not been previously issued. 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 do not expect the adoption of this guidance will have a material impact on our financial statements.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. 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 it will have on our financial statements.

Table of Contents

NOTE 9 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In millions)			
Recognized stock compensation expense	$2.1	$4.4	$11.2	$12.7
Capitalized stock compensation cost for our oil and natural gas properties	0.7	0.9	2.6	2.7
Tax benefit on stock based compensation	0.8	1.7	4.2	4.9

The remaining unrecognized compensation cost related to unvested awards at September 30, 2015 is approximately $19.1 million, of which $3.4 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 of a year.

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

We did not grant any SARs or stock options during either of the three or nine month periods ending September 30, 2015 and 2014. The following table shows the fair value of restricted stock awards granted to employees and non-employee directors during the nine months ended September 30, 2015 and 2014. There were no shares granted during the three months ended September 30, 2015 and 2014.

	Nine Months Ended September 30,	
	2015	2014
Shares granted:		
Employees	724,442	438,342
Non employee directors	25,848	13,768
	750,290	452,110
Estimated fair value (in millions):		
Employees	$23.6	$22.4
Non employee directors	0.9	0.9
	$24.5	$23.3
Percentage of shares granted expected to be distributed:		
Employees	75 %	90 %
Non employee directors	100 %	100 %

The restricted stock awards granted during the first nine months of 2015 and 2014 are being recognized over a three year vesting period, except for a portion of those awards made to certain executive officers. As to those executive officers, 50% of the shares granted, or 148,081 shares in 2015, 40% of the shares granted, or 71,674 shares in 2014, and 30% of the shares granted, or 57,405 shares in 2013, (the performance shares), will cliff vest in the first half of 2018, 2017, and 2016, respectively. The actual number of performance shares that vest in 2016, 2017, and 2018 will be based on the company’s achievement of certain stock performance measures at the end of the term, and will range from 0% to 150% of the restricted shares granted as performance shares. Based on a probability assessment of the selected performance criteria at September 30, 2015, the participants are estimated to receive none of the 2015, 67%

of the 2014, and 11% of the 2013 performance based shares. Based on this assessment, we reduced our accrual for total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties by $3.0 million. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2015 awards for the first nine months of 2015 was $6.8 million.

Table of Contents

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, 2015, our derivative transactions comprised the following hedges:

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

- Collars. A collar contains a fixed floor price (long put) and a ceiling price (short 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. The change in fair value on all commodity derivatives is reflected in the statement of operations and not in accumulated other comprehensive income (OCI).

At September 30, 2015, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct'15 – Dec'15	Crude oil – swap	1,000 Bbl/day	$95.00	WTI – NYMEX
Oct'15 – Dec'15	Crude oil – collar	2,000 Bbl/day	$58.00 - $64.40	WTI – NYMEX
Oct'15 – Dec'15	Natural gas – swap	40,000 MMBtu/day	$3.98	NYMEX (HH)
Jan'16 - Dec'16	Natural gas – swap	10,000 MMBtu/day	$3.25	NYMEX (HH)
Nov'15 - Dec'16	Natural gas – three-way collar	13,500 MMBtu/day	$2.70 - $2.20 - $3.26	NYMEX (HH)

After September 30, 2015, the following non-designated hedges were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'16 - Jun'16	Crude oil – collar	700 Bbl/day	$44.00 - $54.00	WTI – NYMEX
Jan'16 - Dec'16	Crude oil – three-way collar	700 Bbl/day	$46.50 - $35.00 - $57.00	WTI – NYMEX
Jul'16 - Dec'16	Crude oil – three-way collar (1)	700 Bbl/day	$47.50 - $35.00 - $63.50	WTI – NYMEX
Jan'16 - Dec'16	Natural gas – collar	27,000 MMBtu/day	$2.50 - $3.11	NYMEX (HH)

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

15

Table of Contents

The following table presents 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, 2015	December 31, 2014
		(In thousands)	
Commodity derivatives:			
Current	Current derivative asset	$11,461	$31,139
Long-term	Non-current derivative asset	439	—
Total derivative assets		$11,900	$31,139

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.

For our economic hedges any changes in fair value occurring before maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges in our Unaudited Condensed Consolidated Statements of Operations.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (derivatives not designated as hedging instruments) for the three months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative 2015	2014
		(In thousands)	
Commodity derivatives	Gain on derivatives not designated as hedges(1)	$8,250	$19,841
Total		$8,250	$19,841

(1) Amounts settled during the 2015 and 2014 periods include a gain of $11.1 million and a loss of $1.0 million, respectively.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (derivatives not designated as hedging instruments) for the nine months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative 2015	2014
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges (1)	$12,917	$(9,234)
Total		$12,917	$(9,234)

(1) Amounts settled during the 2015 and 2014 periods include a gain of $32.2 million and a loss of $19.0 million, respectively.

Table of Contents

NOTE 11 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount received from the sale of an asset or paid for transferring a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value. The highest priority is given to Level 1 and the lowest priority is 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. Inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.

- Level 3 - unobservable inputs developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments. We corroborate these inputs based on recent transactions and broker quotes and compare the fair value with actual settlements.

The following tables set forth our recurring fair value measurements:

	September 30, 2015		
	Level 2	Level 3	Net Amounts Presented
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$9,418	$2,482	$11,900
Liabilities	—	—	—
	$9,418	$2,482	$11,900

	December 31, 2014		
	Level 2	Level 3	Net Amounts Presented
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$27,784	$3,355	$31,139
Liabilities	—	—	—
	$27,784	$3,355	$31,139

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.

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 crude oil collars and natural gas 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:

	Commodity Derivatives			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Beginning of period	$207	$(6,081)	$3,355	$(2,595)
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	4,436	5,785	5,324	(2,043)
Settlements	(2,161)	887	(6,197)	5,229
End of period	$2,482	$591	$2,482	$591
Total gains (losses) for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	$2,275	$6,672	$(873)	$3,186

(1) Commodity derivatives are reported in the Unaudited Condensed Consolidated Statements of Operations in gain (loss) on derivatives not designated as hedges.

The following table provides quantitative information about our Level 3 unobservable inputs at September 30, 2015:

Commodity [(1)]	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil collar	$2,300	Discounted cash flow	Forward commodity price curve	$0.01 - $12.80
Natural gas three-way collar	182	Discounted cash flow	Forward commodity price curve	$0.01 - $0.30

(1) The commodity contracts detailed in this category include a non-exchange-traded crude oil collar and a natural gas three-way collar 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, 2015, 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 under 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 these estimates. Using different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At September 30, 2015, 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 has historically approximated its fair value and at September 30, 2015 was $261.7 million. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount, associated with the Notes reported in the Unaudited Condensed Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014 were $646.5 million and

Table of Contents

$646.2 million, respectively. We estimated the fair value of these Notes using quoted marked prices at September 30, 2015 and December 31, 2014 which were $528.1 million and $605.5 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:

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

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

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. Our oil and natural gas properties outside the United States are not significant.

