UNIT CORP
Form 10-Q
November 05, 2013
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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2013
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
[Commission File Number 1-9260]
UNIT CORPORATION
(Exact name of registrant as specified in its charter)

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

(918) 493-7700
(Registrant’s telephone number, including area code)
None
(Former name, former address and former fiscal year,
if changed since last report)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [x] No [ ]
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [x] No [ ]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [x]
As of October 25, 2013, 49,106,378 shares of the issuer's common stock were outstanding.

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Forward-Looking Statements

This quarterly report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. All statements, other than statements of historical facts, included in this quarterly 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 number of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- 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, NGLs, 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.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2013	December 31, 2012
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,741	$ 974
Accounts receivable, net of allowance for doubtful accounts of $5,342 and $5,343 at September 30, 2013 and at December 31, 2012, respectively	141,817	146,046
Materials and supplies	10,330	8,563
Current derivative asset (Note 10)	4,514	16,552
Current income tax receivable	1,389	901
Current deferred tax asset	9,371	8,765
Prepaid expenses and other	12,413	13,843
Total current assets	181,575	195,644
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	4,061,108	3,822,381
Undeveloped leasehold not being amortized	589,227	521,659
Drilling equipment	1,484,928	1,478,645
Gas gathering and processing equipment	538,258	461,629
Transportation equipment	39,286	37,728
Other	74,802	62,840
	6,787,609	6,384,882
Less accumulated depreciation, depletion, amortization, and impairment	3,133,717	2,907,660
Net property and equipment	3,653,892	3,477,222
Debt issuance cost	12,241	13,432
Goodwill	62,808	62,808
Other intangible assets, net	—	680
Non-current derivative asset (Note 10)	1,133	—
Other assets	13,046	11,334
Total assets	$ 3,924,695	$ 3,761,120

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

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

	September 30, 2013	December 31, 2012
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 132,633	$ 138,811
Accrued liabilities (Note 5)	78,557	54,098
Current portion of derivative liabilities (Note 10)	6,480	1,948
Current portion of other long-term liabilities (Note 6)	11,985	12,282
Total current liabilities	229,655	207,139
Long-term debt (Note 6)	645,584	716,359
Non-current derivative liabilities (Note 10)	938	562
Other long-term liabilities (Note 6)	158,161	166,983
Deferred income taxes	773,412	695,776
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, 49,091,928 and 48,581,948 shares issued, respectively	9,655	9,594
Capital in excess of par value	441,291	423,603
Accumulated other comprehensive income (loss) (Note 12)	(963)	7,587
Retained earnings	1,666,962	1,533,517
Total shareholders' equity	2,116,945	1,974,301
Total liabilities and shareholders' equity	$ 3,924,695	$ 3,761,120

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$157,320	$135,435	$475,728	$402,366
Contract drilling	100,647	133,420	313,180	421,198
Gas gathering and processing	75,809	52,935	203,821	159,977
Total revenues	333,776	321,790	992,729	983,541
Expenses:				
Oil and natural gas:				
Operating costs	50,139	36,147	138,171	105,035
Depreciation, depletion, and amortization	56,294	44,489	163,612	153,839
Impairment of oil and natural gas properties (Note 2)	—	—	—	115,874
Contract drilling:				
Operating costs	58,988	72,988	188,580	223,980
Depreciation	17,402	20,094	52,570	62,660
Gas gathering and processing:				
Operating costs	63,098	46,267	172,065	136,243
Depreciation and amortization	8,773	5,884	24,143	16,330
General and administrative	9,936	8,434	28,288	23,814
Gain on disposition of assets	(4,345)	(44)	(7,744)	(1,283)
Total operating expenses	260,285	234,259	759,685	836,492
Income from operations	73,491	87,531	233,044	147,049
Other income (expense):				
Interest, net	(3,625)	(7,087)	(11,777)	(11,455)
Loss on derivatives not designated as hedges and hedge ineffectiveness, net	(13,760)	(4,015)	(3,340)	(4,621)
Other	(14)	(59)	(171)	(123)
Total other income (expense)	(17,399)	(11,161)	(15,288)	(16,199)
Income before income taxes	56,092	76,370	217,756	130,850
Income tax expense:				
Current	2,111	2,516	6,745	450
Deferred	19,749	27,268	77,566	50,677
Total income taxes	21,860	29,784	84,311	51,127
Net income	$34,232	$46,586	$133,445	$79,723
Net income per common share:				
Basic	$0.71	$0.97	$2.77	$1.66
Diluted	$0.70	$0.97	$2.75	$1.66

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Net income	$34,232	$46,586	$133,445	$79,723
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of ($3,013), ($8,838), ($5,517), and $7,377	(4,797)	(14,137)	(8,617)	11,353
Reclassification - derivative settlements, net of tax of $1,240, ($5,523), $63, and ($14,793)	1,970	(8,720)	139	(23,296)
Ineffective portion of derivatives, net of tax of $97, $1,560, ($44), and $1,792	155	2,455	(72)	2,829
Comprehensive income	$31,560	$26,184	$124,895	$70,609

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

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

	Nine Months Ended September 30, 2013	2012
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$133,445	$79,723
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	242,590	234,350
Impairment of oil and natural gas properties (Note 2)	—	115,874
Loss on derivatives	1,765	4,621
Deferred tax expense	77,566	50,677
Gain on disposition of assets	(7,744)	(1,283)
Stock compensation plans	16,652	12,271
Other, net	4,263	3,376
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	1,888	4,516
Accounts payable	320	(11,753)
Material and supplies	(1,767)	(1,949)
Accrued liabilities	31,041	23,195
Other, net	942	(1,478)
Net cash provided by operating activities	500,961	512,140
INVESTING ACTIVITIES:		
Capital expenditures	(512,574)	(584,858)
Producing property and other acquisitions (Note 3)	—	(600,321)
Proceeds from disposition of assets	89,916	296,582
Net cash used in investing activities	(422,658)	(888,597)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	222,500	543,700
Payments under credit agreement	(293,600)	(593,700)
Proceeds from issuance of senior subordinated notes, net of debt issuance costs and discount	—	386,274
Proceeds from exercise of stock options	578	90
Book overdrafts	(7,014)	40,281
Net cash provided by (used in) financing activities	(77,536)	376,645
Net increase in cash and cash equivalents	767	188
Cash and cash equivalents, beginning of period	974	835
Cash and cash equivalents, end of period	$1,741	$1,023
Supplemental disclosure of cash flow information:		
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	$(516)	$26,477
Non-cash additions (reductions) to oil and natural gas properties related to asset retirement obligations	$(16,417)	$45,188

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

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this 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 quarterly report should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 26, 2013, for the year ended December 31, 2012.

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

- Balance Sheets at September 30, 2013 and December 31, 2012;
- Statements of Income for the three and nine months ended September 30, 2013 and 2012;
- Statements of Comprehensive Income for the three and nine months ended September 30, 2013 and 2012; and
- Statements of Cash Flows for the nine months ended September 30, 2013 and 2012.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the nine months ended September 30, 2013 and 2012 are not necessarily indicative of the results to be realized for the full year in the case of 2013, or that we realized for the full year of 2012.

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 and nine month periods ended September 30, 2013 and 2012, our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated November 5, 2013, 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 – OIL AND NATURAL GAS PROPERTIES

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

For the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly resulting in a non-cash ceiling test write down of $115.9 million pre-tax

($72.1 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination as of June 30, 2012, consisted of swaps

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covering 2.9 MMBoe in 2012 and 4.5 MMBoe in 2013. The effect of those hedges on the June 30, 2012 ceiling test was a $32.5 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties.

At September 30, 2013, the 12-month average commodity prices, including the discounted value of our cash flow hedges, were at levels that did not require us to take a write-down of our oil and natural gas properties. 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 a write-down in future periods.

Our qualifying cash flow hedges used in the ceiling test determination as of September 30, 2013, consisted of swaps and collars covering 1.7 MMBoe in 2013. The effect of those hedges on the September 30, 2013 ceiling test was a $2.1 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil, NGLs, and natural gas hedging is discussed in Note 10 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 3 – ACQUISITIONS AND DIVESTITURES

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble Energy, Inc. (Noble). The acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The amount paid after final closing adjustments was $592.6 million.

As of April 1, 2012, the effective date of the Noble acquisition, the estimated proved reserves of the acquired properties were 44 million barrels of oil equivalent (MMBoe). The acquisition added approximately 24,000 net acres to our Granite Wash core area in the Texas Panhandle with significant resource potential including approximately 600 horizontal drilling locations. The total acreage acquired in western Oklahoma was approximately 59,000 net acres and is characterized by high working interest and operatorship, 95% of which is held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

The Noble acquisition was accounted for using the acquisition method under ASC 805, Business Combinations, which requires that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the purchase price and the estimated values of assets acquired and liabilities assumed. It was based on information available to us at the time the unaudited condensed consolidated financial statements were prepared. We believe these estimates are reasonable; however, the estimates are subject to change as additional information becomes available and is assessed by us (in thousands):

Adjusted Purchase Price	
Total consideration given	$592,627
Adjusted Allocation of Purchase Price	
Oil and natural gas properties included in the full cost pool:	
Proved oil and natural gas properties	$260,799
Undeveloped oil and natural gas properties	353,343
Total oil and natural gas properties included in the full cost pool (1)	614,142
Equipment and facilities	25,163
Asset retirement obligation	(46,678)
Fair value of net assets acquired	$592,627

(1) We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates.

