UNIT CORP
Form 10-Q
May 08, 2014

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2014
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 April 25, 2014, 49,576,303 shares of the issuer's common stock were outstanding.

Table of Contents

TABLE OF CONTENTS

1

Table of Contents

Forward-Looking Statements

This report contains "forward-looking statements" – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document which addresses 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," "pre and similar expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained 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, 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 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; and
- the number of wells our oil and natural gas segment plans to drill during the year.

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. Whether actual results and developments will conform to our expectations and predictions is subject to a number of 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 that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

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

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2014	December 31, 2013
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,052	$ 18,593
Accounts receivable, net of allowance for doubtful accounts of $1,972 and $5,342 at March 31, 2014 and December 31, 2013, respectively	187,872	139,788
Materials and supplies	8,217	10,998
Current derivative asset (Note 9)	—	515
Current deferred tax asset	13,585	13,585
Assets held for sale	—	15,621
Prepaid expenses and other	12,537	12,931
Total current assets	223,263	212,031
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	4,353,248	4,235,712
Unproved properties not being amortized	557,149	545,588
Drilling equipment	1,482,902	1,477,093
Gas gathering and processing equipment	556,448	549,422
Transportation equipment	40,125	39,666
Other	95,537	87,435
	7,085,409	6,934,916
Less accumulated depreciation, depletion, amortization, and impairment	3,279,509	3,212,225
Net property and equipment	3,805,900	3,722,691
Debt issuance cost	11,447	11,844
Goodwill	62,808	62,808
Other assets	13,418	13,016
Total assets	$ 4,116,836	$ 4,022,390

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

	March 31, 2014	December 31, 2013
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 160,990	$ 154,062
Accrued liabilities (Note 4)	65,225	64,363
Income taxes payable	10,853	7,474
Current derivative liabilities (Note 9)	14,540	5,561
Current portion of other long-term liabilities (Note 5)	11,629	12,113
Total current liabilities	263,237	243,573
Long-term debt (Note 5)	645,809	645,696
Other long-term liabilities (Note 5)	145,454	158,331
Deferred income taxes	827,554	801,398
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, 49,575,959 and 49,107,004 shares issued, respectively	9,725	9,659
Capital in excess of par value	449,849	445,470
Retained earnings	1,775,208	1,718,263
Total shareholders' equity	2,234,782	2,173,392
Total liabilities and shareholders' equity	$ 4,116,836	$ 4,022,390

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 INCOME (UNAUDITED)

	Three Months Ended March 31,	
	2014	2013
	(In thousands except per share amounts)	
Revenues:		
Oil and natural gas	$188,207	$153,609
Contract drilling	106,600	107,528
Gas gathering and processing	93,181	57,395
Total revenues	387,988	318,532
Expenses:		
Oil and natural gas:		
Operating costs	40,415	43,038
Depreciation, depletion, and amortization	59,680	51,983
Contract drilling:		
Operating costs	63,804	66,002
Depreciation	18,395	17,260
Gas gathering and processing:		
Operating costs	80,960	49,410
Depreciation and amortization	9,591	7,156
General and administrative	9,637	8,673
(Gain) loss on disposition of assets	(9,426)	84
Total operating expenses	273,056	243,606
Income from operations	114,932	74,926
Other income (expense):		
Interest, net	(3,790)	(3,561)
Loss on derivatives not designated as hedges and hedge ineffectiveness, net	(18,366)	(5,924)
Other	120	(66)
Total other expense	(22,036)	(9,551)
Income before income taxes	92,896	65,375
Income tax expense:		
Current	9,795	2,517
Deferred	26,156	22,652
Total income taxes	35,951	25,169
Net income	$56,945	$40,206
Net income per common share:		
Basic	$1.17	$0.84
Diluted	$1.17	$0.83

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

Table of Contents

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Net income	$56,945	$40,206
Other comprehensive income, net of taxes:		
Change in value of derivative instruments used as cash flow hedges, net of tax of $0 and ($6,378)	—	(9,911)
Reclassification - derivative settlements, net of tax of $0 and ($1,494)	—	(2,337)
Ineffective portion of derivatives, net of tax of $0 and $526	—	823
Comprehensive income	$56,945	$28,781

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)

	Three Months Ended March 31, 2014	2013
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$56,945	$40,206
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	88,432	77,156
Loss on derivatives	18,366	2,093
Cash (payments) receipts on derivatives settled	(8,872)	4,871
Deferred tax expense	26,156	22,652
(Gain) loss on disposition of assets	(9,426)	84
Employee stock compensation plans	5,444	4,651
Other, net	1,179	1,601
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(55,175)	(7,695)
Accounts payable	(11,430)	23,332
Material and supplies	2,781	(640)
Accrued liabilities	8,666	8,937
Other, net	394	2,412
Net cash provided by operating activities	123,460	179,660
INVESTING ACTIVITIES:		
Capital expenditures	(197,266)	(192,927)
Proceeds from disposition of assets	36,748	1,456
Net cash used in investing activities	(160,518)	(191,471)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	4,000	123,300
Payments under credit agreement	(4,000)	(124,400)
Proceeds from exercise of stock options	850	72
Book overdrafts	18,667	13,018
Net cash provided by financing activities	19,517	11,990
Net increase (decrease) in cash and cash equivalents	(17,541)	179
Cash and cash equivalents, beginning of period	18,593	974
Cash and cash equivalents, end of period	$1,052	$1,153
Supplemental disclosure of cash flow information:		
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	$309	$43,332
Non-cash reductions to oil and natural gas properties related to asset retirement obligations	$(14,972)	$(12,088)
Cash paid for income taxes	$7,100	$15

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

7

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this quarterly 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, as appropriate, 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 in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 25, 2014, for the year ended December 31, 2013.

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

• Balance Sheets at March 31, 2014 and December 31, 2013;
• Statements of Income for the three months ended March 31, 2014 and 2013;
• Statements of Comprehensive Income for the three months ended March 31, 2014 and 2013; and
• Statements of Cash Flows for the three months ended March 31, 2014 and 2013.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three months ended March 31, 2014 and 2013 are not necessarily indicative of the results to be realized for the full year in the case of 2014, or that we realized for the full year of 2013.

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

With respect to the unaudited financial information for the three month periods ended March 31, 2014 and 2013, our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated May 8, 2014, which is included in this quarterly report, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the degree of 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 – DIVESTITURES

We sold non-core oil and natural gas assets, net of related expenses, for $8.7 million during the first quarter of 2014. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

During the first quarter of 2014, we sold four idle 3,000 horsepower drilling rigs to an unaffiliated third-party. These rigs were previously classified as assets held for sale at December 31, 2013. The proceeds for this sale, less costs to sell, 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.