Table of Contents

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

	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(In thousands)			
Revenues:				
Oil and natural gas	$96,619	$188,471	$309,944	$575,176
Contract drilling	68,426	147,866	234,177	407,905
Elimination of inter-segment revenue	(3,404)	(27,214)	(19,063)	(66,375)
Contract drilling net of inter-segment revenue	65,022	120,652	215,114	341,530
Gas gathering and processing	66,836	113,467	209,803	350,181
Elimination of inter-segment revenue	(16,084)	(21,616)	(52,922)	(72,494)
Gas gathering and processing net of inter-segment revenue	50,752	91,851	156,881	277,687
Total revenues	$212,393	$400,974	$681,939	$1,194,393
Operating income (loss):				
Oil and natural gas	$(329,152)	$69,597	$(1,163,358)	$240,239
Contract drilling	15,281	31,365	40,550	83,311
Gas gathering and processing	(538)	3,021	(718)	9,549
Total operating income (loss) (1)	(314,409)	103,983	(1,123,526)	333,099
General and administrative	(7,643)	(10,172)	(26,637)	(30,409)
Gain (loss) on disposition of assets	(7,230)	(529)	(6,270)	9,092
Gain (loss) on derivatives not designated as hedges	8,250	19,841	12,917	(9,234)
Interest expense, net	(8,286)	(4,280)	(23,482)	(12,201)
Other	16	(68)	38	3
Income (loss) before income taxes	$(329,302)	$108,775	$(1,166,960)	$290,350

(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 (loss) on non-designated hedges, interest expense, other income (loss), or income taxes.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying unaudited condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of September 30, 2015, and the related unaudited condensed consolidated statements of operations for the three month and nine month periods ended September 30, 2015 and 2014 and the unaudited condensed consolidated statement of cash flows for the nine month periods ended September 30, 2015 and 2014. These interim financial statements are the responsibility of the Company’s management.

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

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2014, and the related consolidated statements of operations, shareholder’s equity and of cash flows for the year then ended (not presented herein), and in our report dated February 24, 2015, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2014, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
November 3, 2015

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

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

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

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

General

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

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

Business Outlook

As discussed in other parts of this report, the success of our consolidated business, and that of each of our three operating segments, depends, to a large extent, on: the prices we receive for and the amount of our oil, NGLs, and natural gas production; the demand for oil, NGLs, and natural gas; and, the demand for our drilling rigs which influences the amounts we can charge for those drilling rigs. Although all of our current operations are within the United States, events outside the United States can affect us and our industry.

Both within the United States and the world, deteriorating commodity prices have brought about significant and immediate changes affecting our industry and us. The decline in commodity prices has caused us (and other oil and gas companies) to reduce our level of drilling activity and spending. When drilling activity and spending decline for any sustained period of time the number of our drilling rigs working and the rates we charge for them also decline. In addition, lower commodity prices for any sustained period of time could affect the liquidity condition of some of our industry partners and customers, which might limit their ability to meet their financial obligations to us.

It is uncertain how long the current depressed prices for oil and natural gas products will continue. As noted elsewhere in this report, commodity prices are subject to several factors most of which are beyond our control.

The impact on our business and financial results because of the reduction in oil and NGLs (and to a lesser extent natural gas) prices is uncertain in the long term, but in the short term, it has had several consequences for us, including:

- In March 2015, we incurred a non-cash ceiling test write-down of our oil and natural gas properties of $400.6 million pre-tax ($249.4 million net of tax), in June 2015, we incurred a non-cash ceiling test write-down of our oil and natural gas properties of $410.5 million pre-tax ($255.6 million net of tax), and in September 2015, we incurred

Table of Contents

a non-cash ceiling test write-down of our oil and natural gas properties of $329.9 million pre-tax ($205.4 million net of tax). We expect to incur a non-cash ceiling test write-down in the fourth quarter of 2015. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward reserve revisions, reserve additions, and tax attributes. Subject to these numerous factors and inherent limitations, holding these factors constant and only adjusting the 12-month average price to an estimated fourth quarter ending average (holding October 2015 prices constant for the remaining two months of 2015), we currently anticipate that we could recognize an impairment in the fourth quarter of 2015 of approximately $260 million pre-tax. After the end of the year, the impact of the significantly higher commodity prices from 2014 used in the ceiling test 12-month average price calculation will lessen as those prices will no longer be used in the ceiling test.

- The majority of our drilling rig customers have significantly reduced their drilling budgets for 2015, resulting in a significant reduction in the average utilization of our drilling rig fleet. At December 31, 2014, we had 75 rigs operating, at September 30, 2015, this number was 29.
- Due to the low NGLs prices, we are operating our processing facilities in full ethane rejection mode which reduces the amount of liquids sold. As long as NGLs prices continue to be depressed, we expect to continue operating in full ethane rejection mode. As low commodity prices continue, we expect the reductions in drilling activity around our systems will reduce the number of new wells available to connect to our systems and result in lower processed volumes as production from wells previously connected naturally decline.
- Effective with the October 2015 redetermination, the lenders of our credit agreement decreased our borrowing base from $725.0 million to $550.0 million. This new amount is above the $500.0 million commitment we have elected under the credit agreement.

Executive Summary

Oil and Natural Gas

Third quarter 2015 production from our oil and natural gas segment was 5,053,000 barrels of oil equivalent (Boe) which was essentially unchanged from the second quarter of 2015 and an increase of 10% over the third quarter of 2014. The increases over the third quarter of 2014 were primarily from production associated with new wells drilled in 2014 and 2015.

Third quarter 2015 oil and natural gas revenues decreased 10% from the second quarter of 2015 and decreased 49% from third quarter of 2014, respectively. The respective decreases were due primarily to lower oil, NGLs, and natural gas prices.

Our oil prices for the third quarter of 2015 decreased 8% from the second quarter of 2015 and decreased 44% from the third quarter of 2014. Our NGLs prices decreased 27% and 71% from the second quarter of 2015 and third quarter of 2014, respectively. Our natural gas prices were essentially unchanged from the second quarter of 2015 and decreased 28% from the third quarter of 2014.

Operating cost per Boe produced for the third quarter of 2015 decreased 16% from the second quarter of 2015 and decreased 28% from the third quarter of 2014. Costs decreased between the third and second quarters of 2015 primarily due to lower lease operating expenses, workover expenses, and gross production taxes from lower sales revenue and more gross production tax credits. The decrease from the third quarter of 2014 was primarily due to lower gross production tax from lower sales revenue, lower lease operating expense, and lower general and administrative expenses partially offset by higher saltwater disposal expense.