Pro Forma Financial Information

The following unaudited pro forma financial information is presented to reflect the operations of the acquired assets as if the acquisition had been completed on January 1, 2011. The unaudited pro forma financial information was derived from the historical accounting records of the seller adjusted for estimated transaction costs, depreciation, depletion and amortization, ceiling test impact, general and administrative expenses, capitalized interest, and interest on the 400.0

million of bonds issued along with additional borrowings under our credit facility to finance the acquisition. The unaudited pro forma financial

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information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of our expected future results of operations. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the acquisition or any estimated costs that will be incurred to integrate these assets. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
	(In thousands, except per share data)	
Pro forma:		
Revenues	$335,394	$1,041,350
Net income	$47,186	$140,670
Net income per common share:		
Basic	$0.98	$2.94
Diluted	$0.98	$2.92

2012 Divestitures

We completed the following divestitures in 2012, all of which were accounted for as adjustments to the full cost pool with no gain or loss recognized:

- In September 2012, we sold our interest in certain Bakken properties (located in North Dakota). The proceeds, net of related expenses, were $226.6 million.
- In September 2012, we sold certain oil and natural gas assets located in Brazos and Madison counties of Texas, for approximately $44.1 million.

2013 Divestitures

In August 2013, we sold additional Bakken property interests. The proceeds, net of related expenses, were $57.1 million. These proceeds were accounted for as adjustments to the full cost pool with no gain or loss recognized.

Other

The acquisition and divestitures completed in the third quarter 2012, were structured to allow us to secure like-kind exchange tax treatment for the transactions under Section 1031 of the Internal Revenue Code.

NOTE 4 – 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 September 30, 2013			
Basic earnings per common share	$34,232	48,254	$0.71
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	404	(0.01)
Diluted earnings per common share	$34,232	48,658	$0.70
For the three months ended September 30, 2012			
Basic earnings per common share	$46,586	47,938	$0.97
Effect of dilutive stock options, restricted stock, and SARs	—	263	—
Diluted earnings per common share	$46,586	48,201	$0.97

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The following table shows the number of stock options and SARs (and their average exercise price) not included in the prior calculation because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended September 30,	
	2013	2012
Stock options and SARs	149,665	278,901
Average exercise price	$58.41	$51.57

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2013			
Basic earnings per common share	$133,445	48,193	$2.77
Effect of dilutive stock options, restricted stock, and SARs	—	317	(0.02)
Diluted earnings per common share	$133,445	48,510	$2.75
For the nine months ended September 30, 2012			
Basic earnings per common share	$79,723	47,891	$1.66
Effect of dilutive stock options, restricted stock, and SARs	—	215	—
Diluted earnings per common share	$79,723	48,106	$1.66

The following table shows the number of stock options and SARs (and their average exercise price) not included in the prior calculation because their option exercise prices were greater than the average market price of our common stock:

	Nine Months Ended September 30,	
	2013	2012
Stock options and SARs	149,665	250,901
Average exercise price	$58.41	$52.72

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
Employee costs	$23,944	$24,632
Interest payable	17,747	6,568
Lease operating expenses	14,738	10,903
Taxes	11,563	7,308
Other	10,565	4,687
Total accrued liabilities	$78,557	$54,098

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NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES
Long-Term Debt
Our long-term debt consisted of (or arose under) the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
Credit agreement with an average interest rate of 2.9% at December 31, 2012	$—	$71,100
6.625% senior subordinated notes due 2021, net of unamortized discount of $4.4 million at September 30, 2013 and $4.7 million at December 31, 2012	645,584	645,259
Total long-term debt	$645,584	$716,359

Credit Agreement. On September 5, 2012, we amended 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 (currently $500.0 million) or the value of the borrowing base as determined by the lenders (currently $800.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. 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 credit agreement is currently scheduled to mature on September 13, 2016.

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. There was no change to the borrowing base as of the October 1, 2013 redetermination. 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 September 30, 2013, there were no outstanding borrowings under our credit agreement.

Funds under the credit agreement can be used to finance 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.

As of September 30, 2013, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million of our 6.625% Senior Subordinated Notes (the 2011 Notes). The 2011 Notes were issued at par and mature on May 15, 2021. We received net

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proceeds of approximately $244.0 million after deducting fees of approximately $6.0 million. Those fees are being amortized as debt issuance cost over the life of the 2011 Notes. We used the net proceeds to repay outstanding borrowings under our credit agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of senior subordinated notes (the 2012 Notes) due May 15, 2021. Those notes also bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance our acquisition of certain oil and natural gas properties. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On November 13, 2012, we registered with the SEC an offer on Form S-4 to exchange the 2012 Notes for additional notes with materially identical terms to our existing registered 2011 Notes. On January 7, 2013, the exchange of all the 2012 Notes was completed. The notes issued in exchange for the 2012 Notes are now registered and treated as a single series of debt securities with the 2011 Notes, bringing the total of the aggregate principal amount of 6.625% senior subordinated notes to $650.0 million (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021.

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 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 their respective Indentures described below. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on the ability of Unit to receive funds from its 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). The Indenture was supplemented by the First Supplemental Indenture dated as of May 18, 2011 and further supplemented by the Second Supplemental Indenture dated as of January 7, 2013. As supplemented, the Indenture establishes the terms and provides for the issuance of the Notes . The discussion of the Notes is qualified by and subject to the actual terms of the 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 Indenture contains customary events of default. The 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 September 30, 2013.

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Other Long-Term Liabilities

As of the dates indicated, other long-term liabilities consisted of the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
Asset retirement obligation (ARO) liability	$133,894	$146,159
Workers' compensation	20,207	18,517
Separation benefit plans	8,991	7,972
Gas balancing liability	3,838	3,838
Deferred compensation plan	3,216	2,779
	170,146	179,265
Less current portion	11,985	12,282
Total other long-term liabilities	$158,161	$166,983

Estimated annual principal payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning October 1, 2013 (and through 2018) are $12.0 million, $40.8 million, $5.2 million, $3.9 million, and $3.8 million, respectively.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

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

The following table shows certain information about our AROs:

	Nine Months Ended September 30, 2013	2012
	(In thousands)	
ARO liability, January 1:	$146,159	$96,446
Accretion of discount	4,152	3,215
Liability incurred	3,820	52,306
Liability settled	(4,071)	(1,606)
Revision of estimates [1]	(16,166)	(4,254)
ARO liability, September 30:	133,894	146,107
Less current portion	2,954	2,857
Total long-term ARO	$130,940	$143,250

(1) Plugging liability estimates were revised in both 2013 and 2012 for updates in the cost of services used to plug wells over the preceding year. We had various upward and downward adjustments as well as changes in estimated timing of cash flows.

NOTE 8 – NEW ACCOUNTING PRONOUNCEMENTS

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. Early adoption is permitted. The amendments should be applied prospectively to all unrecognized tax benefits that exist

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at the effective date. Retrospective application is permitted. We anticipate there will be no effect on our financial position or results of operations when adopted.

Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. The FASB has issued ASU 2013-10, the amendments in this update permit the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to U.S. Treasury and LIBOR. The amendments also remove the restriction on using different benchmark rates for similar hedges. The amendments are effective prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. We currently do not have any interest rate hedges at this time.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. In February 2013, the FASB issued ASU 2013-02 to address the presentation of comprehensive income related to ASU 2011-05. The standard requires that companies present, either in a single note or parenthetically on the face of the financial statements, the effect of significant amounts reclassified from each component of accumulated other comprehensive income based on its source (e.g., the release due to cash flow hedges from interest rate contracts) and the income statement line items affected by the reclassification (e.g., interest income or interest expense). The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. We chose to present the information in a single note (Note 11 of the Notes to our Unaudited Condensed Consolidated Financial Statements).

Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. In January 2013, the FASB issued ASU 2013-01 to limit the scope of balance sheet offsetting disclosures contained in previously issued guidance in ASU 2011-11—Disclosures about Offsetting Assets and Liabilities. Specifically, ASU 2011-11 applies only to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in the FASB Accounting Standards or subject to a master netting arrangement or similar agreement.

Unlike IFRS, GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. To address these differences between IFRS and GAAP, the FASB and the IASB (the Boards) issued an exposure draft that proposed new criteria for netting that were narrower than the current conditions currently in GAAP. Nevertheless, in response to feedback from their respective stakeholders, the Boards decided to retain their existing offsetting models. Instead, the Boards have issued common disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS or GAAP. The amendments in this ASU require an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. Derivatives subject to a master netting agreement are the only transactions in this accounting standard that affect us. We provide the effect of netting on our financial position in Note 11 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 9 – STOCK-BASED COMPENSATION

For the three and nine months ended September 30, 2013, we recognized stock compensation expense for restricted stock awards of $4.4 million and $12.0 million, respectively. For the same period we also capitalized stock compensation cost for oil and natural gas properties of $1.0 million and $2.6 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.8 million and $4.7 million, respectively. The remaining unrecognized compensation cost related to unvested awards at September 30, 2013 is approximately $20.7 million of which $3.3 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 of a year.