Table of Contents

NOTE 3 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended March 31, 2014			
Basic earnings per common share	$56,945	48,493	$1.17
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	379	—
Diluted earnings per common share	$56,945	48,872	$1.17
For the three months ended March 31, 2013			
Basic earnings per common share	$40,206	48,117	$0.84
Effect of dilutive stock options, restricted stock, and SARs	—	295	(0.01)
Diluted earnings per common share	$40,206	48,412	$0.83

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

	Three Months Ended March 31,	
	2014	2013
Stock options and SARs	73,500	149,665
Average exercise price	$64.43	$58.41

NOTE 4 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2014	December 31, 2013
	(In thousands)	
Interest payable	17,260	6,504
Employee costs	15,797	27,633
Lease operating expenses	15,696	16,073
Taxes	5,432	2,313
Derivative settlements	1,370	416
Deposits on assets held for sale	—	3,750
Other	9,670	7,674
Total accrued liabilities	$65,225	$64,363

Table of Contents

NOTE 5 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

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

	March 31, 2014	December 31, 2013
	(In thousands)	
Credit agreement	$—	$—
6.625% senior subordinated notes due 2021, net of unamortized discount of $4.2 million at March 31, 2014 and $4.3 million at December 31, 2013	645,809	645,696
Total long-term debt	$645,809	$645,696

Credit Agreement. Under our Senior Credit Agreement (credit agreement), the amount available to be borrowed is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current 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. The credit agreement matures as of September 13, 2016. In connection with the amendment, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

The amount of the borrowing base–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 April 2014 redetermination, the lenders of our credit agreement approved an increase in our borrowing base to $900.0 million from $800.0 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 set forth 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 in any event 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 anytime, without a premium or penalty. At March 31, 2014, we had no outstanding borrowings under our credit agreement.

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

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 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, 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.

Table of Contents

As of March 31, 2014, we were in compliance with the covenants contained 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). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021. In total, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are guaranteed by our 100% owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on our ability to receive funds from our subsidiaries through dividends, loans, advances, or otherwise.

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

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. Before May 15, 2014, we may on any one or more occasions redeem up to 35% of the original principal amount of the Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, provided that at least 65% of the original principal amount of the Notes remains outstanding after each redemption. In addition, at any time 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. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of March 31, 2014.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2014	December 31, 2013
	(In thousands)	
Asset retirement obligation (ARO) liability	$119,900	$133,657
Workers’ compensation	19,679	20,041
Separation benefit plans	9,871	9,382
Gas balancing liability	3,775	3,775
Deferred compensation plan	3,858	3,589

	157,083	170,444
Less current portion	11,629	12,113
Total other long-term liabilities	$145,454	$158,331

Estimated annual principle payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2014 (and through 2018) are $11.6 million, $36.0 million, $5.7 million, $3.7 million, and $3.6 million, respectively.

Table of Contents

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

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

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
ARO liability, January 1:	$133,657	$146,159
Accretion of discount	1,215	1,521
Liability incurred	635	899
Liability settled	(548)	(1,519)
Liability sold	(459)	(169)
Revision of estimates [1]	(14,600)	(11,299)
ARO liability, March 31:	119,900	135,592
Less current portion	2,961	2,917
Total long-term ARO	$116,939	$132,675

(1) Plugging liability estimates were revised in both three months ended March 31, 2014 and 2013 for updates in the cost of services used to plug wells over the preceding year. We had various upward and downward adjustments.

NOTE 7 – NEW ACCOUNTING PRONOUNCEMENTS

Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The FASB has issued ASU 2014-08, the amendments in this update change the criteria for reporting discontinued operations while enhancing disclosures in this area. It also addresses sources of confusion and inconsistent application related to financial reporting of discontinued operations guidance in U.S. GAAP. Under the new guidance, only disposals representing a strategic shift that would have a major effect on the organization's operations and financial results should be presented as discontinued operations. In addition, it requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. It also requires disclosure of pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. The updates are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. Early adoption is permitted. We currently do not have any discontinued operations or disposals of components of an entity so this standard would not impact us.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. In July 2013, ASU 2013-11 was issued because GAAP does not include explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendment provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The amendments are applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. There was no effect on our financial position or results of operations when adopted.

NOTE 8 – STOCK-BASED COMPENSATION

For the three months ended March 31, 2014 and 2013, we recognized stock compensation expense for restricted stock awards of $3.8 million and $3.3 million, respectively. For the same period we also capitalized stock compensation cost for oil and natural gas properties of $0.8 million and $0.7 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.5 million and $1.3 million, respectively. The remaining unrecognized compensation cost

Table of Contents

related to unvested awards at March 31, 2014 is approximately $31.8 million of which $5.4 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is one year.

The Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (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 3,300,000 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 month periods ending March 31, 2014 and 2013. The following table shows the fair value of any restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended March 31,			
	2014		2013	
Shares granted:				
Employees	438,342		448,549	
Non employee directors	—		—	
	438,342		448,549	
Estimated fair value (in millions):				
Employees	$22.3		$21.0	
Non employee directors	—		—	
	$22.3		$21.0	
Percentage of shares granted expected to be distributed:				
Employees	95	%	94	%
Non employee directors	N/A		N/A	

The restricted stock awards granted during the first three months of 2014 and 2013 are being recognized over a three year vesting period, except for a portion of those granted to certain executive officers. As to those executive officers, 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 2017 and 2016, respectively. The actual number of performance shares that vest in 2016 and 2017 will be based on the company's achievement of 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 the performance criteria, the participants are estimated to receive the targeted amount (or approximately 100%) of the 2014 and 2013 performance based shares. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2014 awards for the first three months of 2014 was $1.0 million.

NOTE 9 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs, 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 is based, in part, on our view of current and future market conditions. As of March 31, 2014, our derivative transactions consisted of the following types of transactions:

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

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

Table of Contents

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. In August 2012, we determined–on a prospective basis–that we would no longer elect to use cash flow hedge accounting for our economic hedges. As a result, the change in fair value on all commodity derivatives entered into after that determination is reflected in the income statement and not in accumulated other comprehensive income (OCI). As of December 31, 2013, all cash flow hedges had expired.

At March 31, 2014, the following non-designated hedges were outstanding:

Term	Commodity	Volume	Weighted Average Price	Market
Apr'14 – Jun'14	Crude oil – swap	500 Bbl/day	$100.03	WTI – NYMEX
Apr'14 – Dec'14	Crude oil – swap	3,000 Bbl/day	$91.77	WTI – NYMEX
Apr'14 – Dec'14	Crude oil – collar	4,000 Bbl/day	$90.00-96.08	WTI – NYMEX
Apr'14 – Dec'14	Natural gas – swap	80,000 MMBtu/day	$4.24	IF – NYMEX (HH)
Apr'14 – Dec'14	Natural gas – collar	10,000 MMBtu/day	$3.75-4.37	IF – NYMEX (HH)

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

		Derivative Assets Fair Value	
	Balance Sheet Location	March 31, 2014	December 31, 2013
Commodity derivatives:			
Current	Current derivative asset	$—	$515
Long-term	Non-current derivative asset	—	—
Total derivative assets		$—	$515

		Derivative Liabilities Fair Value	
	Balance Sheet Location	March 31, 2014	December 31, 2013
Commodity derivatives:			
Current	Current derivative liabilities	$14,540	$5,561
Long-term	Non-current derivative liabilities	—	—
Total derivative liabilities		$14,540	$5,561

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.