Table of Contents

For the remainder of 2015, we have derivative contracts covering approximately 3,000 Bbls per day of oil production. For the month of October, we have hedged approximately 40,000 MMBtu per day of natural gas production and for November and December, we have hedged approximately 53,500 MMBtu per day of natural gas production. For 2016, we have hedged approximately 1,400 Bbls per day of oil production and 50,500 MMbtu per day of natural gas production. We currently have the following outstanding hedges by contract type:

Swaps:

Commodity	Term	Volume	Weighted Average Fixed Price
Crude oil	Oct'15 - Dec'15	1,000 Bbl/day	$95.00
Natural gas	Oct'15 - Dec'15	40,000 MMBtu/day	$3.98
Natural gas	Jan'16 - Dec'16	10,000 MMBtu/day	$3.25

Collars:

Commodity	Term	Volume	Weighted Average Floor Price	Weighted Average Ceiling Price
Crude oil	Oct'15 - Dec'15	2,000 Bbl/day	$58.00	$64.40
Crude oil	Jan'16 - Jun'16	700 Bbl/day	$44.00	$54.00
Natural gas	Jan'16 - Dec'16	27,000 MMBtu/day	$2.50	$3.11

Three-Way Collars:

Commodity	Term	Volume	Weighted Average Floor Price	Weighted Average Subfloor Price	Weighted Average Ceiling Price
Crude oil	Jan'16 - Dec'16	700 Bbl/day	$46.50	$35.00	$57.00
Crude oil[(1)]	Jul'16 - Dec'16	700 Bbl/day	$47.50	$35.00	$63.50
Natural gas	Nov'15 - Dec'16	13,500 MMBtu/day	$2.70	$2.20	$3.26

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

As of September 30, 2015, we completed drilling 42 gross wells (28.29 net wells). For all of 2015, we plan to participate in the drilling of approximately 50-60 gross wells. Excluding acquisitions and ARO liability, our estimated 2015 capital expenditures for this segment are $278.5 million. Our current 2015 production guidance is approximately 19.4 to 19.8 MMBoe, an increase of 6% to 8% over 2014, although actual results continue to be subject to many factors.

Contract Drilling

The average number of drilling rigs we operated for the third quarter of 2015 was 31.2 compared to 30.7 and 79.1 in the second quarter of 2015 and the third quarter of 2014, respectively. Late in the fourth quarter of 2014, the number of our drilling rigs operating started to decline and has continued to decline throughout the first six months of 2015 due to lower commodity prices and operators reducing their drilling budgets. As of September 30, 2015, 29 drilling rigs were operating.

Revenue for the third quarter of 2015 increased 18% over the second quarter of 2015 and decreased 46% from the third quarter of 2014. The increase over second quarter of 2015 was primarily due to early contract termination revenue. The third quarter of 2015 included early contract termination revenue of $11.4 million compared to $1.6 million in the second quarter of 2015. There was no early termination revenue during the third quarter of 2014. The decrease from the third quarter of 2014 was primarily due to fewer rigs operating.

Dayrates for the third quarter of 2015 averaged $18,800, a 5% and 6% decrease from the second quarter of 2015 and third quarter of 2014, respectively. The decreases were due to downward pressure on dayrates with lower demand.

Operating costs for the third quarter of 2015 decreased 3% and 47% from the second quarter of 2015 and the third quarter of 2014, respectively. The decreases from the second quarter were from reduced indirect, workers' compensation, and general and administrative expenses while the decreases from the quarter of 2014 were due primarily to fewer rigs operating.

Table of Contents

Low commodity prices continue to curtail our customer drilling budgets and demand for our drilling rigs. As a result, we are experiencing reduced drilling rig utilization. Almost all of our working drilling rigs in 2015 have been drilling horizontal or directional wells. Our drilling rig fleet consists of drilling rigs capable of meeting our customers' demands whether it be for oil, natural gas, or NGLs and whether it be for shallow, deep, vertical, or horizontal type drilling. Current and future demand for drilling rigs and the availability of drilling rigs to meet that demand will affect our future dayrates.

As of September 30, 2015, we had 29 drilling rigs operating. Of those, 18 are on spot market contracts and 11 are on term drilling contracts, with original terms ranging from six months to two years. One term contract is up for renewal in the fourth quarter of 2015, seven are up for renewal in 2016, and three are up for renewal in 2017. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate. Some operators who had signed term contracts have opted to release the drilling rig and pay an early termination penalty for the remaining term of the contract. During the third quarter, we were notified of a customer's intent to terminate two of our BOSS drilling rigs term contracts. Since then, the customer has decided to keep one of the BOSS drilling rigs through its remaining term and the other has been contracted by another third party operator. During the first nine months of 2015, we recorded $25.7 million in early termination fees.

We have completed our current new BOSS drilling rig program for 2015. Eight new BOSS drilling rigs have been placed into service. Some of the long lead time components for three additional BOSS drilling rigs were ordered during 2014 and will be delivered in the next twelve months. Currently, we do not have any contracts to build new BOSS drilling rigs. Our estimated 2015 capital expenditures for this segment are $86.1 million.

Mid-Stream

Third quarter 2015 liquids sold per day decreased 3% from the second quarter of 2015 and decreased 25% from the third quarter of 2014. The decrease from the second quarter of 2015 was due to more effectively operating our processing facilities in full ethane rejection mode. The decrease from the third quarter of 2014 was due to operating in ethane ejection mode in 2015. For the third quarter of 2015, gas processed per day were essentially unchanged from the second quarter of 2015 and increased 10% over the third quarter of 2014. The increase over the third quarter of 2014 was primarily due to connecting new wells to both existing and newly constructed systems to replace production declines from wells already connected. For the third quarter of 2015, gas gathered per day decreased 2% from the second quarter of 2015 due to general declines in wells and increased 12% over the third quarter of 2014 due to additional wells added to our systems.

NGLs prices in the third quarter of 2015 decreased 12% from the prices received in the second quarter of 2015 and decreased 53% from the prices received in the third quarter of 2014. Because certain contracts used by our mid-stream segment for NGLs transactions are percent of proceeds (POP) contracts–under which we receive a share of the proceeds from the sale of the NGLs–our revenues from those POP contracts fluctuate based on the price of NGLs.

Operating costs for the third quarter of 2015 decreased 1% from the second quarter of 2015 and decreased 49% from the third quarter of 2014 due primarily to lower gas purchase prices.

With the completion of the connection of the Buffalo Wallow gathering system to our Hemphill County, Texas processing facility in January of this year, we are currently processing all the Buffalo Wallow production at our Hemphill facility. The average throughput volume for the third quarter of 2015 at this facility was approximately 88 MMcf per day which includes the Buffalo Wallow production. The Hemphill facility has total processing capacity of approximately 135 MMcf per day.

During the third quarter of 2015, we connected six new wells to our Bellmon system in north central Oklahoma. For the year through September, we have connected a total of 38 new wells to this system. Total processing capacity at this facility is 90 MMcf per day from two cryogenic processing plant skids. During the third quarter of 2015, we had an average throughput volume of 41 MMcf per day at this system. Upgrades are being completed that will allow us to begin gathering and processing additional production we believe will be available in the near future.

At our Segno gathering facility located in southeast Texas, we continue to work on several upgrade projects to increase our gathering capacity up 120 MMcf per day. Most of these projects have been completed but we are continuing to work on looping a section of pipeline that will allow us to move additional volume and reduce pipeline pressure. The majority of the right of way for this line looping project has been acquired and we expect to begin pipeline construction in the fourth quarter of 2015. This project is expected to be completed and operational by the end of 2015. We connected four new wells to this gathering system in the third quarter of 2015 and have connected a total of 11 wells to this system since the first of the year. The average daily throughput volume for the third quarter is approximately 75 MMcf per day.

Table of Contents

In the Appalachian region, we are continuing to work on the expansion of our Pittsburgh Mills gathering system. This expansion project extends our system into Butler County, Pennsylvania and will provide us another outlet for our gas. We have completed the seven-mile pipeline construction and are currently gathering gas from new well pads in the area. We are completing the construction of the compressor station and it is expected to be operational in the fourth quarter of this year. This expansion into Butler County, Pennsylvania allows us the ability to connect additional well pads which are scheduled to be connected to our system in the first half of 2016.