For the three and nine months ended September 30, 2012, we recognized stock compensation expense for restricted stock awards of $2.9 million and $8.2 million, respectively. For the same period we also capitalized stock compensation cost for oil and natural gas properties of $0.7 million and $2.0 million, respectively. For these same

periods, the tax benefit related to this stock based compensation was $1.2 million and $3.2 million, respectively.
We grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as to non-employee directors under our Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan). A total of 3,300,000 shares of the company's common stock is authorized for issuance to eligible participants under the amended plan. The amended plan succeeds our previous Non-employee Directors' 2000 Stock Option Plan (the option plan).

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We did not grant any SARs or stock options during either of the three or nine month periods ending September 30, 2013 and 2012. The following table shows the fair value of the restricted stock awards granted to employees and non-employee directors:

	Three Months Ended September 30,			Nine Months Ended September 30,			
	2013	2012		2013		2012	
Shares granted:							
Employees	—	2,509		448,549		370,445	
Non employee directors	—	—		21,128		24,606	
	—	2,509		469,677		395,051	
Estimated fair value (in millions):							
Employees	$—	$0.1		$21.0		$15.7	
Non employee directors	—	—		0.9		1.0	
	$—	$0.1		$21.9		$16.7	
Percentage of shares granted expected to be distributed:							
Employees	N/A	95	%	94	%	94	%
Non employee directors	N/A	—	%	100	%	100	%

The restricted stock awards granted during the three and nine months ended September 30, 2013 and 2012 are being recognized over a three year vesting period, except for a portion of those awards made to certain executive officers. As to those executive officers, 30% of the shares granted, or 57,405 shares in 2013 and 46,441 shares in 2012 (the performance shares), will cliff vest in the first half of 2016 and 2015, respectively. The actual number of performance shares that vest in 2015 and 2016 will be based on the company's achievement of certain performance criteria over a three-year period, and will range from 50% to 150% of the restricted shares granted as performance shares. Based on the performance criteria, the participants could receive more than 100% of the performance based shares. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2013 awards for the first nine months of 2013 was $7.1 million.

NOTE 10 – 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 hedged is based, in part, on our view of current and future market conditions. As of September 30, 2013, our derivative transactions consisted of the following types of hedges:

- Swaps. We receive or pay a fixed price for the hedged 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.

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. Therefore, the change in fair value on all commodity derivatives entered into after that determination will be reflected in the income statement and not in accumulated other comprehensive income (OCI).

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At September 30, 2013, we had the following outstanding cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct'13 - Dec'13	Crude oil – swap	5,500 Bbl/day	$99.71	WTI – NYMEX
Oct'13 - Dec'13	Natural gas – swap	60,000 MMBtu/day	$3.56	IF – NYMEX (HH)
Oct'13 - Dec'13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)

At September 30, 2013, we had the following outstanding non-designated hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct'13 - Dec'13	Crude oil – swap	3,000 Bbl/day	$94.59	WTI – NYMEX
Jan'14 - Dec'14	Crude oil – swap	3,000 Bbl/day	$91.77	WTI – NYMEX
Jan'14 - Jun'14	Crude oil – swap	500 Bbl/day	$100.03	WTI – NYMEX
Jan'14 - Dec'14	Crude oil – collar	4,000 Bbl/day	$90.00-96.08	WTI – NYMEX
Oct'13 - Dec'13	Natural gas – swap	20,000 MMBtu/day	$3.94	IF – NYMEX (HH)
Jan'14 - Dec'14	Natural gas – swap	50,000 MMBtu/day	$4.24	IF – NYMEX (HH)

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

	Balance Sheet Location	Derivative Assets Fair Value September 30, 2013	December 31, 2012
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative asset	$486	$13,674
Long-term	Non-current derivative asset	—	—
Total derivatives designated as hedging instruments		486	13,674
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative asset	4,028	2,878
Long-term	Non-current derivative asset	1,133	—
Total derivatives not designated as hedging instruments		5,161	2,878
Total derivative assets		$5,647	$16,552

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	Balance Sheet Location	Derivative Liabilities Fair Value September 30, 2013 (In thousands)	December 31, 2012
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative liabilities	$1,750	$1,005
Long-term	Non-current derivative liabilities	—	—
Total derivatives designated as hedging instruments		1,750	1,005
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative liabilities	4,730	943
Long-term	Non-current derivative liabilities	938	562
Total derivatives not designated as hedging instruments		5,668	1,505
Total derivative liabilities		$7,418	$2,510

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 recognize in accumulated OCI the effective portion of any changes in fair value for derivatives designated as cash flow hedges and reclassify the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions are settled. As of September 30, 2013 and 2012, we had recognized a loss of $1.0 million and a gain of $9.9 million, net of tax, respectively, in accumulated OCI.

Based on market prices at September 30, 2013, we expect to transfer over the next three months (in the related month of settlement) a loss of approximately $1.0 million, net of tax, into revenue. The cash flow derivative instruments existing as of September 30, 2013 are expected to mature by December 2013.

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 gain (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 designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. When the hedged item is recognized into earnings, it is reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness is recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net. Before October 2012, we reported all gains (losses) associated with derivatives in oil and natural gas revenues. We reflect gains (losses) on non-designated hedges and ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation.

This table shows the effect of derivative instruments on our Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the nine months ended September 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) [(1)] 2013 (In thousands)	2012
Commodity derivatives	$ (963)	$ 9,912

(1) Net of taxes.

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This table shows the effect of derivative instruments on our Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the three months ended September 30:

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]	
		2013	2012	2013	2012
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$(3,210)	$14,243	$—	$—
Commodity derivatives	Loss on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	(252)	(4,015)
Total		$(3,210)	$14,243	$(252)	$(4,015)

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

This table shows the effect of derivative instruments on our Unaudited Condensed Consolidated Statements of Income (derivatives not designated as hedging instruments) for the three months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative [1]	
		2013	2012
		(In thousands)	
Commodity derivatives	Loss on derivatives not designated as hedges and hedge ineffectiveness, net	$(13,508)	$—
Total		$(13,508)	$—

(1) Amount settled during the period is a loss of ($2.434) and $0, respectively.

This table shows the effect of derivative instruments on our Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the nine months ended September 30:

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]	
		2013	2012	2013	2012
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$(202)	$38,088	$—	$—
Commodity derivatives	Loss on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	116	(4,621)
Total		$(202)	$38,088	$116	$(4,621)

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

This table shows the effect of derivative instruments on our Unaudited Condensed Consolidated Statements of Income (derivatives not designated as hedging instruments) for the nine months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative [1]	
		2013	2012
		(In thousands)	
Commodity derivatives	Loss on derivatives not designated as hedges and hedge ineffectiveness, net	$(3,456)	$—
Total		$(3,456)	$—

(1) Amount settled during the period is a loss of ($1.575) and $0, respectively.

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NOTE 11 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value. 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.

The following tables set forth our recurring fair value measurements:

	September 30, 2013				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$8,473	$—	$8,473	$(2,826)	$5,647
Liabilities	(7,622)	(2,622)	(10,244)	2,826	(7,418)
	$851	$(2,622)	$(1,771)	$—	$(1,771)

	December 31, 2012				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$18,555	$—	$18,555	$(2,003)	$16,552
Liabilities	(3,918)	(595)	(4,513)	2,003	(2,510)
	$14,637	$(595)	$14,042	$—	$14,042

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 September 30, 2013.

Certain natural gas fixed price swaps were transferred from Level 3 to Level 2 as of June 30, 2012 because of improvements in our ability to obtain and corroborate observable significant inputs to assess the fair value. Our policy is to recognize transfers either in or out of fair value hierarchy levels as of the end of the quarterly reporting period in which the event or change in circumstances causing the transfer occurred.

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.

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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 tables are reconciliations of our level 3 fair value measurements:

	Commodity Collars			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Beginning of period	$1,446	$8,130	$(595)	$33,615
Total gains or losses:				
Included in earnings [(1)]	(3,949)	2,241	(2,544)	19,114
Included in other comprehensive income (loss)	(119)	(4,194)	(119)	(7,770)
Settlements	—	(4,574)	636	(21,432)
Transfers out of Level 3 into Level 2	—	—	—	(21,924)
End of period	$(2,622)	$1,603	$(2,622)	$1,603
Total losses for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	$(3,949)	$(2,333)	$(1,908)	$(2,318)

(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.

The following table provides quantitative information about our Level 3 unobservable inputs at September 30, 2013:

Commodity [(1)]	Fair Value	Valuation Technique	Unobservable Input	Range
	(In thousands)			
Oil collars	$(2,503)	Discounted cash flow	Forward commodity price curve	($7.79) - $6.86
Natural gas collar	$(119)	Discounted cash flow	Forward commodity price curve	($0.19) - $0.03

(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 paid or received within the settlement period.

Based on our valuation at September 30, 2013, 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 September 30, 2013, 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 September 30, 2013 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 September 30, 2013 and December 31, 2012 were $645.6 million and

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$645.3 million, respectively. We estimated the fair value of these Notes using quoted market prices at September 30, 2013 and December 31, 2012 which were $666.3 million and $687.7 million, respectively. These Notes would be classified as Level 2.