We recognized in OCI the effective portion of any changes in fair value and reclassified the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions were settled. Because our cash flow hedges expired as of December 31, 2013, we had no balance in accumulated OCI at March 31, 2014. As of March 31, 2013, we had recognized a loss of $3.8 million, net of tax.

For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in loss on derivatives not designated as hedges and hedge ineffectiveness, net in our Unaudited Condensed Consolidated Statements of Income. Changes in the fair value of derivatives that were designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value that resulted from ineffectiveness was recognized in loss on derivatives not designated as hedges and hedge ineffectiveness, net.

Table of Contents

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the three months ended March 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) [1]	
	2014	2013
	(In thousands)	
Commodity derivatives	$—	$(3,838)

(1) Net of taxes.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the three months ended March 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income [1]		Amount of Gain or (Loss) Recognized in Income [2]	
		2014	2013	2014	2013
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$—	$3,831	$—	$—
Commodity derivatives	Loss on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	—	(1,349)
Total		$—	$3,831	$—	$(1,349)

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (derivatives not designated as hedging instruments) for the three months ended March 31:

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	
		2014	2013
		(In thousands)	
Commodity derivatives	Loss on derivatives not designated as hedges and hedge ineffectiveness, net [1]	$(18,366)	$(4,575)
Total		$(18,366)	$(4,575)

(1) Amount settled during the period are losses of $(8.9) million and $(5.6) million, respectively.

NOTE 10 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value. 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 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3 - generally unobservable inputs which are developed based on the best information available and may include our own internal data.

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

Table of Contents

The following tables set forth our recurring fair value measurements:

	March 31, 2014				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$—	$—	$—	$—	$—
Liabilities	(10,076)	(4,464)	(14,540)	—	(14,540)
	$(10,076)	$(4,464)	$(14,540)	$—	$(14,540)

	December 31, 2013				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$1,978	$20	$1,998	$(1,483)	$515
Liabilities	(4,429)	(2,615)	(7,044)	1,483	(5,561)
	$(2,451)	$(2,595)	$(5,046)	$—	$(5,046)

All of our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post any cash collateral with our counterparties and no collateral has been posted as of March 31, 2014.

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

Level 2 Fair Value Measurements

Commodity Derivatives. We measure the fair values of our crude oil and natural gas swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

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

The following table is a reconciliation of our level 3 fair value measurements for the three months ended March 31:

	2014	2013
	(In thousands)	
Beginning of period	$(2,595)	$(595)
Total gains or losses:		
Included in earnings [(1)]	(3,428)	(1,941)
Included in other comprehensive income (loss)	—	—
Settlements	1,559	—
End of period	$(4,464)	$(2,536)
	$(1,869)	$(1,941)

Total losses for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period

(1) Commodity collars are reported in the Unaudited Condensed Consolidated Statements of Income in oil and natural gas revenues (for cash flow hedges) and loss on derivatives not designated as hedges and hedge ineffectiveness, net, respectively.

Table of Contents

The following table provides quantitative information about our Level 3 unobservable inputs at March 31, 2014:

	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil collars	$(3,723)	Discounted cash flow	Forward commodity price curve	$0.11-$6.73
Natural gas collars	$(741)	Discounted cash flow	Forward commodity price curve	$0.00-$0.53

____

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

Based on our valuation at March 31, 2014, we determined that risk of non-performance by our counterparties was immaterial.

Fair Value of Other Financial Instruments

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

At March 31, 2014, 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 at March 31, 2014 approximates its fair value. 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 March 31, 2014 and December 31, 2013 were $645.8 million and $645.7 million, respectively. We estimated the fair value of these Notes using quoted marked prices at March 31, 2014 and December 31, 2013 which were $693.9 million and $688.2 million, respectively. These Notes would be classified as Level 2.

NOTE 11 – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Net Gains (Losses) on Cash Flow Hedges	
	2014	2013
	(In thousands)	
Balance at January 1:	$—	$7,587
Other comprehensive income before reclassification	—	(9,911)
Amounts reclassified from accumulated other comprehensive income	—	(1,514)
New current-period other comprehensive income	—	(11,425)
Balance at March 31:	$—	$(3,838)

17

Table of Contents

Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Income for the three months ended March 31 are as follows:

	2014	2013		Affected Line Item in the Statement Where Net Income is Presented
	(In thousands)			
Net gains (loss) on cash flow hedges				
Commodity derivatives	$—	$3,831		Oil and natural gas revenues
Commodity derivatives	—	(1,349	)	Loss on derivatives not designated as hedges and hedge ineffectiveness, net
	—	2,482		Total before tax
	—	(968	)	Tax expense
Total reclassification for the period	$—	$1,514		Net of tax

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 production outside the United States is not significant.

Table of Contents

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

	Three Months Ended March 31, 2014	2013
	(In thousands)	
Revenues:		
Oil and natural gas	$188,207	$153,609
Contract drilling	124,258	119,353
Elimination of inter-segment revenue	(17,658)	(11,825)
Contract drilling net of inter-segment revenue	106,600	107,528
Gas gathering and processing	120,360	80,156
Elimination of inter-segment revenue	(27,179)	(22,761)
Gas gathering and processing net of inter-segment revenue	93,181	57,395
Total revenues	$387,988	$318,532
Operating income:		
Oil and natural gas	$88,112	$58,588
Contract drilling	24,401	24,266
Gas gathering and processing	2,630	829
Total operating income (1)	115,143	83,683
General and administrative expense	(9,637)	(8,673)
Gain (loss) on disposition of assets	9,426	(84)
Loss on derivatives not designated as hedges and hedge ineffectiveness, net	(18,366)	(5,924)
Interest expense, net	(3,790)	(3,561)
Other	120	(66)
Income before income taxes	$92,896	$65,375

(1) Operating income 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 and hedge ineffectiveness, 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 Sheets of Unit Corporation and its subsidiaries as of March 31, 2014, and the related Unaudited Condensed Consolidated Statements of Income and Comprehensive Income for the three-month periods ended March 31, 2014 and 2013 and the Unaudited Condensed Consolidated Statements of Cash Flows for the three-month periods ended March 31, 2014 and 2013. These interim financial statements are the responsibility of the Company’s management.

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

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2013, and the related consolidated statements of income, shareholders’ equity, and of cash flows for the year then ended (not presented herein), and in our report dated February 25, 2014, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2013, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 8, 2014

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 contained 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 and NGLs for third parties and for our own account.

Business Outlook

Our current 2014 capital budget for all of our business segments forecasts a 33% increase over our 2013 capital budget, excluding acquisitions. Our oil and natural gas segment's capital budget is $718.0 million, a 31% increase over 2013, excluding acquisitions and ARO liability. Our drilling segment's capital budget is $132.0 million, a 105% increase over 2013. Our mid-stream segment's capital budget is $78.0 million, a 19% decrease from 2013, excluding acquisitions. New and continued projects are discussed further in the Executive Summary.

Our 2014 current capital budget is based on realized prices for the year of $90.08 per barrel of oil, $29.45 per barrel of NGLs, and $3.77 per Mcf of natural gas. This budget is subject to possible periodic adjustments for various reasons including changes in commodity prices and industry conditions. Funding for the budget will come primarily from internally generated cash flow and, if necessary, borrowings under our credit agreement.