Also in the Appalachian area, we are completing the construction of our new Snow Shoe gathering system in Centre County, Pennsylvania. This is a fee-based gathering system consisting of approximately seven miles of 16” and 24” pipeline and a related compressor station. The construction of the pipeline has been completed. Since the compressor station will not be required initially to flow gas, we are going to postpone the construction of the compressor station until it is required. We will reevaluate the construction of the compressor station as warranted. We expect this system will be operational and flowing gas before the end of the year.

Our 2015 estimated capital expenditures for the midstream segment are $59.7 million.

Financial Condition and Liquidity

Summary

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

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

	Nine Months Ended September 30, 2015	2014	% Change
	(In thousands except percentages)		
Net cash provided by operating activities	$381,482	$549,527	(31)%
Net cash used in investing activities	(474,190)	(636,761)	(26)%
Net cash provided by financing activities	92,553	69,536	33%
Net decrease in cash and cash equivalents	$(155)	$(17,698)	

Cash Flows from Operating Activities

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

Net cash provided by operating activities in the first nine months of 2015 decreased by $168.0 million from the first nine months of 2014 due primarily to lower revenues due to lower commodity prices and lower rig utilization partially offset by $25.7 million we recorded in early termination fees and by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

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

Table of Contents

Cash flows used in investing activities decreased by $162.6 million for the first nine months of 2015 compared to the first nine months of 2014. The change was due primarily to a decrease in capital expenditures partially offset by a decrease in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $23.0 million for the first nine months of 2015 compared to the first nine months of 2014. This increase was primarily due to borrowings under our credit agreement offset partially by a decrease in our book overdrafts (checks issued but not presented to our bank for payment before the end of the period).

At September 30, 2015, we had unrestricted cash totaling $0.9 million and had borrowed $261.7 million of the $500.0 million we had elected to then have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of September 30, 2015 and 2014 and for the nine months ended September 30, 2015 and 2014:

	September 30, 2015	2014	% Change [(1)]
	(In thousands except percentages)		
Working capital	$(31,681)	$(131,212)	76%
Long-term debt	$908,234	$676,843	34%
Shareholders' equity	$1,617,957	$2,367,500	(32)%
Net income (loss)	$(728,024)	$178,827	NM

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

Table of Contents

The following table summarizes certain operating information:

	Nine Months Ended September 30, 2015	2014	% Change
Oil and Natural Gas:			
Oil production (MBbls)	2,996	2,801	7 %
NGLs production (MBbls)	3,954	3,376	17 %
Natural gas production (MMcf)	49,650	43,424	14 %
Average oil price per barrel received	$51.46	$92.44	(44)%
Average oil price per barrel received excluding derivatives	$46.80	$96.34	(51)%
Average NGLs price per barrel received	$9.83	$33.05	(70)%
Average NGLs price per barrel received excluding derivatives	$9.83	$33.05	(70)%
Average natural gas price per Mcf received	$2.76	$3.99	(31)%
Average natural gas price per Mcf received excluding derivatives	$2.39	$4.17	(43)%
Contract Drilling:			
Average number of our drilling rigs in use during the period	37.3	73.5	(49)%
Total number of drilling rigs available for use at the end of the period	94	119	(21)%
Average dayrate	$19,669	$19,876	(1)%
Mid-Stream:			
Gas gathered—Mcf/day	351,619	316,658	11 %
Gas processed—Mcf/day	186,929	160,373	17 %
Gas liquids sold—gallons/day	582,760	748,805	(22)%
Number of natural gas gathering systems [1]	25	38	(34)%
Number of processing plants	13	14	(7)%

(1) In 2015, our mid-stream segment transferred 11 natural gas gathering systems to our oil and natural gas segment.

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 $31.7 million and $131.2 million as of September 30, 2015 and 2014, respectively. This is primarily from the timing of our accounts payable associated with our capital expenditures. Our credit agreement is used primarily for working capital and capital expenditures. At September 30, 2015, we had borrowed $261.7 million of the $500.0 million currently available to us under our credit agreement. The effect of our derivative contracts increased working capital by $11.5 million as of September 30, 2015 and increased working capital by $4.0 million as of September 30, 2014.

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. 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 impact on the prices we will receive.

Based on our first nine months of 2015 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 $526,000 per month ($6.3 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 2015 was $2.76 compared to $3.99 for the first nine months of 2014. Based on our first nine months of 2015 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $321,000 per month ($3.8 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 $420,000 per month ($5.0 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2015, our average oil price per barrel received, including the effect of derivatives, was $51.46 compared with an average oil price, including the effect of derivatives, of $92.44 in the first nine months of 2014 and our first nine months of 2015 average NGLs price per barrel received was $9.83 compared with an average NGLs price per barrel of $33.05 in the first nine months of 2014.

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 2015, the unamortized cost of our oil and gas properties exceeded the ceiling of our proved oil, NGLs, and natural gas reserves. As a result, we recorded in March of 2015 a non-cash ceiling test write down of $400.6 million pre-tax ($249.4 million, net of tax) and in June of 2015, we recorded a non-cash ceiling test write-down of $410.5 million pre-tax ($255.6 million, net of tax). Then in September of 2015, we recorded a a non-cash ceiling test write-down of $329.9 million pre-tax ($205.4 million, net of tax). At September 30, 2015, the 12-month average unescalated prices were $59.21 per barrel of oil, $23.91 per barrel of NGLs, and $3.06 per Mcf of natural gas, then adjusted for price differentials.

We expect to incur a non-cash ceiling test write-down in the fourth quarter of 2015. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward reserve revisions, reserve additions, and tax attributes. Subject to these numerous factors and inherent limitations, holding these factors constant and only adjusting the 12-month average price to an estimated fourth quarter ending average (holding October 2015 prices constant for the remaining two months of 2015), we currently anticipate that we could recognize an impairment in the fourth quarter of 2015 of approximately $260 million pre-tax. The estimated fourth quarter 2015 impairment is partially the result of a decrease in our proved undeveloped reserves of approximately 49%. This decrease was primarily due to certain locations no longer being economical under the adjusted 12-month average price for the fourth quarter. Based on this estimated 12-month average price, we would eliminate those locations from our future development plans. After the end of the year, the impact of the significantly higher commodity prices from 2014 used in the ceiling test 12-month average price calculation will lessen as those prices will no longer be used in the ceiling test. Given the uncertainty associated with the factors used in calculating our estimate of both our future period ceiling test write-down and the decrease in our undeveloped reserves, these estimates should not necessarily be construed as indicative of our future development plans or financial results.

Price declines can also adversely affect future semi-annual determinations of the amount we can borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects. Effective with the October 2015 redetermination, the lenders under our credit agreement decreased our borrowing base from $725.0 million to $550.0 million. This new amount is above the $500.0 million commitment we have elected under the credit agreement.

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 and the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Although our rig personnel are a key component to the overall success of our drilling services, with the present conditions existing in the drilling industry we do not anticipate increases in the compensation paid to those personnel in the near term.