NOTE 12 – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Net Gains (Losses) on Cash Flow Hedges	
	2013	2012
	(In thousands)	
Balance at July 1:	$1,709	$30,314
Other comprehensive income (loss) before reclassification	(4,797)	(14,137)
Amounts reclassified from accumulated other comprehensive income (loss)	2,125	(6,265)
New current-period other comprehensive income (loss)	(2,672)	(20,402)
Balance at September 30:	$(963)	$9,912

Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Income for the three months ended September 30 are as follows:

	2013	2012	Affected Line Item in the Statement Where Net Income is Presented
	(In thousands)		
Net gains (loss) on cash flow hedges			
Commodity derivatives	$(3,210)	$14,243	Oil and natural gas revenues
Commodity derivatives	(252)	(4,015)	Loss on derivatives not designated as hedges and hedge ineffectiveness, net
	(3,462)	10,228	Total before tax
	1,337	(3,963)	Tax expense (benefit)
Total reclassification for the period	$(2,125)	$6,265	Net of tax

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

	Net Gains (Losses) on Cash Flow Hedges	
	2013	2012
	(In thousands)	
Balance at January 1:	$7,587	$19,026
Other comprehensive income (loss) before reclassification	(8,617)	11,353
Amounts reclassified from accumulated other comprehensive income (loss)	67	(20,467)
New current-period other comprehensive income (loss)	(8,550)	(9,114)
Balance at September 30:	$(963)	$9,912

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Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Income for the nine months ended September 30 are as follows:

	2013	2012	Affected Line Item in the Statement Where Net Income is Presented
	(In thousands)		
Net gains (loss) on cash flow hedges			
Commodity derivatives	$(202)	$38,088	Oil and natural gas revenues
Commodity derivatives	116	(4,621)	Loss on derivatives not designated as hedges and hedge ineffectiveness, net
	(86)	33,467	Total before tax
	19	(13,000)	Tax expense (benefit)
Total reclassification for the period	$(67)	$20,467	Net of tax

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NOTE 13 – INDUSTRY SEGMENT INFORMATION

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

- 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 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 production in Canada is not significant.

The following table provides certain information about each segment's operations:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(In thousands)			
Revenues:				
Oil and natural gas	$157,320	$135,435	$475,728	$402,366
Contract drilling	119,105	145,561	357,118	458,945
Elimination of inter-segment revenue	(18,458)	(12,141)	(43,938)	(37,747)
Contract drilling net of inter-segment revenue	100,647	133,420	313,180	421,198
Gas gathering and processing	99,007	70,394	272,073	210,550
Elimination of inter-segment revenue	(23,198)	(17,459)	(68,252)	(50,573)
Gas gathering and processing net of inter-segment revenue	75,809	52,935	203,821	159,977
Total revenues	$333,776	$321,790	$992,729	$983,541
Operating income:				
Oil and natural gas	$50,887	$54,799	$173,945	$27,618 (2)
Contract drilling	24,257	40,338	72,030	134,558
Gas gathering and processing	3,938	784	7,613	7,404
Total operating income (1)	79,082	95,921	253,588	169,580
General and administrative	(9,936)	(8,434)	(28,288)	(23,814)
Gain on disposition of assets	4,345	44	7,744	1,283
Loss on derivatives not designated as hedges and hedge ineffectiveness, net	(13,760)	(4,015)	(3,340)	(4,621)
Interest expense, net	(3,625)	(7,087)	(11,777)	(11,455)
Other	(14)	(59)	(171)	(123)
Income before income taxes	$56,092	$76,370	$217,756	$130,850

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

(2) In June 2012, we had a non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax).

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NOTE 14 – SUBSEQUENT EVENT

In October 2013, five of our idle drilling rigs met the criteria for classification as assets held for sale. One drilling rig was sold in October and the other four drilling rigs are under contract to be sold with closings anticipated to occur during the fourth quarter of 2013 and the first quarter of 2014. The drilling rigs are being sold to two separate unaffiliated third-parties. The proceeds for the sale of these assets, less costs to sell, is expected to exceed the approximate $17.2 million net book value of the drilling rigs, both in the aggregate and for each drilling rig.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying Unaudited Condensed Consolidated Balance Sheets of Unit Corporation and its subsidiaries as of September 30, 2013, and the related Unaudited Condensed Consolidated Statements of Income and Comprehensive Income for the three and nine-month periods ended September 30, 2013 and 2012 and the Unaudited Condensed Consolidated Statements of Cash Flows for the nine-month periods ended September 30, 2013 and 2012. 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, 2012, 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 26, 2013, 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, 2012, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
November 5, 2013

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

Management's Discussion and Analysis (MD&A) provides an understanding of our operating results and financial condition by focusing on changes in certain key measures during the periods discussed. 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 as well as 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 for third parties and for our own account.

Business Outlook

As discussed in other parts of this quarterly 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 our natural gas, NGLs, and oil 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 (with the exception of a minor amount of production in Canada) 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.

Executive Summary

Oil and Natural Gas Segment

Third quarter 2013 production was 4,217,000 barrels of oil equivalent (Boe), a 3% increase over the second quarter of 2013 and a 21% increase over the third quarter of 2012. These increases came primarily from new wells completed in oil and NGLs rich prospects that were brought online and from production associated with 2012 acquisitions.

Third quarter 2013 revenues decreased 5% from the second quarter of 2013 and increased 16% over the third quarter of 2012. The decrease from the second quarter of 2013 was due primarily to decreases in oil production coupled with decreases in natural gas and NGLs prices somewhat offset by increases in natural gas and NGLs production coupled with higher oil prices. The increase over the third quarter of 2012 was due primarily to increased natural gas and NGLs production along with higher oil and NGLs prices.

Our oil prices for the third quarter of 2013 increased 1% over the second quarter of 2013 and increased 5% over the third quarter of 2012. Our NGLs prices decreased 7% from the second quarter of 2013 and increased 32% over the third quarter of 2012. Our natural gas prices decreased 15% and 9% from the second quarter of 2013 and third quarter of 2012, respectively.

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Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 11% from the second quarter of 2013 and increased 8% over the third quarter of 2012. The decrease from the second quarter of 2013 is due to lower oil production, lower natural gas and NGLs prices, and higher operating costs due primarily to salt water disposal and well servicing costs. The increase over the third quarter of 2012 is due primarily to increases in natural gas and NGLs production and increases in oil and NGLs prices.

Operating cost per Boe produced for the third quarter of 2013 increased 9% over the second quarter of 2013 and increased 15% over the third quarter of 2012. Costs were higher between the third and second quarter of 2013 primarily due to higher salt water disposal costs. Costs were higher between the third quarter of 2013 and the third quarter of 2012 due to costs from additional wells acquired under acquisitions and wells completed during 2013.

For 2013, approximately 8,330 barrels per day of this segment's oil production and approximately 100,000 Mmbtu per day of its natural gas production is currently hedged. The oil production is hedged under swap contracts at an average price of $97.94 per barrel. The natural gas production is hedged by swaps for 80,000 Mmbtu per day and a collar for 20,000 Mmbtu per day. The swap transactions were executed at a comparable average NYMEX price of $3.65. The collar transaction was executed at a comparable average NYMEX floor price of $3.25 and ceiling price of $3.72.

For 2014, 7,248 barrels per day of oil production and 50,000 Mmbtu per day of natural gas production is currently hedged. The oil production is hedged by swaps for 3,248 barrels per day and collars for 4,000 barrels per day. The swap transactions were executed at an average price of $92.35 per barrel. The collar transactions were executed at an average floor price of $90.00 per barrel and ceiling price of $96.08 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $4.24.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble. The acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The final closing adjusted amount paid was $592.6 million.

Also in September 2012, we sold our interests in certain Bakken properties. The proceeds, net of related expenses, were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas for approximately $44.1 million. In August 2013, we sold additional Bakken property interests. The proceeds, net of related expenses, were $57.1 million. All three dispositions were accounted for as adjustments to the full cost pool with no gain or loss recognized.

As of September 30, 2013, we had completed drilling 102 wells (56.79 net wells). For all of 2013, we plan to participate in the drilling of approximately 170 wells. Our oil and natural gas segment’s estimated capital expenditures are $580.0 million, excluding acquisitions and ARO liability. Our 2013 production guidance is approximately 16.4 to 16.9 MMBoe, an increase of 15% to 19% over 2012, although actual results will continue to be subject to many factors.

Contract Drilling Segment

The rate at which our drilling rigs were used (“our utilization rate”) remained unchanged at 51% for the third quarter of 2013 compared to the second quarter of 2013 and decreased from 58% compared to the third quarter of 2012.

Dayrates for the third quarter of 2013 averaged $19,773, an increase of 1% over the second quarter of 2013 and a 1% decrease from the third quarter of 2012. The decrease was due primarily to the termination of certain contracts during 2012 that had higher rates (drilling rigs that were under long-term contracts, but were terminated early by the operator).