As discussed in other parts of this report, the success of our consolidated business, as well as 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, in turn, influences the amounts we can charge for the use of those drilling rigs. Although all of our current operations are located within the United States, events outside the United States can and do have an impact on us and our industry.

In addition to their direct impact on us, low commodity prices–if sustained for a long period of time–could impact the liquidity of some of our industry partners and customers which, in turn, could limit their ability to meet their financial obligations to us.

Table of Contents

Executive Summary

Oil and Natural Gas

First quarter 2014 production from our oil and natural gas segment was 4,184,000 barrels of oil equivalent (Boe), a 6% decrease from the fourth quarter of 2013 and a 5% increase over the first quarter of 2013. The decrease from the fourth quarter of 2013 was due primarily to the impact of weather conditions, mechanical issues, and fewer days in the quarter. The increase over the first quarter of 2013 came primarily from production associated with new wells.

First quarter 2014 oil and natural gas revenues increased 8% over the fourth quarter of 2013 and increased 23% over the first quarter of 2013. The increase over the fourth quarter of 2013 was due primarily to increases in natural gas and NGLs prices. The increase over the first quarter of 2013 was due primarily to increased production as well as increases in natural gas and NGLs prices.

Our oil prices for the first quarter of 2014 decreased 3% from the fourth quarter of 2013 and decreased 4% from the first quarter of 2013, respectively. Our natural gas and NGLs prices increased 32% and 17%, respectively, over the fourth quarter of 2013 and increased 29% and 13%, respectively, over the first quarter of 2013.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 15% over the fourth quarter of 2013 and increased 34% over the first quarter of 2013. The increase over the fourth quarter of 2013 was due primarily to increased revenues from price increases and decreased gross production taxes from refunds attributable to high cost gas wells. The increase in direct profit over the first quarter of 2013 was due to increases in production and commodity prices as well as decreases in gross production taxes from refunds of $7.9 million attributable to high cost gas wells.

Operating cost per Boe produced for the first quarter of 2014 decreased 6% and 11% from the fourth quarter of 2013 and first quarter of 2013, respectively.

For 2014, we have derivative contracts for 7,250 Bbls per day of oil production and 90,000 Mmbtu per day of natural gas production. The contracts for oil production are swap contracts for 3,250 Bbls per day and collars for 4,000 Bbls per day. The swap transactions were done at a comparable average NYMEX prices of $92.35. The collar transactions were done at a comparable average NYMEX floor price of $90.00 and ceiling price of $96.08. The contracts for our natural gas production are swaps for 80,000 Mmbtu per day and a collar for 10,000 Mmbtu per day. The swap transactions were done at a comparable average NYMEX price of $4.24. The collar transaction was done at a comparable average NYMEX floor price of $3.75 and ceiling price of $4.37.

As of March 31, 2014, we completed drilling 39 wells (23.30 net wells). The combination of weather related issues and mechanical issues reduced anticipated 2014 production by approximately 2.2 billion cubic feet equivalent (Bcfe), representing approximately 2% of our original production guidance for 2014. We are revising our 2014 production guidance to approximately 18.9 to 19.2 MMBoe, an increase of 13% to 15% over 2013, although actual results continue to be subject to many factors. For 2014, we plan to participate in the drilling of 180 wells. Our oil and natural gas segment's capital budget is $718.0 million, a 31% increase over 2013, excluding acquisitions and ARO liability.

Contract Drilling

The rate at which our drilling rigs were used ("our utilization rate") for the first quarter 2014 was 57%, compared to 53% and 52% for the fourth quarter of 2013 and the first quarter of 2013, respectively.

Dayrates for the first quarter of 2014 averaged $19,615, and was essentially unchanged from both the fourth quarter of 2013 and the first quarter of 2013.

Direct profit (contract drilling revenue less contract drilling operating expense) for the first quarter of 2014 was essentially unchanged from the fourth quarter of 2013 and increased 3% over the first quarter of 2013. The increase over the first quarter of 2013 was primarily due to the increase in the number of rigs operating.

Operating cost per day for the first quarter of 2014 increased 6% over the fourth quarter of 2013 and decreased 6% from the first quarter of 2013. The increase over the fourth quarter of 2013 was due to higher per day direct costs. The decrease from the first quarter of 2013 was primarily due to lower per day direct and indirect costs and increased revenue days.

Table of Contents

Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGLs. The size of the drilling rig used in these plays will vary depending on a number of factors such as the depth to be drilled and the projected length of the horizontal part of the well. For example, operators drilling in shallower oil plays like the Mississippian play in northern Oklahoma and southern Kansas tend to use drilling rigs with lower horsepower which in turn command lower dayrates and margins. But deeper wells combined with improving technology and longer horizontal laterals require drilling rigs with higher horsepower in plays such as the Granite Wash play in western Oklahoma and the Texas panhandle. All of these factors ultimately affect the demand and mix of the type of drilling rigs used by our customers.

Currently, we have 30 term drilling contracts with original terms ranging from six months to two years. Eighteen of these contracts are up for renewal in 2014, one in the second quarter, nine in the third quarter, eight in the fourth quarter, and 12 are up for renewal in 2015. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate.

During the first quarter of 2014, four idle 3,000 horsepower drilling rigs were sold to an unaffiliated third-party. The proceeds from the sale will be used in our newly implemented drilling rig program to design and build a new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS rig. We anticipate the BOSS drilling rig will position us to more effectively meet the demands of our existing customers as well as allowing us to compete for the work of new customers.

Our anticipated 2014 capital expenditures for this segment are $132.0 million, a 105% increase over 2013. The first BOSS drilling rig began operations at the end of the first quarter of 2014, and is working initially for our oil and natural gas segment. Three additional BOSS drilling rigs are contracted to third-party operators and are being built. We anticipate they will be placed into service in the second and third quarters of 2014.

Mid-Stream

First quarter 2014 liquids sold per day increased 9% and 69% over the fourth quarter of 2013 and the first quarter of 2013, respectively. The increases in the first quarter of 2014 were due to new wells connected compared to the fourth quarter of 2013 which had reduced volumes due to ethane rejection and additional reduced volumes during the first quarter of 2013 from wells being shut in due to winter weather conditions during February of 2013. For the first quarter of 2014, gas processed per day increased 1% and 16% over the fourth quarter of 2013 and the first quarter of 2013, respectively. We upgraded several of our existing processing facilities and added processing plants which was the primary reason for increased volumes. For the first quarter of 2014, gas gathered per day decreased 3% from the fourth quarter of 2013 and increased 11% over the first quarter of 2013. The decrease from the fourth quarter of 2013 was primarily due to decreases at one of our gathering systems experiencing natural production declines associated with connected wells. The increase over the first quarter of 2013 was primarily from new wells connected.

NGLs prices in the first quarter of 2014 decreased 4% from the prices received in the fourth quarter of 2013 and decreased 6% from the prices received in the first quarter of 2013. Because certain of the 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.