Low commodity prices continue to curtail our customer drilling budgets and demand for our drilling rigs. As a result, we are experiencing reduced drilling rig utilization. Almost all of our working drilling rigs in 2015 have been drilling horizontal or directional wells. Our drilling rig fleet consists of drilling rigs capable of meeting our customers' demands whether it be for oil, natural gas, or NGLs and whether it be for shallow, deep, vertical, or horizontal type drilling. Current and future demand for drilling rigs and the availability of drilling rigs to meet that demand will affect our future dayrates. For the first nine months of 2015, our average dayrate was $19,669 per day compared to $19,876 per day for the first nine months of 2014. The average number of our drilling rigs used in the first nine months of 2015 was 37.3 drilling rigs compared with 73.5 drilling rigs in the first nine months of 2014. Based on the average utilization of our drilling rigs during the first nine months of 2015, a $100 per day change in dayrates has a $3,730 per day ($1.4 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 eliminated revenue of $19.1 million and $66.4 million for the first nine months of 2015 and 2014, respectively, from our contract drilling segment and eliminated the associated operating expense of $15.4 million and $46.4 million during the first nine months of 2015 and 2014, respectively, yielding $3.7 million and $20.0 million during the first nine months of 2015 and 2014, respectively, as a reduction to the carrying value of our oil and natural gas properties.

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment and based on estimated market value from third party assessments (Level 3 fair value measurement), we recorded a write-down of approximately $74.3 million pre-tax. During the first quarter of 2015, we sold one of these drilling rigs to an unaffiliated third party. The proceeds of this sale, less costs to sell, exceeded the $0.3 million net book value of the drilling rig resulting in a gain of $7,900. During the second quarter, we recorded an additional write-down on the remaining drilling rigs and other equipment of approximately $8.3 million pre-tax based on the estimated market value from similar auctions. During the third quarter we sold the remaining 30 drilling rigs and most of the equipment in an 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. The equipment that was not sold at the auction will be sold within the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.3 million.

Our goodwill is all related to our contract drilling segment and goodwill is not amortized, but an impairment test is performed at least annually as of December 31 or more frequently if events or changes in circumstances indicate that the asset might be impaired. The decline in commodity prices has worsened through 2015 resulting in reductions in the number of our drilling rigs working and the rates we charge for them and given this triggering event, we performed impairment testing on our goodwill. Based on the results of our assessment, no goodwill impairment was recorded as of September 30, 2015. A period of sustained reduced commodity prices could result in a non-cash goodwill impairment in future periods.

Mid-Stream Operations

Our mid-stream segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 13 processing plants, 25 gathering systems, and approximately 1,450 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 2015 and 2014, our mid-stream operations purchased $47.2 million and $65.7 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $5.7 million and $6.8 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 351,619 Mcf per day in the first nine months of 2015 compared to 316,658 Mcf per day in the first nine months of 2014. It processed an average of 186,929 Mcf per day in the first nine months of 2015 compared to 160,373 Mcf per day in the first nine months of 2014. The amount of NGLs sold was 582,760 gallons per day in the first nine months of 2015 compared to 748,805 gallons per day in the first nine months of 2014. Gas gathering volumes per day in the first nine months of 2015 increased 11% compared to the first nine months of

2014 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes for the first nine months of 2015 increased 17% over the first nine months of 2014 due primarily to new wells connected. NGLs sold decreased 22% from the comparative period due to being in ethane rejection mode.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On April 10, 2015, we amended our Senior Credit Agreement (credit agreement) to extend the maturity date from September 13, 2016 to April 10, 2020. The amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders (currently $550.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current elected commitment amount is $500.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% 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. To date, for this new amendment, we paid $2.6 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

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	%
Wells Fargo Bank, N.A.	8	%
Comerica Bank	8	%
CIBC	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. Effective with the October 2015 redetermination, the lenders under our credit agreement decreased our borrowing base from $725.0 million to $550.0 million. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At September 30, 2015 and October 23, 2015, borrowings were $261.7 million and $273.0 million, respectively.

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

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; and
- 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, 2015, we were in compliance with the covenants in the credit agreement.

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

Table of Contents

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

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

Before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2015.

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 42 gross wells (28.29 net wells) in the first nine months of 2015 compared to 130 gross wells (85.45 net wells) in the first nine months of 2014. Total capital expenditures for oil and gas properties on the full cost method for the first nine months of 2015, excluding an $8.6 million reduction in the ARO liability, totaled $220.0 million. Total capital expenditures for the first nine months of 2014, excluding a $40.5 million reduction in the ARO liability, totaled $572.9 million.

Currently we plan to participate in drilling approximately 50-60 gross wells in 2015 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $278.5 million. Whether we can drill the full number of wells planned depends on several factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment and based on estimated market value from third party assessments (Level 3 fair value measurement), we recorded a write-down of approximately $74.3 million pre-tax. During the first quarter of 2015, we sold one of these drilling rigs to an unaffiliated third party. The proceeds of this sale, less costs to sell, exceeded the $0.3 million net book value of the drilling rig resulting in a gain of $7,900. During the second quarter, we recorded an additional write-down on the remaining drilling rigs and other equipment of approximately $8.3 million pre-tax based on the estimated market value from similar auctions. During the third quarter we sold the remaining 30 drilling rigs and most of the equipment in an 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. The remaining equipment that was not sold at the auction will be sold within the next twelve months and remain classified as assets held for sale. The net book value of those assets is $5.3 million.

We have completed our current new BOSS drilling rig program for 2015. Eight new BOSS drilling rigs have been placed into service. Some of the long lead time components for three additional BOSS drilling rigs were ordered during 2014 and will be delivered in the next twelve months. Currently, we do not have any contracts to build new BOSS drilling rigs.

Table of Contents

Our estimated 2015 capital expenditures for this segment are \$86.1 million. At September 30, 2015, we had commitments to purchase approximately \$6.5 million for drilling equipment within the next year. We have spent \$81.6 million for capital expenditures, including \$57.8 million for the BOSS drilling rigs during the first nine months of 2015, compared to \$121.3 million for capital expenditures, including \$66.0 million for the BOSS drilling rigs, during the first nine months of 2014.

Mid-Stream Acquisitions and Capital Expenditures. With the completion of the connection of the Buffalo Wallow gathering system to our Hemphill County, Texas processing facility in January of this year, we are currently processing all the Buffalo Wallow production at our Hemphill facility. The average throughput volume for the third quarter of 2015 at this facility was approximately 88 MMcf per day which includes the Buffalo Wallow production. The Hemphill facility has total processing capacity of approximately 135 MMcf per day.

During the third quarter of 2015, we connected six new wells to our Bellmon system in north central Oklahoma. For the year through September, we have connected a total of 38 new wells to this system. Total processing capacity at this facility is 90 MMcf per day from two cryogenic processing plant skids. During the third quarter of 2015, we had an average throughput volume of 41 MMcf per day at this system. Upgrades are being completed that will allow us to begin gathering and processing additional production we believe will be available in the near future.

At our Segno gathering facility located in southeast Texas, we continue to work on several upgrade projects to increase our gathering capacity up 120 MMcf per day. Most of these projects have been completed but we are continuing to work on looping a section of pipeline that will allow us to move additional volume and reduce pipeline pressure. The majority of the right of way for this line looping project has been acquired and we expect to begin pipeline construction in the fourth quarter of 2015. This project is expected to be completed and operational by the end of 2015. We connected four new wells to this gathering system in the third quarter of 2015 and have connected a total of 11 wells to this system since the first of the year. The average daily throughput volume for the third quarter is approximately 75 MMcf per day.