Direct profit (contract drilling revenue less contract drilling operating expense) for the third quarter of 2013 increased 1% over the second quarter of 2013 and decreased 31% from the third quarter of 2012. The decrease from the third quarter of 2012 was due primarily to 13% fewer drilling rigs operating and 14% lower per day revenue. The third quarter of 2012 included $6.7 million in revenue for early termination fees on three drilling rigs that were under long-term contracts but were terminated early by the operator compared to $0.9 million for the termination of one long-term drilling contract in 2013.

Operating cost per day for the third quarter of 2013 decreased 6% from the second quarter of 2013 and decreased 8% from the third quarter of 2012. The decrease from the second quarter of 2013 was primarily due to decreases in indirect costs and worker's compensation expense. The decrease from the third quarter of 2012 was due to lower indirect costs.

With the weakening of natural gas prices over the last several years the demand for drilling rigs in our contract drilling segment shifted to drilling wells focused on oil and NGL production. Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGLs. Part of this shift included operators moving to shallower oil plays like the Mississippian play in northern Oklahoma and southern Kansas. These shallower plays tend to use drilling rigs with lower horsepower which have lower dayrates and margins. As methods for drilling horizontal wells have improved, demand to drill deeper and longer horizontal wells are starting to once again strengthen demand for higher horsepower rigs. All of these factors ultimately affect the demand and mix of the type of drilling rigs used by our customers.

As of September 30, 2013, we had 23 term drilling contracts with original terms ranging from six months to three years. Six of these contracts are up for renewal in the fourth quarter of 2013. Term contracts may contain a fixed rate for the length of the contract or provide for periodic rate adjustments during the term.

During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. We also placed a new 1,500 horsepower, diesel-electric drilling rig into service working under a three year contract in Wyoming. Additionally, during the second quarter of 2012, we placed another new 1,500 horsepower, diesel-electric drilling rig in North Dakota (also under a three year contract). During the third quarter of 2012, one of our drilling rigs was damaged by a fire. The net book value of the damaged rig equipment was $3.2 million. We expect that all of the net book value of the damaged equipment will be recoverable from insurance proceeds. No personnel were injured in this incident.

In the second quarter of 2013, we sold a 2,000 horsepower electric drilling rig and during the third quarter of 2013, we sold two additional 2,000 horsepower electric drilling rigs. Subsequent to September 30, 2013, we sold another 2,000 horsepower electric drilling rig. All of these sales were to unaffiliated third-parties. Four additional idle 3,000 horsepower drilling rigs are under contract to be sold with closings anticipated to occur during the fourth quarter of 2013 and the first quarter of 2014. The proceeds from these sales will be used in our new drilling rig program, a program we launched to design and build a new proprietary drilling rig, the BOSS rig. We anticipate this drilling rig will position us to more effectively meet the demands of our existing customer as well as allowing us to compete for the work of new customers.

Our estimated 2013 capital expenditures for this segment are $59.0 million. Our plans for the year include continuing to refurbish and upgrade several of our existing drilling rigs in order that those drilling rigs can be used in horizontal drilling operations. Currently, we are in the process of constructing our first BOSS rig, a new prototype 1,500 horsepower AC electric drilling rig. This new drilling rig is expected to be operational in the fourth quarter of 2013, and will operate initially for our oil and natural gas segment. Our second BOSS drilling rig is committed to an operator in North Dakota and is planned to go into service in the second quarter of 2014. We are optimistic that the BOSS drilling rig will continue to be well received by operators and will result in additional new-build contract opportunities.

Mid-Stream Segment

Third quarter 2013 liquids sold per day increased 15% over the second quarter of 2013 and increased 2% over the third quarter of 2012. For the third quarter of 2013, gas processed per day increased 5% over the second quarter of 2013 and increased 8% over the third quarter of 2012. These increases are primarily due to connecting new wells to both existing and newly constructed systems. For the third quarter of 2013, gas gathered per day was essentially unchanged from the second quarter of 2013 and increased 35% over the third quarter of 2012. The increase over the third quarter of 2012 was primarily from new well connects.

NGLs prices in the third quarter of 2013 increased 10% over the prices received in the second quarter of 2013 and increased 30% over the prices received in the third quarter of 2012. 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 third quarter of 2013 increased 15% over the second quarter of 2013 and increased 91% over the third quarter of 2012. The increase over the second quarter of 2013 is due to higher liquids sold volumes and higher liquids sold prices somewhat offset by lower gas sold revenues and higher cost of gas purchased. The increase over the third quarter of 2012 is due to increased revenues due to gas liquids sold and gas sold primarily due to increased prices somewhat offset by higher cost of gas purchased.

Total operating cost for our mid-stream segment for the third quarter of 2013 increased 6% over the second quarter of 2013 and increased 36% over the third quarter of 2012 due mainly to the cost of gas purchased.

After relocating two processing plants to our new Reno County, Kansas facility, our Hemphill County, Texas facility has the capacity to process 135 MMcf per day of our own and third party Granite Wash natural gas production. We are in the process of completing two pipeline extension projects for a total cost of approximately $5.7 million. These extensions will connect additional production from our oil and natural gas segment to this system.

We have completed initial construction of our new gathering system and processing facility in Reno County, Kansas. This new system consists of approximately 20 miles of gathering pipeline and the two processing plants relocated from our Hemphill facility, a five MMcf per day refrigeration plant and a 20 MMcf per day turbo expander plant. We began gathering gas at this facility during the second quarter and processing gas in the third quarter of 2013.

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At our Cashion facility located in central Oklahoma, we completed the extension of our gathering system approximately three miles at a capital cost of $2.8 million. This extension will allow us to gather additional production from active producers in the area.

In the Mississippian play in north central Oklahoma, our Bellmon system consists of approximately 142 miles of pipeline, which includes a 26 mile extension to connect our existing Remington plant, a 20 mile NGL line and two natural gas processing plants. In the first quarter of 2013, we completed the installation of the second processing plant, a 30 MMcf per day cryogenic plant. This second plant is currently processing approximately 30 MMcf per day from third party producers in the area. Due to increasing volumes, we are in the process of installing an additional 60 MMcf per day processing plant. This new cryogenic processing plant is expected to be operational in the fourth quarter of 2013.

Our estimated 2013 capital expenditures for this segment are $96.0 million, 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 as well as the proceeds from our Notes. 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.

The following is a summary of certain financial information as of September 30, 2013 and 2012 and for each of the nine months then ended:

	September 30, 2013	2012	% Change
	(In thousands except percentages)		
Working capital	$(48,080)	$(37,363)	(29)%
Long-term debt	$645,584	$645,154	—%
Shareholders' equity	$2,116,945	$2,028,976	4%
Ratio of long-term debt to total capitalization	23%	24%	(4)%
Net income	$133,445	$79,723	67%
Net cash provided by operating activities	$500,961	$512,140	(2)%
Net cash used in investing activities	$(422,658)	$(888,597)	(52)%
Net cash provided by (used in) financing activities	$(77,536)	$376,645	(121)%

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The following table summarizes certain operating information:

	Nine Months Ended September 30, 2013	2012	% Change
Oil and Natural Gas:			
Oil production (MBbls)	2,470	2,367	4 %
Natural gas liquids production (MBbls)	2,758	2,014	37 %
Natural gas production (MMcf)	42,411	34,403	23 %
Average oil price per barrel received	$95.20	$92.96	2 %
Average oil price per barrel received excluding hedges	$95.49	$91.93	4 %
Average NGLs price per barrel received	$30.87	$30.70	1 %
Average NGLs price per barrel received excluding hedges	$30.87	$29.61	4 %
Average natural gas price per mcf received	$3.35	$3.26	3 %
Average natural gas price per mcf received excluding hedges	$3.38	$2.29	48 %
Contract Drilling:			
Average number of our drilling rigs in use during the period	65.0	77.2	(16)%
Total number of drilling rigs owned at the end of the period	124	127	(2)%
Average dayrate	$19,651	$19,982	(2)%
Mid-Stream:			
Gas gathered—Mcf/day	308,645	240,318	28 %
Gas processed—Mcf/day	137,725	134,799	2 %
Gas liquids sold—gallons/day	505,584	576,358	(12)%
Number of natural gas gathering systems	39	40	(3)%
Number of processing plants	15	13	15 %

At September 30, 2013, we had unrestricted cash totaling $1.7 million and had borrowed none of the $500.0 million we had elected to have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

On May 18, 2011, we completed the registered sale of $250.0 million aggregate principal amount of 6.625% Senior Subordinated Notes (the 2011 Notes) due 2021. The 2011 Notes were issued at par and mature on May 15, 2021. The net proceeds were used to repay outstanding borrowings under our credit agreement, which had $220.3 million outstanding as of May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of senior subordinated notes (the 2012 Notes) due May 15, 2021, bearing interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance our acquisition of certain oil and natural gas properties. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On November 13, 2012, we registered an offer with the SEC on Form S-4 to exchange the 2012 Notes for additional notes with materially identical terms to our existing registered 2011 Notes. On January 7, 2013, the exchange of the 2012 Notes was completed. The notes issued in exchange for all the 2012 Notes are now registered and are treated as a single series of debt securities with the 2011 Notes, resulting in a total of $650.0 million aggregate principal amount of 6.625% senior subordinated notes (the Notes). The interest of the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021.