Direct profit (mid-stream revenues less mid-stream operating expense) for the first quarter of 2014 were essentially unchanged from the fourth quarter of 2013 and increased 53% over the first quarter of 2013. The increase in direct profit was due primarily to increased liquid sales in the first quarter of 2014 compared to the first quarter of 2013. Total operating cost for our mid-stream segment for the first quarter of 2014 increased 13% and 64% over the fourth quarter of 2013 and the first quarter of 2013, respectively. These increases were primarily due to the cost of gas purchased.

At our Hemphill County, Texas facility, we currently have capacity to process 135 MMcf per day of our own and third-party Granite Wash natural gas production. We are continuing to connect new wells to our system as they are drilled and completed. With existing processing capacity at our Hemphill facility, we are positioned to add additional volumes with minimal capital expenditures.

Our gathering and processing facility in Reno County, Kansas consists of approximately 20 miles of gathering pipeline and two processing plants that were relocated from our Hemphill facility. The relocated equipment included a five MMcf per day refrigerated JT plant skid and a 20 MMcf per day turbo expander plant skid. Both plant skids are operational and we are continuing to connect wells to this system as they are drilled and completed. We began gathering gas at this facility during the second quarter of 2013 and processing gas in the third quarter of 2013.

Table of Contents

At our Cashion facility located in central Oklahoma, we have the capacity to process 45 MMcf per day of natural gas production. Several producers are active in this area and continue to drill new wells in the area around our system. We are connecting these new wells as they are completed. Also at this facility, with the addition of the new 25 MMcf per day processing plant, we have the ability to process additional volumes with minimal future capital expenditures.

At our Perkins facility located in central Oklahoma, we currently have 18 MMcf per day of existing processing capacity. The area surrounding our system has several producers that are actively drilling. We are connecting wells to our system as they are completed.

In the Mississippian play in north central Oklahoma, our Bellmon system consists of approximately 188 miles of pipeline, which includes a 26-mile extension to connect our existing Remington facility, a 20-mile NGL line, and two owned natural gas processing plants with total processing capacity of 90 MMcf per day. The new 60 MMcf per day processing plant became operational in the first quarter of 2014 and is available to process gas as volumes increase on this system.

In the Appalachian region, the first phase of our Pittsburgh Mills gathering system located in Allegheny County, Pennsylvania has been completed. Phase 1 of this project consists of approximately 14 miles of gathering pipeline and a related compressor station. We currently have 19 wells connected to this gathering system with plans to add wells as they are drilled. We are continuing preliminary phase 2 activities which will extend our system into Butler County, Pennsylvania. Right of way has been acquired and construction of phase 2 is expected to begin in late 2014.

Our anticipated 2014 capital expenditures for this segment are $78.0 million, a 19% decrease from 2013, excluding acquisitions.

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 the amount of 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 margins we obtain from our natural gas gathering and processing contracts.

	Three Months Ended March 31,		%
	2014	2013	Change
	(In thousands except percentages)		
Net cash provided by operating activities	$123,460	$179,660	(31)%
Net cash used in investing activities	$(160,518)	$(191,471)	(16)%
Net cash provided by financing activities	$19,517	$11,990	63%
Net increase (decrease) in cash and cash equivalents	$(17,541)	$179	

Cash Flows from Operating Activities

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

Net cash provided by operating activities in the first three months of 2014 decreased by $56.2 million from the first three months of 2013 due primarily to changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Table of Contents

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 offset inherent declines in production, which is typical in the capital-intensive oil and natural gas industry.

Cash flows used in investing activities decreased by $31.0 million for the first three months of 2014 compared to the first three months of 2013. The change was due primarily to proceeds received from the sale of four idle drilling rigs and the sale of certain non-core oil and natural gas assets offset by an increase in capital expenditures. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $7.5 million for the first three months of 2014 compared to the first three months of 2013. This was primarily due to an increase in our book overdrafts, which are checks that have been issued before the end of the period, but not presented to our bank for payment before the end of the period.

At March 31, 2014, we had unrestricted cash totaling $1.1 million and had borrowed none of the $500.0 million we had elected to then have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of March 31, 2014 and 2013 and for the three months ended March 31, 2014 and 2013:

	March 31, 2014	2013	% Change
	(In thousands except percentages)		
Working capital	$(39,974)	$(22,879)	(75)%
Long-term debt	$645,809	$715,365	(10)%
Shareholders' equity	$2,234,782	$2,010,013	11%
Ratio of long-term debt to total capitalization	22%	26%	(15)%
Net income	$56,945	$40,206	42%

Table of Contents

The following table summarizes certain operating information:

	Three Months Ended March 31, 2014	2013	% Change
Oil and Natural Gas:			
Oil production (MBbls)	810	797	2 %
Natural gas liquids production (MBbls)	1,065	804	32 %
Natural gas production (MMcf)	13,854	14,220	(3)%
Average oil price per barrel received	$91.53	$95.23	(4)%
Average oil price per barrel received excluding derivatives	$95.05	$91.94	3 %
Average NGLs price per barrel received	$39.56	$34.99	13 %
Average NGLs price per barrel received excluding derivatives	$39.56	$34.99	13 %
Average natural gas price per mcf received	$4.24	$3.30	28 %
Average natural gas price per mcf received excluding derivatives	$4.68	$3.14	49 %
Contract Drilling:			
Average number of our drilling rigs in use during the period	67.9	66.3	2 %
Total number of drilling rigs owned at the end of the period	118	127	(7)%
Average dayrate	$19,615	$19,580	— %
Mid-Stream:			
Gas gathered—Mcf/day	304,083	272,831	11 %
Gas processed—Mcf/day	150,042	129,857	16 %
Gas liquids sold—gallons/day	712,225	420,291	69 %
Number of natural gas gathering systems	38	37	3 %
Number of processing plants	14	15	(7)%

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 $40.0 million and $22.9 million as of March 31, 2014 and 2013, respectively. The effect of our derivative contracts decreased working capital by $14.5 million and $8.2 million as of March 31, 2014 and 2013, respectively.

Impact of Prices for Our Oil, NGLs, and Natural Gas

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow, and the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first three months of 2014 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would result in a corresponding $444,000 per month ($5.3 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 three months of 2014 was $4.24 compared to $3.30 for the first three months of 2013. Based on our first three months of 2014 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $264,000 per month ($3.2 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

$343,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. In the first three months of 2014, our average oil price per barrel received, including the effect of derivatives, was $91.53 compared with an average oil price, including the effect of derivatives, of $95.23 in the first three months of 2013 and our first three months of 2014 average NGLs price per barrel received, including the effect of derivatives, was $39.56 compared with an average NGLs price per barrel of $34.99 in the first three months of 2013.

Table of Contents

Because commodity prices effect the value of our oil, NGLs, and natural gas reserves, declines in those prices can result in a decline in the carrying value of our oil and natural gas properties. At March 31, 2014, the 12-month average unescalated prices were $98.46 per barrel of oil, $46.34 per barrel of NGLs, and $4.00 per Mcf of natural gas, then adjusted for price differentials. We were not required to take a write-down in the first quarter of 2014. If there are declines in the 12-month average prices, including the discounted value of our cash flow hedges, we may be required to record write-downs in future periods.

Price declines can also adversely affect the semi-annual determination 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.

Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms and gatherers under contracts with terms generally ranging anywhere from one month to five years. Our oil production is sold to independent marketing firms generally in six month increments.

Contract Drilling

Many factors influence the number of drilling rigs we are working at any given time as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Competition to keep qualified labor continues to be an issue we face in this segment. We do not believe that this shortage of qualified labor will keep us from working additional rigs, but it could cause some delays in the time needed to crew the new rigs.

Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGLs. The size of the drilling rig used in these plays will vary depending on a number of factors such as the depth to be drilled and the projected length of the horizontal part of the well. For example, operators drilling in shallower oil plays like the Mississippian play in northern Oklahoma and southern Kansas tend to use drilling rigs with lower horsepower which in turn command lower dayrates and margins. But deeper wells combined with improving technology and longer horizontal laterals require drilling rigs with higher horsepower in plays such as the Granite Wash play in western Oklahoma and the Texas panhandle. All of these factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For the first three months of 2014, our average dayrate was $19,615 per day compared to $19,580 per day for the first three months of 2013. The average number of our drilling rigs used in the first three months of 2014 was 67.9 drilling rigs (57%) compared with 66.3 drilling rigs (52%) in the first three months of 2013. Based on the average utilization of our drilling rigs during the first three months of 2014, a $100 per day change in dayrates has a $6,790 per day ($2.5 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our oil and natural gas segment. Depending on the timing of those services, some of those services are deemed to be associated with the acquisition of an ownership interest in the property. Accordingly, revenues and expenses for those drilling services are eliminated in our income statement, 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 $17.7 million and $11.8 million for the three months of 2014 and 2013, respectively, from our contract drilling segment and eliminated the associated operating expense of $12.4 million and $8.4 million during the three months of 2014 and 2013, respectively, yielding $5.3 million and $3.4 million during the three months of 2014 and 2013, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Mid-Stream Operations

Our mid-stream segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 14 processing plants, 38 gathering systems, and approximately 1,500 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. This segment enhances our ability to gather and market not only our own natural gas and NGLs but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first three months of 2014 and 2013, our mid-stream operations purchased $24.7 million and $21.0 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $2.5 million and $1.8 million, respectively. Intercompany revenue

Table of Contents

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 304,083 Mcf per day in the first three months of 2014 compared to 272,831 Mcf per day in the first three months of 2013. It processed an average of 150,042 Mcf per day in the first three months of 2014 compared to 129,857 Mcf per day in the first three months of 2013. The amount of NGLs we sold was 712,225 gallons per day in the first three months of 2014 compared to 420,291 gallons per day in the first three months of 2013. Gas gathering volumes per day in the first three months of 2014 increased 11% compared to the first three months of 2013 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes increased 16% over the comparative three months and NGLs sold increased 69% over the comparative period due primarily to new wells connected.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. Under our Senior Credit Agreement (credit agreement), the amount available to be borrowed is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current 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. The credit agreement matures as of September 13, 2016. In connection with the amendment, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. At March 31, 2014 and April 25, 2014, we did not have any borrowings under our credit agreement.

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

Lender	Participation Interest	
BOK (BOKF, NA, dba Bank of Oklahoma)	17	%
BBVA Compass Banks	17	%
Bank of Montreal	15	%
Bank of America, N.A.	15	%
Comerica Bank	8	%
Crédit Agricole Corporate and Investment Bank, London Branch	8	%
Wells Fargo Bank, National Association	8	%
Canadian Imperial Bank of Commerce	8	%
The Bank of Nova Scotia	4	%
	100	%

The amount of the borrowing base–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 April 2014 redetermination, the lenders of our credit agreement approved an increase in our borrowing base to $900.0 million from $800.0 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 set forth 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 in any event 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 anytime, without a premium or penalty.

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.

Table of Contents

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 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, 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 March 31, 2014, we were in compliance with the covenants contained 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). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021. In total, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are guaranteed by our 100% owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on our ability to receive funds from our subsidiaries through dividends, loans, advances, or otherwise.

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

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. Before May 15, 2014, we may on any one or more occasions redeem up to 35% of the original principal amount of the Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, provided that at least 65% of the original principal amount of the Notes remains outstanding after each redemption. In addition, at any time 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. 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 contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of March 31, 2014.

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. Any decision 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

Table of Contents

provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 39 gross wells (23.30 net wells) in the first three months of 2014 compared to 34 gross wells (19.72 net wells) in the first three months of 2013. Total capital expenditures for the first three months of 2014 by this segment, excluding a $15.0 million reduction in the ARO liability, totaled $159.0 million. Total capital expenditures for the first three months of 2013, excluding a $12.1 million reduction in the ARO liability, totaled $117.1 million.

Currently we plan to participate in drilling approximately 180 gross wells in 2014 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $718.0 million. Whether we are able to drill the full number of wells planned is dependent on a number of factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. During the first quarter of 2014, we sold four idle 3,000 horsepower drilling rigs to an unaffiliated third-party. The proceeds from this sale will be used in our newly implemented drilling rig program to design and build a new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS rig. We anticipate the BOSS drilling rig will position us to more effectively meet the demands of our existing customers as well as allowing us to compete for the work of new customers.

The first BOSS drilling rig began operations at the end of the first quarter of 2014, and is working initially for our oil and natural gas segment. Three additional BOSS drilling rigs are contracted to third-party operators and are being built. We anticipate they will be placed into service in the second and third quarters of 2014. Not including the three BOSS drilling rigs under construction, we currently have 118 drilling rigs in our fleet.

Our anticipated 2014 capital expenditures for this segment are $132.0 million. At March 31, 2014, we had commitments to purchase approximately $7.0 million for drilling equipment over the next twelve months. We have spent $30.1 million for capital expenditures, including $15.8 million for the BOSS drilling rigs during the first quarter of 2014 compared to $9.3 million in the first quarter of 2013.

Mid-Stream Acquisitions and Capital Expenditures. At our Hemphill County, Texas facility, we currently have capacity to process 135 MMcf per day of our own and third-party Granite Wash natural gas production. We are continuing to connect new wells to our system as they are drilled and completed. With existing processing capacity at our Hemphill facility, we are positioned to add additional volumes with minimal capital expenditures.

Our gathering and processing facility in Reno County, Kansas consists of approximately 20 miles of gathering pipeline and two processing plants that were relocated from our Hemphill facility. The relocated equipment included a five MMcf per day refrigerated JT plant skid and a 20 MMcf per day turbo expander plant skid. Both plant skids are operational and we are continuing to connect wells to this system as they are drilled and completed. We began gathering gas at this facility during the second quarter of 2013 and processing gas in the third quarter of 2013.

At our Cashion facility located in central Oklahoma, we have the capacity to process 45 MMcf per day of natural gas production. Several producers are active in this area and continue to drill new wells in the area around our system. We are connecting these new wells as they are completed. Also at this facility, with the addition of the new 25 MMcf per day processing plant, we have the ability to process additional volumes with minimal future capital expenditures.

At our Perkins facility located in central Oklahoma, we currently have 18 MMcf per day of existing processing capacity. The area surrounding our system has several producers that are actively drilling. We are connecting wells to our system as they are completed.