In the Appalachian region, we are continuing to work on the expansion of our Pittsburgh Mills gathering system. This expansion project extends our system into Butler County, Pennsylvania and will provide us another outlet for our gas. We have completed the seven-mile pipeline construction and are currently gathering gas from new well pads in the area. We are completing the construction of the compressor station and it is expected to be operational in the fourth quarter of this year. This expansion into Butler County, Pennsylvania allows us the ability to connect additional well pads which are scheduled to be connected to our system in the first half of 2016.

Also in the Appalachian area, we are completing the construction of our new Snow Shoe gathering system in Centre County, Pennsylvania. This is a fee-based gathering system consisting of approximately seven miles of 16” and 24” pipeline and a related compressor station. The construction of the pipeline has been completed. Since the compressor station will not be required initially to flow gas, we are going to postpone the construction of the compressor station until it is required. We will reevaluate the construction of the compressor station as warranted. We expect this system will be operational and flowing gas before the end of the year.

During the first nine months of 2015, our mid-stream segment incurred \$43.9 million in capital expenditures as compared to \$29.2 million, excluding \$28.2 million for capital leases added during the first nine months of 2014. Our 2015 estimated capital expenditures for the midstream segment are \$59.7 million.

Table of Contents

Contractual Commitments

At September 30, 2015, 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]	$1,201,186	$53,531	$107,061	$363,813	$676,781
Operating leases [2]	4,742	3,716	996	30	—
Capital lease interest and maintenance[3]	12,819	2,655	4,874	4,253	1,037
Drill pipe, drilling components, and equipment purchases [4]	6,525	6,525	—	—	—
Enterprise Resource Planning software obligations [5]	1,911	1,425	486	—	—
Total contractual obligations	$1,227,183	$67,852	$113,417	$368,096	$677,818

(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, 2015 interest rates of 6.625% for the Notes and 4.0% for the credit agreement.

(2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through July, 2019. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are $9.9 million and $2.9 million, respectively.

(4) We have committed to pay $6.5 million for drilling rig components, drill pipe, and related equipment over the next twelve months.

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

Table of Contents

At September 30, 2015, 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)	$4,454	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$10,560	$2,231	Unknown	Unknown	Unknown
Asset retirement liability (3)	$94,608	$3,481	$38,022	$8,272	$44,833
Gas balancing liability (4)	$3,623	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability(6)	$16,800	$7,580	$2,334	$1,153	$5,733
Capital leases obligations (7)	$23,332	$3,514	$7,463	$8,083	$4,272
Other	$410	Unknown	$410	Unknown	Unknown

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(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death, or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Unaudited Condensed Consolidated Balance Sheets, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Currently there are no participants in the Senior Plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under "Accounting for Asset Retirement Obligations," we record the discounted fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2011. One of our subsidiaries serves as the general partner of each of these programs. Effective December 31, 2014, The Unit 1984 Oil and Gas Limited Partnership dissolved. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions

commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $118,000 and $37,000 during the first nine months of 2015 and 2014, respectively.

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

(7) The amount includes commitments under capital lease arrangements for compressors in our mid-stream segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production. Any change in fair value on all commodity derivatives we have entered into are reflected in the statement of operations and not in accumulated other comprehensive income.

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, 2015, based on our third quarter 2015 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Q4 2015		2016	
Daily oil production	29	%	—	%
Daily natural gas production	27	%	13	%

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

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our September 30, 2015 evaluation, we believe the risk of non-performance by our counterparties is not material. At September 30, 2015, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	September 30, 2015 (In millions)
Bank of Montreal	$7.8
Bank of America Merrill Lynch	2.3
CIBC	1.6
Scotiabank	0.2
Total assets	$11.9

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, 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. At September 30, 2014, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $4.0 million and $0.7 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 not designated as hedges 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,	
	2015	2014	2015	2014
	(In thousands)			
Gain (loss) on derivatives not designated as hedges:				
Gain (loss) on derivatives not designated as hedges, included are amounts settled during the period of $11,074, ($1,029), $32,156, and ($18,984), respectively	$8,250	$19,841	$12,917	$(9,234)
	$8,250	$19,841	$12,917	$(9,234)

Stock and Incentive Compensation

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. We have elected to use an ERISA governed occupational injury benefit plan to cover our Texas based drilling operations in lieu of covering them under Texas workers' compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles, or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships

We are the general partner of 15 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision, and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. For each of the first nine months of 2015 and 2014, the total we received for all of these fees was $0.3 million and $0.4 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

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. 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. Early adoption of the amendments is permitted for financial statements that have not been previously issued. 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 do not expect the adoption of this guidance will have a material impact on our financial statements.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. 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 it will have on our financial statements.

Table of Contents

Results of Operations

Quarter Ended September 30, 2015 versus Quarter Ended September 30, 2014

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

	Quarter Ended September 30,		Percent
	2015	2014	Change [1]
	(In thousands unless otherwise specified)		
Total revenue	$212,393	$400,974	(47)%
Net income (loss)	$(205,281)	$67,522	NM
Oil and Natural Gas:			
Revenue	$96,619	$188,471	(49)%
Operating costs excluding depreciation, depletion, amortization, and impairment	$38,688	$48,841	(21)%
Depreciation, depletion, and amortization	$57,159	$70,033	(18)%
Impairment of oil and natural gas properties	$329,924	$—	NM
Average oil price received (Bbl)	$50.87	$91.57	(44)%
Average NGLs price received (Bbl)	$8.74	$30.11	(71)%
Average natural gas price received (Mcf)	$2.66	$3.68	(28)%
Oil production (Bbl)	950,000	1,040,000	(9)%
NGLs production (Bbl)	1,339,000	1,147,000	17 %
Natural gas production (Mcf)	16,586,000	14,543,000	14 %
Depreciation, depletion, and amortization rate (Boe)	$10.98	$14.88	(26)%
Contract Drilling:			
Revenue	$65,022	$120,652	(46)%
Operating costs excluding depreciation and impairment	$35,486	$66,727	(47)%
Depreciation	$14,255	$22,560	(37)%
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	31.2	79.1	(61)%
Average dayrate on daywork contracts	$18,800	$20,070	(6)%
Mid-Stream:			
Revenue	$50,752	$91,851	(45)%
Operating costs excluding depreciation and amortization	$40,314	$78,558	(49)%
Depreciation and amortization	$10,976	$10,272	7 %
Gas gathered—Mcf/day	357,427	319,692	12 %
Gas processed—Mcf/day	185,625	169,357	10 %
Gas liquids sold—gallons/day	579,556	771,334	(25)%
Corporate and other:			
General and administrative expense	$7,643	$10,172	(25)%
Loss on disposition of assets	$(7,230)	$(529)	NM
Other income (expense):			
Interest expense, net	$(8,286)	$(4,280)	94 %
Gain on derivatives not designated as hedges	$8,250	$19,841	(58)%

Other	$16	$(68)	124 %
Income tax expense (benefit)	$(124,021)	$41,253	NM
Average long-term debt outstanding	$920,020	$662,063	39 %
Average interest rate	5.3 %	6.6 %	(20)%

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

Oil and Natural Gas

Oil and natural gas revenues decreased $91.9 million or 49% in the third quarter of 2015 as compared to the third quarter of 2014 due primarily to lower oil, natural gas, and NGLs prices. In the third quarter of 2015, as compared to the third quarter of 2014, oil production decreased 9%, NGLs production increased 17%, and natural gas production increased 14%. Average oil prices decreased 44% to $50.87 per barrel, average natural gas prices decreased 28% to $2.66 per Mcf, and average NGLs prices decreased 71% to $8.74 per barrel.