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 hedging activity. We had negative working capital of $48.1 million and $37.4 million, respectively, as of September 30, 2013 and 2012. The effect of our hedging activity decreased working capital by $1.4 million as of September 30, 2013 and increased working capital by $8.3 million as of September 30, 2012.

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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. 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 nine months of 2013 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $450,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of hedging, during the first nine months of 2013 was $3.35 compared to $3.26 for the first nine months of 2012. Based on our first nine months of 2013 production, a $1.00 per barrel change in our oil price, without the effect of hedging, 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 hedging, would have a $292,000 per month ($3.5 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2013, our average oil price per barrel received, including the effect of hedging, was $95.20 compared with an average oil price, including the effect of hedging, of $92.96 in the first nine months of 2012 and our first nine months of 2013 average NGLs price per barrel received, including the effect of hedging, was $30.87 compared with an average NGLs price per barrel of $30.70 in the first nine months of 2012.

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 September 30, 2013, the 12-month average unescalated prices were $95.08 per barrel of oil, $38.98 per barrel of NGLs, and $3.61 per Mcf of natural gas, then adjusted for price differentials. We were not required to take a write-down in the third quarter of 2013. 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.

In the second quarter of 2012, the unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGLs, and natural gas reserves. As a result, we recorded a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). At September 30, 2012, the 12-month average unescalated prices were $94.97 per barrel of oil, $48.85 per barrel of NGLs, and $2.83 per Mcf of natural gas, adjusted for price differentials.

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. With the weakening of natural gas prices over the last several years the demand for drilling rigs in our contract drilling segment shifted to drilling wells focused on oil and NGL production. Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGLs. Part of this shift included operators moving to shallower oil plays like the Mississippian play in northern Oklahoma and southern Kansas. These shallower plays tend to use drilling rigs with lower horsepower which have lower dayrates and margins. As methods for drilling horizontal wells have improved, demand to drill deeper and longer horizontal wells are starting to once again strengthen demand for higher horsepower rigs. All of these factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. For the first nine months of 2013, our average dayrate was $19,651 per day compared to $19,982 per day for the first nine months of 2012. The average number of our drilling rigs used in the first nine months of 2013 was 65.0 drilling rigs (51%) compared with

77.2 drilling rigs (61%) in the first nine months of 2012. Based on the average utilization of our drilling rigs during the first nine months of 2013, a $100 per day change in dayrates has a $6,500 per day ($2.4 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

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recognized as a reduction in our investment in our oil and natural gas properties. The drilling contracts used for these services are issued under the same conditions and rates as the drilling contracts entered into with unrelated third parties. We eliminated revenue of $43.9 million and $37.7 million for the nine months of 2013 and 2012, respectively, from our contract drilling segment and eliminated the associated operating expense of $32.2 million and $24.8 million during the nine months of 2013 and 2012, respectively, yielding $11.7 million and $12.9 million during the nine months of 2013 and 2012, 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, 15 processing plants, 39 gathering systems, and approximately 1,435 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 nine months of 2013 and 2012, this segment purchased $62.6 million and $47.5 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $5.7 million and $3.0 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 308,645 Mcf per day in the first nine months of 2013 compared to 240,318 Mcf per day in the first nine months of 2012. It processed an average of 137,725 Mcf per day in the first nine months of 2013 compared to 134,799 Mcf per day in the first nine months of 2012. The amount of NGLs sold was 505,584 gallons per day in the first nine months of 2013 compared to 576,358 gallons per day in the first nine months of 2012. Gas gathering volumes per day in the first nine months of 2013 increased 28% compared to the first nine months of 2012 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes increased 2% from the comparative nine months and NGLs sold decreased 12% from the comparative period due primarily to one of our customers completing construction of their own processing plant and moving their volumes off our system during the second half of 2012, resulting in decreases from the nine months ended 2012.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On September 5, 2012, we amended 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 (currently $500.0 million) or the value of the borrowing base as determined by the lenders (currently $800.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. 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 credit agreement is currently scheduled to mature on September 13, 2016. At October 25, 2013 and September 30, 2013, there were no borrowings.

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. There was no change to the borrowing base as of the October 1, 2013 redetermination. We or the lenders may request a onetime special

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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.

Funds under the credit agreement can be used to finance 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.

As of September 30, 2013, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million of our 6.625% Senior Subordinated Notes due 2021 (the 2011 Notes). The 2011 Notes were issued at par and mature on May 15, 2021. We received net proceeds of approximately $244.0 million after deducting fees of approximately $6.0 million. Those fees are being amortized as debt issuance cost over the life of the 2011 Notes. We used the net proceeds to repay outstanding borrowings under our credit agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of senior subordinated notes (the 2012 Notes) due May 15, 2021. Those notes also bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance our acquisition of certain oil and natural gas properties. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On November 13, 2012, we registered with the SEC an offer on Form S-4 to exchange the 2012 Notes for additional notes with materially identical terms to our existing registered 2011 Notes. On January 7, 2013, the exchange of all the 2012 Notes was completed. The notes issued in exchange for the 2012 Notes are now registered and treated as a single series of debt securities with the 2011 Notes, bringing the total of the aggregate principal amount of 6.625% senior subordinated notes to $650.0 million (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021.

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 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 their respective Indentures described below. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on the ability of Unit to receive funds from its 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). The Indenture was supplemented by the

First Supplemental Indenture dated as of May 18, 2011 and further supplemented by the Second Supplemental Indenture dated as of January 7,

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2013. As supplemented, the Indenture establishes the terms and provides for the issuance of the Notes . The discussion of the Notes is qualified by and subject to the actual terms of the 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 Indenture contains customary events of default. The 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 September 30, 2013.

Segment Dispositions, Acquisitions, and Capital Expenditures

Oil and Natural Gas Segment. Most 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 drilling) depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 102 gross wells (56.79 net wells) in the first nine months of 2013 compared to 129 gross wells (58.02 net wells) in the first nine months of 2012. Total capital expenditures for oil and gas properties on the full cost method for the first nine months of 2013 by this segment, excluding a $16.4 million reduction in the ARO liability, totaled $387.1 million. Total capital expenditures for the first nine months of 2012, excluding a $45.2 million net increase ARO liability and $575.4 million for acquisitions, totaled $384.2 million.

For all of 2013, we plan to participate in the drilling of approximately 170 wells and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $580.0 million. Whether we 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.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble. The acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The final closing adjusted amount paid was $592.6 million.

Also in September 2012, we sold our interest in certain Bakken properties. The proceeds, net of related expenses, were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas for approximately $44.1 million. In August 2013, we sold additional Bakken property interests. The proceeds, net of related expenses, were $57.1 million. All three dispositions were accounted for as adjustments to the full cost pool with no gain or loss recognized.

Contract Drilling Segment. During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. We also placed a new 1,500 horsepower, diesel-electric drilling rig into service working under a three year contract in Wyoming. Additionally, during the second quarter of 2012, we placed another new 1,500 horsepower, diesel-electric drilling rig in North Dakota (also under a three year contract). During the third quarter of 2012, one of our drilling rigs was damaged by a fire. The net book value of the damaged rig equipment was $3.2 million. We expect that all of the net book value of the damaged equipment will be recoverable from insurance proceeds. No personnel were injured in this incident.

In the second quarter of 2013, we sold a 2,000 horsepower electric drilling rig and during the third quarter of 2013, we sold two additional 2,000 horsepower electric drilling rigs. Subsequent to September 30, 2013, we sold another 2,000 horsepower electric drilling rig. All of these sales were to unaffiliated third-parties. Four additional idle 3,000 horsepower drilling rigs are under contract to be sold with closings anticipated to occur during the fourth quarter of 2013 and the first quarter of 2014. The proceeds from these sales will be used in our new drilling rig program, a program we launched to design and build a new proprietary drilling rig, the BOSS rig. We anticipate this drilling rig will position us to more effectively meet the demands of our existing customer as well as allowing us to compete for the work of new customers. We currently have 123 drilling rigs in our fleet.

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Our estimated 2013 capital expenditures for this segment are $59.0 million. At September 30, 2013, we had commitments to purchase approximately $3.2 million of drilling equipment over the next twelve months. During the first nine months of 2013, we have spent $37.4 million for capital expenditures as compared to $62.9 million in the first nine months of 2012. Currently, we are in the process of constructing our first BOSS rig, a new prototype 1,500 horsepower AC electric drilling rig. This new drilling rig is expected to be operational in the fourth quarter of 2013, and will operate initially for our oil and natural gas segment. Our second BOSS drilling rig is committed to an operator in North Dakota and is planned to go into service in the second quarter of 2014. We are optimistic that the BOSS drilling rig will continue to be well received by operators and will result in additional new-build contract opportunities.

Mid-Stream Segment. After relocating two processing plants to our new Reno County, Kansas facility, our Hemphill County, Texas facility has the capacity to process 135 MMcf per day of our own and third party Granite Wash natural gas production. We are in the process of completing two pipeline extension projects for a total cost of approximately $5.7 million. These extensions will connect additional production from our oil and natural gas segment to this system. We have completed initial construction of our new gathering system and processing facility in Reno County, Kansas. This new system consists of approximately 20 miles of gathering pipeline and the two processing plants relocated from our Hemphill facility, a five MMcf per day refrigeration plant and a 20 MMcf per day turbo expander plant. We began gathering gas at this facility during the second quarter and processing gas in the third quarter of 2013.