In the Mississippian play in north central Oklahoma, our Bellmon system consists of approximately 188 miles of pipeline, which includes a 26-mile extension to connect our existing Remington facility, a 20-mile NGL line, and two owned natural gas processing plants with total processing capacity of 90 MMcf per day. The new 60 MMcf per day processing plant became operational in the first quarter of 2014 and is available to process gas as volumes increase on this system.

In the Appalachian region, the first phase of our Pittsburgh Mills gathering system located in Allegheny County, Pennsylvania has been completed. Phase 1 of this project consists of approximately 14 miles of gathering pipeline and a related compressor station. We currently have 19 wells connected to this gathering system with plans to add wells as they are drilled. We are continuing preliminary phase 2 activities which will extend our system into Butler County, Pennsylvania. Right of way has been acquired and construction of phase 2 is expected to begin in late 2014.

Table of Contents

During the first three months of 2014, our mid-stream segment incurred $7.0 million in capital expenditures as compared to $22.4 million in the first three months of 2013. For 2014, our estimated capital expenditures are $78.0 million.

Contractual Commitments

At March 31, 2014, we had certain contractual obligations including the following:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt [1]	$1,021,281	$43,062	$86,125	$86,125	$805,969
Operating leases [2]	10,621	7,364	3,206	51	—
Drill pipe, drilling components, and equipment purchases [3]	7,014	7,014	—	—	—
Total contractual obligations	$1,038,916	$57,440	$89,331	$86,176	$805,969

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our March 31, 2014 interest rates of 6.625% for the Notes.

(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 September, 2017. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) We have committed to pay $7.0 million for drilling equipment over the next twelve months.

Table of Contents

At March 31, 2014, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan (1)	$3,858	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$9,871	$210	Unknown	Unknown	Unknown
Derivative liabilities – commodity transactions	$14,540	$14,540	$—	$—	$—
Asset retirement liability (3)	$119,900	$2,961	$39,009	$5,991	$71,939
Gas balancing liability (4)	$3,775	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability(6)	$19,679	$8,458	$2,673	$1,296	$7,252

(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. 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. There have been no repurchases in 2014 or 2013 through the first quarter.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling 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. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. All of our previous cash flow hedges expired as of December 31, 2013. Any change in fair value on all commodity derivatives we have entered into are now reflected in the income statement 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 March 31, 2014, based on our first quarter 2014 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Mark-to-Market 2014	
Daily oil production	81	%
Daily natural gas production	58	%

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

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our March 31, 2014 evaluation, we believe the risk of non-performance by our counterparties is not material. At March 31, 2014, the fair values of the net assets (liabilities) we had and the identification of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2014 (In millions)	
Bank of Montreal	$(8.6	)
The Bank of Nova Scotia	(4.8	)
Canadian Imperial Bank of Commerce	(1.1	)
Total assets (liabilities)	$(14.5	)

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At March 31, 2014, we recorded the fair value of our commodity derivatives on our balance sheet as current liabilities of $14.5 million. At March 31, 2013, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $3.2 million and current and non-current derivative liabilities of $13.8 million and $1.1 million, respectively.

For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in loss on derivatives not designated as hedges and hedge ineffectiveness, net in our Unaudited Condensed Consolidated Statements of Income. The commodity derivative instruments we had under cash flow accounting expired as of December 2013. Previous changes in the fair value of derivatives designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness was recognized in loss on derivatives not designated as hedges and hedge ineffectiveness, net. These gains (losses) at March 31 are as follows:

	2014		2013	
	(In thousands)			
Loss on derivatives not designated as hedges and hedge ineffectiveness, net:				
Loss on derivatives not designated as hedges, included are amounts settled during the period of ($8,872) and ($5,615), respectively	$(18,366	)	$(4,575	)
Gain (loss) on ineffectiveness of cash flow hedges	—		(1,349	)
	$(18,366	)	$(5,924	)

33

Table of Contents

Stock and Incentive Compensation

During the first three months of 2014, we granted awards covering 438,342 shares of restricted stock. These awards had an estimated fair value as of their grant date of $22.3 million. Compensation expense will be recognized over the three year vesting periods, and during the first three months of 2014, we recognized $0.8 million in compensation expense and capitalized $0.2 million for these awards. During the first three months of 2014, we recognized compensation expense of $3.8 million for all of our restricted stock, stock options, and SAR grants and capitalized $0.8 million of compensation cost for oil and natural gas properties.

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 $50,000 to $1.5 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 our insurance coverage will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas 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 16 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision, and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. For the first three months of 2014 and 2013, the total we received for all of these fees was $0.1 million for each period. 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

Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The FASB has issued ASU 2014-08, the amendments in this update change the criteria for reporting discontinued operations while enhancing disclosures in this area. It also addresses sources of confusion and inconsistent application related to financial reporting of discontinued operations guidance in U.S. GAAP. Under the new guidance, only disposals representing a strategic shift that would have a major effect on the organization's operations and financial results should be presented as discontinued operations. In addition, it requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. It also requires disclosure of pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. The updates are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. Early adoption is permitted. We currently do not have any discontinued operations or disposals of components of an entity so this standard would not impact us.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. In July 2013, ASU 2013-11 was issued because GAAP does not include explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendment provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The amendments are applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. There was no effect on our financial position or results of operations when adopted.

Table of Contents

Results of Operations

Quarter Ended March 31, 2014 versus Quarter Ended March 31, 2013

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

	Quarter Ended March 31,		Percent
	2014	2013	Change
Total revenue	$387,988,000	$318,532,000	22 %
Net income	$56,945,000	$40,206,000	42 %
Oil and Natural Gas:			
Revenue	$188,207,000	$153,609,000	23 %
Operating costs excluding depreciation, depletion and amortization	$40,415,000	$43,038,000	(6)%
Average oil price received (Bbl)	$91.53	$95.23	(4)%
Average NGLs price received (Bbl)	$39.56	$34.99	13 %
Average natural gas price received (Mcf)	$4.24	$3.30	28 %
Oil production (Bbl)	810,000	797,000	2 %
NGLs production (Bbl)	1,065,000	804,000	32 %
Natural gas production (Mcf)	13,854,000	14,220,000	(3)%
Depreciation, depletion and amortization rate (Boe)	$13.98	$12.90	8 %
Depreciation, depletion and amortization	$59,680,000	$51,983,000	15 %
Contract Drilling:			
Revenue	$106,600,000	$107,528,000	(1)%
Operating costs excluding depreciation	$63,804,000	$66,002,000	(3)%
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	67.9	66.3	2 %
Average dayrate on daywork contracts	$19,615	$19,580	— %
Depreciation	$18,395,000	$17,260,000	7 %
Mid-Stream:			
Revenue	$93,181,000	$57,395,000	62 %
Operating costs excluding depreciation and amortization	$80,960,000	$49,410,000	64 %
Depreciation and amortization	$9,591,000	$7,156,000	34 %
Gas gathered—Mcf/day	304,083	272,831	11 %
Gas processed—Mcf/day	150,042	129,857	16 %
Gas liquids sold—gallons/day	712,225	420,291	69 %
General and administrative expense	$9,637,000	$8,673,000	11 %
(Gain) loss on disposition of assets	$(9,426,000)	$84,000	NM
Other income (expense):			
Interest expense, net	$(3,790,000)	$(3,561,000)	6 %
Loss on derivatives not designated as hedges and hedge ineffectiveness, net	$(18,366,000)	$(5,924,000)	NM
Other	$120,000	$(66,000)	NM
Income tax expense	$35,951,000	$25,169,000	43 %
Average interest rate	6.7 %	6.3 %	6 %
Average long-term debt outstanding	$650,079,000	$719,173,000	(10)%

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

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues increased $34.6 million or 23% in the first quarter of 2014 as compared to the first quarter of 2013 due to increased production and natural gas and NGLs prices. In the first quarter of 2014, as compared to the first quarter of 2013, oil production increased 2%, NGLs production increased 32%, and natural gas production decreased 3%. Average oil prices decreased 4% to $91.53 per barrel, NGLs prices increased 13% to $39.56 per barrel, and natural gas prices increased 28% to $4.24 per Mcf.