Oil and natural gas operating costs decreased $10.2 million or 21% between the comparative third quarters of 2015 and 2014 due primarily to lower gross production taxes due to lower sales revenues and more gross production tax credits, lease operating expenses, and general and administrative expenses partially offset by higher saltwater disposal expenses.

Depreciation, depletion, and amortization ("DD&A") decreased $12.9 million or 18% due primarily to a 26% decrease in our DD&A rate partially offset by a 10% increase in equivalent production. The decrease in our DD&A rate in the third quarter of 2015 compared to the third quarter of 2014 resulted primarily from the effect of the ceiling test write-downs in the fourth quarter of 2014, the first quarter of 2015, and the second quarter of 2015. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

During the 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).

Contract Drilling

Drilling revenues decreased $55.6 million or 46% in the third quarter of 2015 versus the third quarter of 2014. The decrease was due primarily to a 61% decrease in the average number of drilling rigs in use partially offset by $11.4 million for fees on contracts terminated early in the third quarter of 2015. Average drilling rig utilization decreased from 79.1 drilling rigs in the third quarter of 2014 to 31.2 drilling rigs in the third quarter of 2015.

Drilling operating costs decreased $31.2 million or 47% between the comparative third quarters of 2015 and 2014. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased $8.3 million or 37% also due primarily to fewer drilling rigs operating and from 31 rigs being placed out of service at the end of 2014.

Mid-Stream

Our mid-stream revenues decreased $41.1 million or 45% in the third quarter of 2015 as compared to the third quarter of 2014 due primarily from the average price for natural gas sold decreasing 30%, the average price for NGLs sold decreasing 53%, and NGLs volumes sold per day decreasing 25% primarily from being in ethane ejection mode. Gas processing volumes per day increased 10% and gas gathering volumes per day increased 12% between the comparative quarters due to new well connects.

Operating costs decreased $38.2 million or 49% in the third quarter of 2015 compared to the third quarter of 2014 primarily due to a 53% decrease in prices paid for natural gas purchased partially offset by a 8% increase in purchase volumes. Depreciation and amortization increased $0.7 million, or 7%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

General and administrative expenses decreased $2.5 million or 25% in the third quarter of 2015 compared to the third quarter of 2014 primarily due to lower employee costs and a $1.8 million decrease in the stock-based compensation accrual due to an evaluation of the performance based shares component of previous grants.

Loss on Disposition of Assets

There was a $7.2 million loss on disposition of assets in the third quarter of 2015 compared to a loss of $0.5 million in the third quarter of 2014. During the third quarter of 2015, we sold 30 of the drilling rigs and other drilling equipment in an auction. The proceeds from the sale of these 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.

Table of Contents

Other Income (Expense)

Interest expense, net of capitalized interest, increased $4.0 million between the comparative third quarters of 2015 and 2014 due primarily to less interest capitalized associated with unproved properties and higher average bank debt outstanding. We capitalized interest based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the third quarter of 2015 was $5.2 million compared to $8.2 million in the third quarter of 2014, and was netted against our gross interest of $13.5 million and $12.5 million for the third quarters of 2015 and 2014, respectively. Our average interest rate decreased from 6.6% to 5.3% and our average debt outstanding was $258.0 million higher in the third quarter of 2015 as compared to the third quarter of 2014 primarily due to the increase in outstanding borrowings under our credit agreement over the comparative periods.

Gain on derivatives not designated as hedges decreased $11.6 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense (benefit) changed from an expense of $41.3 million in the third quarter of 2014 to a benefit of $124.0 million in the third quarter of 2015 due to a pre-tax loss primarily from the non-cash ceiling test write-down. Our effective tax rate was 37.7% for the third quarter of 2015 compared to 37.9% for the third quarter of 2014. This decrease is primarily due to our permanent tax differences having a lesser impact on our effective tax rate due to our pre-tax loss in the third quarter of 2015. Current income tax benefit was $2.6 million for the third quarter of 2015 compared to current income tax expense of $5.5 million for the third quarter of 2014 with the decrease primarily due to decreased alternative minimum taxes anticipated for 2015 and realized in 2014. We paid $0.2 million of income taxes in the third quarter of 2015.

Table of Contents

Nine Months Ended September 30, 2015 versus Nine Months Ended September 30, 2014

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

	Nine Months Ended September 30, 2015	2014	Percent Change [1]
	(In thousands unless otherwise specified)		
Total revenue	$681,939	$1,194,393	(43)%
Net income (loss)	$(728,024)	$178,827	NM
Oil and Natural Gas:			
Revenue	$309,944	$575,176	(46)%
Operating costs excluding depreciation, depletion, amortization, and impairment	$129,871	$133,979	(3)%
Depreciation, depletion, and amortization	$202,378	$200,958	1 %
Impairment of oil and natural gas properties	$1,141,053	$—	NM
Average oil price received (Bbl)	$51.46	$92.44	(44)%
Average NGLs price received (Bbl)	$9.83	$33.05	(70)%
Average natural gas price received (Mcf)	$2.76	$3.99	(31)%
Oil production (Bbl)	2,996,000	2,801,000	7 %
NGLs production (Bbl)	3,954,000	3,376,000	17 %
Natural gas production (Mcf)	49,650,000	43,424,000	14 %
Depreciation, depletion, and amortization rate (Boe)	$12.96	$14.70	(12)%
Contract Drilling:			
Revenue	$215,114	$341,530	(37)%
Operating costs excluding depreciation and impairment	$123,717	$197,025	(37)%
Depreciation	$42,533	$61,194	(30)%
Impairment of contract drilling equipment	$8,314	$—	NM
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	37.3	73.5	(49)%
Average dayrate on daywork contracts	$19,669	$19,876	(1)%
Mid-Stream:			
Revenue	$156,881	$277,687	(44)%
Operating costs excluding depreciation and amortization	$125,081	$238,166	(47)%
Depreciation and amortization	$32,518	$29,972	8 %
Gas gathered—Mcf/day	351,619	316,658	11 %
Gas processed—Mcf/day	186,929	160,373	17 %
Gas liquids sold—gallons/day	582,760	748,805	(22)%
Corporate and other:			
General and administrative expense	$26,637	$30,409	(12)%
Gain (loss) on disposition of assets	$(6,270)	$9,092	(169)%
Other income (expense):			
Interest expense, net	$(23,482)	$(12,201)	92 %
Gain (loss) on derivatives not designated as hedges	$12,917	$(9,234)	NM

Other	$38	$3	NM
Income tax expense (benefit)	$(438,936)	$111,523	NM
Average long-term debt outstanding	$891,173	$653,521	36 %
Average interest rate	5.5 %	6.7 %	(18)%

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

41

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues decreased $265.2 million or 46% in the first nine months of 2015 as compared to the first nine months of 2014 due primarily to lower oil, natural gas, and NGLs prices partially offset by an increase in production. In the first nine months of 2015, as compared to the first nine months of 2014, oil production increased 7%, NGLs production increased 17%, and natural gas production increased 14%. Average oil prices decreased 44% to $51.46 per barrel, average natural gas prices decreased 31% to $2.76 per Mcf, and average NGLs prices decreased 70% to $9.83 per barrel.