At our Cashion facility located in central Oklahoma, we completed the extension of our gathering system approximately three miles at a capital cost of $2.8 million. This extension will allow us to gather additional production from active producers in the area.

In the Mississippian play in north central Oklahoma, our Bellmon system consists of approximately 142 miles of pipeline, which includes a 26 mile extension to connect our existing Remington plant, a 20 mile NGL line and two natural gas processing plants. In the first quarter of 2013, we completed the installation of the second processing plant, a 30 MMcf per day cryogenic plant. This second plant is currently processing approximately 30 MMcf per day from third party producers in the area. Due to increasing volumes, we are in the process of installing an additional 60 MMcf per day processing plant. This new cryogenic processing plant is expected to be operational in the fourth quarter of 2013.

During the first nine months of 2013, our mid-stream segment incurred $76.6 million in capital expenditures as compared to $120.3 million in the first nine months of 2012. For 2013, our estimated capital expenditures (excluding acquisitions) are $96.0 million. At September 30, 2013, we had a remaining commitment of $3.4 million for a processing plant to be completed within the next twelve months.

Contractual Commitments

At September 30, 2013, 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	$43,063	$86,125	$86,125	$805,968
Operating leases [2]	12,887	8,479	4,224	184	—
Drill pipe, drilling components, and equipment purchases [3]	6,590	6,590	—	—	—
Total contractual obligations	$1,040,758	$58,132	$90,349	$86,309	$805,968

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our September 30, 2013 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 $3.2 million for drilling equipment and $3.4 million for a processing plant over the next twelve months.

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At September 30, 2013, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan [1]	$3,216	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [2]	$8,991	$408	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$7,418	$6,480	$938	$—	$—
Asset retirement liability [3]	$133,894	$2,954	$43,402	$6,511	$81,027
Gas balancing liability [4]	$3,838	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [5]	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability[6]	$20,207	$8,623	$2,595	$1,203	$7,786

(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. We made repurchases of $16,000 and $56,000 in 2013 and 2012, respectively through the first nine months.

(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 hedge transactions that may cover part of the interest rate payable under our credit agreement or the prices we will receive 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. Therefore, the change in fair value, on all commodity derivatives entered into after that determination, will be reflected in the income statement and not in accumulated other comprehensive income. We currently do no have any interest rate hedge transactions outstanding.

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Commodity Hedges. Our hedging of our oil, NGLs, and natural gas production is 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 hedge(s) is based, in part, on our view of current and future market conditions. At September 30, 2013, based on our third quarter 2013 average daily production, the approximated percentages of our production that we have hedged are as follows:

	Hedge Designation			
	Cash Flow	Mark-to-Market	Total	Mark-to-Market
	2013	2013	2013	2014
Daily oil production	62 %	32 %	94 %	82 %
Daily natural gas production	51 %	13 %	64 %	32 %

With respect to the commodities subject to our hedges, the use of hedging limits the risk of adverse downward price movements. However, these hedges also limit our ability to realize possible future revenues that would otherwise result from price movements above the hedged prices.

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our September 30, 2013 evaluation, we believe the risk of non-performance by our counterparties is not material. At September 30, 2013, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	September 30, 2013
	(In millions)
The Bank of Nova Scotia	$4.5
Canadian Imperial Bank of Commerce	0.6
Comerica Bank	0.5
Bank of America	(0.4)
Bank of Montreal	(7.0)
Total assets (liabilities)	$(1.8)

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At September 30, 2013, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current assets of $4.5 million and $1.1 million, respectively and current and non-current derivative liabilities of $6.5 million and $0.9 million. At September 30, 2012, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $14.5 million and $1.9 million, respectively, and non-current derivative liabilities of $1.2 million.

We recognize in accumulated other comprehensive income the effective portion of any changes in fair value on our cash flow hedges and reclassify the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions are settled. As of September 30, 2013, we had recognized a loss of $1.0 million, net of tax, from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at September 30, 2013, we expect to transfer to earnings a loss of approximately $1.0 million, net of tax, included in accumulated OCI during the next three months in the related month of production. The commodity derivative instruments under cash flow accounting existing as of September 30, 2013 are expected to mature by December 2013.

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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 gain (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 designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. When the hedged item is recognized into earnings, it is reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness is recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net. Before October 2012, we reported all gains (losses) associated with derivatives in oil and natural gas revenues. We reflect gains (losses) on non-designated hedges and ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation. These gains (losses) at September 30 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net:				
Losses on derivatives not designated as hedges, included are amounts settled during the period of ($2,434), $0, ($1,575), and $0, respectively	$(13,508)	$—	$(3,456)	$—
Gains (losses) on ineffectiveness of cash flow hedges	(252)	(4,015)	116	(4,621)
	$(13,760)	$(4,015)	$(3,340)	$(4,621)

Stock and Incentive Compensation

During the first nine months of 2013, we granted awards covering 469,677 shares of restricted stock. These awards had an estimated fair value as of their grant date of $21.9 million. Compensation expense will be recognized over the three year vesting periods, and during the nine months of 2013, we recognized $5.8 million in compensation expense and capitalized $1.3 million for these awards. During the first nine months of 2013, we recognized compensation expense of $12.0 million for all of our restricted stock grants and capitalized $2.6 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $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 nine months of 2013 and 2012, the total we received for all of these fees was $0.4 million and

$0.7 million, respectively. Our proportionate share of assets, liabilities, and net income (loss) relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

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

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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. Early adoption is permitted. The amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. We anticipate there will be no effect on our financial position or results of operations when adopted.

Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. The FASB has issued ASU 2013-10, the amendments in this update permit the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to U.S. Treasury and LIBOR. The amendments also remove the restriction on using different benchmark rates for similar hedges. The amendments are effective prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. We currently do not have any interest rate hedges at this time.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. In February 2013, the FASB issued ASU 2013-02 to address the presentation of comprehensive income related to ASU 2011-05. The standard requires that companies present, either in a single note or parenthetically on the face of the financial statements, the effect of significant amounts reclassified from each component of accumulated other comprehensive income based on its source (e.g., the release due to cash flow hedges from interest rate contracts) and the income statement line items affected by the reclassification (e.g., interest income or interest expense). The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. We chose to present the information in a single note (Note 11 of the Notes to our Unaudited Condensed Consolidated Financial Statements).

Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. In January 2013, the FASB issued ASU 2013-01 to limit the scope of balance sheet offsetting disclosures contained in previously issued guidance in ASU 2011-11—Disclosures about Offsetting Assets and Liabilities. Specifically, ASU 2011-11 applies only to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in the FASB Accounting Standards or subject to a master netting arrangement or similar agreement.

Unlike IFRS, GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. To address these differences between IFRS and GAAP, the FASB and the IASB (the Boards) issued an exposure draft that proposed new criteria for netting that were narrower than the current conditions currently in GAAP. Nevertheless, in response to feedback from their respective stakeholders, the Boards decided to retain their existing offsetting models. Instead, the Boards have issued common disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS or GAAP. The amendments in this ASU require an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. Derivatives subject to a master netting agreement are the only transactions in this accounting standard that affect us. We provide the effect of netting on our financial position in Note 11 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

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Results of Operations

Quarter Ended September 30, 2013 versus Quarter Ended September 30, 2012

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

	Quarter Ended September 30, 2013	2012	Percent Change [1]
Total revenue	$333,776,000	$321,790,000	4 %
Net income	$34,232,000	$46,586,000	(27)%
Oil and Natural Gas:			
Revenue	$157,320,000	$135,435,000	16 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$50,139,000	$36,147,000	39 %
Average oil price (Bbl)	$95.49	$91.07	5 %
Average NGLs price (Bbl)	$28.10	$21.34	32 %
Average natural gas price (Mcf)	$3.11	$3.40	(9)%
Oil production (Bbl)	814,000	861,000	(5)%
NGLs production (Bbl)	1,019,000	684,000	49 %
Natural gas production (Mcf)	14,304,000	11,716,000	22 %
Depreciation, depletion and amortization rate (Boe)	$13.14	$12.54	5 %
Depreciation, depletion and amortization	$56,294,000	$44,489,000	27 %
Contract Drilling:			
Revenue	$100,647,000	$133,420,000	(25)%
Operating costs excluding depreciation	$58,988,000	$72,988,000	(19)%
Percentage of revenue from daywork contracts	100 %	100 %	—
Average number of drilling rigs in use	63.5	73.4	(13)%
Average dayrate on daywork contracts	$19,773	$19,989	(1)%
Depreciation	$17,402,000	$20,094,000	(13)%
Mid-Stream:			
Revenue	$75,809,000	$52,935,000	43 %
Operating costs excluding depreciation and amortization	$63,098,000	$46,267,000	36 %
Depreciation and amortization	$8,773,000	$5,884,000	49 %
Gas gathered—Mcf/day	326,474	241,271	35 %
Gas processed—Mcf/day	145,020	134,907	8 %
Gas liquids sold—gallons/day	586,446	576,889	2 %
General and administrative expense	$9,936,000	$8,434,000	18 %
Gain on disposition of assets	$(4,345,000)	$(44,000)	NM
Other income (expense): [2]			
Interest expense, net	$(3,625,000)	$(7,087,000)	(49)%
Loss on derivatives not designated as hedges and hedge ineffectiveness	$(13,760,000)	$(4,015,000)	NM
Other	$(14,000)	$(59,000)	(76)%
Income tax expense	$21,860,000	$29,784,000	(27)%
Average interest rate	6.5 %	6.0 %	8 %
Average long-term debt outstanding	$672,938,000	$666,375,000	1 %

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

(2) During the third quarter of 2012, we made the decision to prospectively use mark-to-market accounting for our economic hedges. Previously, we reported all designated and non-designated hedging gains (losses) in oil and natural gas revenues. We now reflect gains (losses) on non-designated hedges and the ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year

amounts have been reclassified to conform to current year presentation.