Oil and natural gas operating costs decreased $2.6 million or 6% between the comparative first quarters of 2014 and 2013 due to lower gross production taxes from refunds of $7.9 million attributable to high cost gas wells partially offset by higher lease operating and saltwater disposal expenses along with increased general and administrative expense.

Depreciation, depletion, and amortization (“DD&A”) increased $7.7 million or 15% due primarily to an 8% increase in our DD&A rate and a 5% increase in equivalent production. The increase in our DD&A rate in the first quarter of 2014 compared to the first quarter of 2013 resulted primarily from increased capitalized cost on new wells drilled between the periods. 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.

Contract Drilling

Drilling revenues decreased $0.9 million or 1% in the first quarter of 2014 versus the first quarter of 2013. Drilling operating costs decreased $2.2 million or 3% between the comparative first quarters of 2014 and 2013. The decrease in both revenues and operating costs were primarily attributable to fewer operating days associated with third-party customers. Average drilling rig utilization increased from 66.3 drilling rigs in the first quarter of 2013 to 67.9 drilling rigs in the first quarter of 2014. Contract drilling depreciation increased $1.1 million or 7% due to increases in utilization.

Mid-Stream

Our mid-stream revenues increased $35.8 million or 62% for the first quarter of 2014 as compared to the first quarter of 2013. The average price for natural gas sold increased 40%. Gas processing volumes per day increased 16% between the comparative quarters and NGLs sold per day increased 69% between the comparative quarters. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day in the first quarter of 2013 were lower due to ethane rejection and from wells being shut in due to winter weather conditions during February of 2013. Gas gathering volumes per day increased 11% primarily from new well connections.

Operating costs increased $31.6 million or 64% in the first quarter of 2014 compared to the first quarter of 2013 primarily due to a 39% increase in prices paid for natural gas purchased and by a 13% increase in gas volumes purchased. Depreciation and amortization increased $2.4 million, or 34%, primarily due to additional assets placed into service throughout 2013 and the first quarter of 2014.

General and Administrative

General and administrative expenses increased $1.0 million or 11% in the first quarter of 2014 compared to the first quarter of 2013 primarily due to increases in the number of employees and increased employee costs.

(Gain) loss on disposition of assets

Gain on disposition of assets increased $9.5 million in the first quarter of 2014 compared to the first quarter of 2013 primarily due to the sale of four drilling rigs.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $0.2 million between the comparative first quarters of 2014 and 2013. 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 quarter of 2014 was $8.2 million compared to $8.7 million in the first quarter of 2013, and was netted against our gross interest of $12.0 million and $12.3 million for the first quarters of 2014 and 2013, respectively. Our average interest rate increased from 6.3% to

Table of Contents

6.7% and our average debt outstanding was $69.1 million lower in the first quarter of 2014 as compared to the first quarter of 2013 due to the reduction of outstanding borrowings under our credit agreement over the comparative periods.

Loss on derivatives not designated as hedges and hedge ineffectiveness increased $12.4 million over the comparative periods due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense increased $10.8 million or 43% in the first quarter of 2014 compared to the first quarter of 2013 primarily due to increased taxable income. Our effective tax rate was 38.7% for the first quarter of 2014 and 38.5% for the first quarter of 2013. Current income tax expense was $9.8 million for the first quarter of 2014 and $2.5 million for the first quarter of 2013 due to less expected depreciation. We paid approximately $7.1 million of income taxes in the first quarter of 2014.

Safe Harbor Statement

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases, and oral statements issued by or on our behalf, contain, or may contain, certain statements that are “forward-looking statements” within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events, or developments which we expect or anticipate will or may occur in the future are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” and similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, 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;
- 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; and
- the number of wells our oil and natural gas segment plans to drill during the year.

Table of Contents

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 or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

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

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

Item 3. Quantitative and Qualitative Disclosure About Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the price 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, the prices we received for our oil, NGLs, and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil, NGLs, and natural gas also affects the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first three months 2014 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would result in a corresponding $444,000 per month ($5.3 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $264,000 per month ($3.2 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 $343,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow.

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

At March 31, 2014, the following non-designated hedges were outstanding:

Term	Commodity	Volume	Weighted Average Price	Market
Apr’14 – Jun’14	Crude oil – swap	500 Bbl/day	$100.03	WTI – NYMEX
Apr’14 – Dec’14	Crude oil – swap	3,000 Bbl/day	$91.77	WTI – NYMEX
Apr’14 – Dec’14	Crude oil – collar	4,000 Bbl/day	$90.00-96.08	WTI – NYMEX

Apr’14 – Dec’14	Natural gas – swap	80,000 MMBtu/day	$4.24	IF – NYMEX (HH)
Apr’14 – Dec’14	Natural gas – collar	10,000 MMBtu/day	$3.75-4.37	IF – NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first three months of 2014, a 1% increase in the floating rate would

Table of Contents

not have a material impact on our annual pre-tax cash flow. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of March 31, 2014 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer, and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended March 31, 2014 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, as defined in Rule 13a – 15(f) under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson and Charlotte Abernathy are the Plaintiffs in this case and are royalty owners in oil and gas drilling and spacing units for which the our exploration segment distributes royalty. The Plaintiffs' central allegation is that our 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 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 Oklahoma Supreme Court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. The Plaintiffs filed a second request in 2013 to certify a class of royalty owners that is slightly smaller than their first attempt. We will continue to resist certification using the defenses described above, as well as new defenses based on the Court of Civil Appeals' decertification of the Plaintiffs' original class action. 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, 2013, 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, 2013.

39

Table of Contents

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

The following table provides information relating to our repurchase of common stock for the three months ended March 31, 2014:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2014 to January 31, 2014	—	$—	—	—
February 1, 2014 to February 28, 2014	—	—	—	—
March 1, 2014 to March 31, 2014	112,140	61.91	112,140	—
Total	112,140	$61.91	112,140	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the first quarter 2014 vesting for grants and the exercising of SARs previously made from our "Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012."

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

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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: May 8, 2014	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: May 8, 2014	By: /s/ David T. Merrill DAVID T. MERRILL Senior Vice President, Chief Financial Officer, and Treasurer