Oil and natural gas operating costs decreased $4.1 million or 3% between the comparative first nine months of 2015 and 2014 due to lower gross production taxes due to lower sales revenue and lower general and administrative expense partially offset by higher saltwater disposal expenses and lease operating expenses.

DD&A increased $1.4 million or 1% due primarily to a 14% increase in equivalent production partially offset by a 12% decrease in the DD&A rate. The decrease in our DD&A rate in the first nine months of 2015 compared to the first nine months of 2014 resulted primarily from the effect of the ceiling test write-downs in the fourth quarter of 2014 and the first and second quarters of 2015. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

During the first nine months, we recorded three non-cash ceiling test write-downs totaling $1.1 billion pre-tax ($710.4 million, net of tax).

Contract Drilling

Drilling revenues decreased $126.4 million or 37% in the first nine months of 2015 versus the first nine months of 2014. The decrease was due primarily to a 49% decrease in the average number of drilling rigs in use partially offset by $25.7 million for fees on contracts terminated early in the first nine months of 2015. Average drilling rig utilization decreased from 73.5 drilling rigs in the first nine months of 2014 to 37.3 drilling rigs in the first nine months of 2015.

Drilling operating costs decreased $73.3 million or 37% between the comparative first nine months of 2015 and 2014. The decrease was due primarily to fewer drilling rigs operating. Contract drilling depreciation decreased $18.7 million or 30% also due primarily to fewer drilling rigs operating. In December 2014, 31 drilling rigs and other drilling equipment were written down to their estimated market value. During the second quarter of 2015, we recorded an additional impairment of approximately $8.3 million on the drilling rigs and other equipment that was sold at auction during the third quarter.

Mid-Stream

Our mid-stream revenues decreased $120.8 million or 44% in the first nine months of 2015 as compared to the first nine months of 2014 due primarily from the average price for natural gas sold decreasing 38%, the average price for NGLs sold decreasing 49%, and NGLs volumes sold per day decreasing 22% primarily from being in ethane ejection mode. Gas processing volumes per day increased 17% between the comparative periods primarily from new well connections. Gas gathering volumes per day increased 11% between the comparative periods due to new well connects.

Operating costs decreased $113.1 million or 47% in the first nine months of 2015 compared to the first nine months of 2014 primarily due to a 55% decrease in prices paid for natural gas purchased partially offset by a 15% increase in purchase volumes. Depreciation and amortization increased $2.5 million, or 8%, primarily due to capital expenditures for upgrades and well connects.

General and Administrative

General and administrative expenses decreased $3.8 million or 12% in the first nine months of 2015 compared to the first nine months of 2014 primarily due to lower employee costs and a $1.8 million decrease in the stock-based compensation accrual due to an evaluation of the performance based shares component of previous grants.

Gain (Loss) on Disposition of Assets

There was a $6.3 million loss on disposition of assets in the first nine months of 2015. This was 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, compared to a gain of

Table of Contents

$9.1 million for the sale of four idle 3,000 horsepower drilling rigs to an unaffiliated third-party in the first nine months of 2014. The proceeds from the sale of the auction 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 $11.3 million between the comparative first nine months of 2015 and 2014 due primarily to less interest capitalized associated with unproved properties and higher average bank debt outstanding. We capitalized interest based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the first nine months 2015 was $16.6 million compared to $24.5 million in the first nine months of 2014, and was netted against our gross interest of $40.1 million and $36.7 million for the first nine months of 2015 and 2014, respectively. Our average interest rate decreased from 6.7% to 5.5% and our average debt outstanding was $237.7 million higher in the first nine months of 2015 as compared to the first nine months of 2014 primarily due to the increase in outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives not designated as hedges increased $22.2 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense (benefit) changed from an expense of $111.5 million in the first nine months of 2014 to a benefit of $438.9 million in the first nine months of 2015 due to a pre-tax loss primarily from the non-cash ceiling test write-downs. Our effective tax rate was 37.6% for the first nine months of 2015 compared to 38.4% for the first nine months of 2014. This decrease is primarily due to our permanent tax differences having a lesser impact on our effective tax rate due to our pre-tax losses in the first nine months of 2015. Current income tax benefit was $1.7 million for the first nine months of 2015 compared to current income tax expense of $23.7 million for the first nine months of 2014 with the decrease primarily due to decreased anticipated alternative minimum taxes. We paid $3.3 million of income taxes in the first nine months of 2015.

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, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;

- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;

Table of Contents

- 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;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our estimates of the amounts of any ceiling test write-downs we may be required to record in future periods.

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

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in demand for and the price for commodities; 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 read that document.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, these prices have fluctuated and we expect this to continue. The prices for oil, NGLs, and natural gas also affect the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first nine months 2015 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 $526,000 per month ($6.3 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 $321,000 per month ($3.8 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 $420,000 per month ($5.0 million annualized) change in our pre-tax operating cash flow.

Table of Contents

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, 2015, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Oct’15 – Dec’15	Crude oil – swap	1,000 Bbl/day	$95.00	WTI – NYMEX
Oct’15 – Dec’15	Crude oil – collar	2,000 Bbl/day	$58.00 - $64.40	WTI – NYMEX
Oct’15 – Dec’15	Natural gas – swap	40,000 MMBtu/day	$3.98	NYMEX (HH)
Jan'16 - Dec'16	Natural gas – swap	10,000 MMBtu/day	$3.25	NYMEX (HH)
Nov'15 - Dec'16	Natural gas – three-way collar	13,500 MMBtu/day	$2.70 - $2.20 - $3.26	NYMEX (HH)

After September 30, 2015, the following non-designated hedges were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan'16 - Jun'16	Crude oil – collar	700 Bbl/day	$44.00 - $54.00	WTI – NYMEX
Jan'16 - Dec'16	Crude oil – three-way collar	700 Bbl/day	$46.50 - $35.00 - $57.00	WTI – NYMEX
Jul'16 - Dec'16	Crude oil – three-way collar [(1)]	700 Bbl/day	$47.50 - $35.00 - $63.50	WTI – NYMEX
Jan'16 - Dec'16	Natural gas – collar	27,000 MMBtu/day	$2.50 - $3.11	NYMEX (HH)

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

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 2015, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $2.4 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

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, 2015 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, 2015 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.

Table of Contents

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, 2014, 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, 2014.

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, 2015:

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid Per Share[2]	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs [1]	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2015 to July 31, 2015	—	$—	—	—
August 1, 2015 to August 31, 2015	543	19.73	543	—
September 1, 2015 to September 30, 2015	—	—	—	—

Total	543	$19.73	543	—

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

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

Table of Contents

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:

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

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, 2015

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

Date: November 3, 2015

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