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Oil and Natural Gas

Oil and natural gas revenues increased $21.9 million or 16% in the third quarter of 2013 as compared to the third quarter of 2012 due to a 21% increase in equivalent production primarily from production associated with 2012 acquisitions and new wells completed in oil and NGLs rich prospects that were brought online. In the third quarter of 2013, as compared to the third quarter of 2012, oil production decreased 5%, NGLs production increased 49%, and natural gas production increased 22%. Average oil prices increased 5% to $95.49 per barrel, NGLs prices increased 32% to $28.10 per barrel, and natural gas prices decreased 9% to $3.11 per Mcf.

Oil and natural gas operating costs increased $14.0 million or 39% between the comparative third quarters of 2013 and 2012 due to higher salt water disposal costs, gross production taxes, and increased general and administrative expense from both higher cost per equivalent barrel produced and increases due to owning more wells.

Depreciation, depletion, and amortization (“DD&A”) increased $11.8 million, or 27% between comparative quarters due primarily to a 5% increase in our DD&A rate and by a 21% increase in equivalent production. The increase in our DD&A rate in the third quarter of 2013 compared to the third quarter of 2012 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 $32.8 million or 25% in the third quarter of 2013 versus the third quarter of 2012. The decrease was due primarily to a 13% decrease in the average number of drilling rigs in use as well as a 1% decrease in the average dayrate in the third quarter of 2013 compared to the third quarter of 2012. Average drilling rig utilization decreased from 73.4 drilling rigs in the third quarter of 2012 to 63.5 drilling rigs in the third quarter of 2013. During the third quarter of 2012, we had three drilling rigs that were under long-term contracts that were terminated early by the operator. The early termination fees associated with these contracts included in revenue was approximately $6.7 million compared to $0.9 million for the termination of one long-term drilling contract in 2013.

Drilling operating costs decreased $14.0 million or 19% between the comparative third quarters of 2013 and 2012. The decrease was due primarily to operating fewer rigs. Contract drilling depreciation decreased $2.7 million or 13% also due primarily to the decrease in utilization.

Mid-Stream

Our mid-stream revenues increased $22.9 million or 43% in the third quarter of 2013 as compared to the third quarter of 2012. The average price for natural gas sold increased 36% and the average price for NGLs sold increased 30%. Gas processing volumes per day increased 8% between the comparative quarters and NGLs sold per day increased 2% between the comparative quarters due to connecting new wells to our existing and newly constructed systems. Gas gathering volumes per day increased 35% primarily from new well connections.

Operating costs increased $16.8 million or 36% in the third quarter of 2013 compared to the third quarter of 2012 primarily due to a 30% increase in prices paid for natural gas purchased and a 6% increase in the per day gas volumes purchased. Depreciation and amortization increased $2.9 million, or 49%, primarily due to additional assets placed into service throughout 2012 and the first nine months of 2013.

General and Administrative

General and administrative expenses increased $1.5 million or 18% in the third quarter of 2013 compared to the third quarter of 2012 primarily due to increases in the number of employees and increased employee costs.

Gain on Disposition of Assets

Gain on disposition of assets increased $4.3 million in the third quarter of 2013 compared to the third quarter of 2012 primarily due to the sale of two drilling rigs.

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Other Income (Expense)

Interest expense, net of capitalized interest, decreased $3.5 million, or 49% between the comparative third quarters of 2013 and 2012. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Our average interest rate increased from 6.0% to 6.5% and our average debt outstanding was $6.6 million higher in the third quarter of 2013 as compared to the third quarter of 2012 causing our gross interest expense to be higher offset by higher capitalized interest due to the higher interest rates and higher undeveloped cost resulting in a net decrease in interest expense.

Loss on derivatives not designated as hedges and hedge ineffectiveness, net increased $9.7 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense decreased $7.9 million, or 27% in the third quarter of 2013 compared to the third quarter of 2012. Our effective tax rate was 39.0% for both the third quarter of 2013 and 2012. Current income tax expense was $2.1 million for the third quarter of 2013 compared to $2.5 million for the second quarter of 2012. We paid $0.2 million of income taxes in the third quarter of 2013.

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Nine Months Ended September 30, 2013 versus Nine Months Ended September 30, 2012

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

	Nine Months Ended September 30,		Percent
	2013	2012	Change [1]
Total revenue	$992,729,000	$983,541,000	1 %
Net income	$133,445,000	$79,723,000	67 %
Oil and Natural Gas:			
Revenue	$475,728,000	$402,366,000	18 %
Operating costs excluding depreciation, depletion, amortization and impairment	$138,171,000	$105,035,000	32 %
Average oil price (Bbl)	$95.20	$92.96	2 %
Average NGLs price (Bbl)	$30.87	$30.70	1 %
Average natural gas price (Mcf)	$3.35	$3.26	3 %
Oil production (Bbl)	2,470,000	2,367,000	4 %
NGLs production (Bbl)	2,758,000	2,014,000	37 %
Natural gas production (Mcf)	42,411,000	34,403,000	23 %
Depreciation, depletion and amortization rate (Boe)	$13.08	$15.06	(13)%
Depreciation, depletion and amortization	$163,612,000	$153,839,000	6 %
Impairment of oil and natural gas properties	$—	$115,874,000	(100)%
Contract Drilling:			
Revenue	$313,180,000	$421,198,000	(26)%
Operating costs excluding depreciation	$188,580,000	$223,980,000	(16)%
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	65.0	77.2	(16)%
Average dayrate on daywork contracts	$19,651	$19,982	(2)%
Depreciation	$52,570,000	$62,660,000	(16)%
Mid-Stream:			
Revenue	$203,821,000	$159,977,000	27 %
Operating costs excluding depreciation and amortization	$172,065,000	$136,243,000	26 %
Depreciation and amortization	$24,143,000	$16,330,000	48 %
Gas gathered—Mcf/day	308,645	240,318	28 %
Gas processed—Mcf/day	137,725	134,799	2 %
Gas liquids sold—gallons/day	505,584	576,358	(12)%
General and administrative expense	$28,288,000	$23,814,000	19 %
Gain on disposition of assets	$7,744,000	$1,283,000	NM
Other income (expense): [2]			
Interest expense, net	$(11,777,000)	$(11,455,000)	3 %
Loss on derivatives not designated as hedges and hedge ineffectiveness	$(3,340,000)	$(4,621,000)	(28)%
Other	$(171,000)	$(123,000)	39 %
Income tax expense	$84,311,000	$51,127,000	65 %
Average interest rate	6.3 %	5.9 %	7 %
Average long-term debt outstanding	$703,771,000	$433,544,000	62 %

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

(2) During the third quarter of 2012, we made the decision to prospectively use mark-to-market accounting for our economic hedges. Previously, we reported all designated and non-designated hedging gains (losses) in oil and natural gas revenues. We now reflect gains (losses) on non-designated hedges and the ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year

amounts have been reclassified to conform to current year presentation.

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Oil and Natural Gas

Oil and natural gas revenues increased $73.4 million or 18% in the first nine months of 2013 as compared to the first nine months of 2012 due to a 22% increase in equivalent production primarily from production associated with 2012 acquisitions and new wells completed in oil and NGLs rich prospects that were brought online. In the first nine months of 2013, as compared to the first nine months of 2012, oil production increased 4%, NGLs production increased 37%, and natural gas production increased 23%. Average oil prices increased 2% to $95.20 per barrel, NGLs prices increased 1% to $30.87 per barrel, and natural gas prices increased 3% to $3.35 per Mcf.

Oil and natural gas operating costs increased $33.1 million or 32% between the comparative first nine months of 2013 and 2012 due primarily to higher salt water disposal costs due to more wells owned and increased general and administrative expense.

DD&A increased $9.8 million, or 6% between the comparative periods due primarily to a 22% increase in equivalent production partially offset by a 13% decrease in our DD&A rate. The decrease in our DD&A rate in the first nine months of 2013 compared to the first nine months of 2012 resulted primarily from a reduction to the full cost pool from the non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax) that occurred during the second quarter of 2012 and the non-cash ceiling test write-down of $167.7 million pre-tax ($104.4 million, net of tax) that occurred during the fourth quarter of 2012. 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 $108.0 million or 26% in the first nine months of 2013 versus the first nine months of 2012. The decrease was due primarily to a 16% decrease in the average number of drilling rigs in use and a 2% decrease in the average dayrate in the first nine months of 2013 compared to the first nine months of 2012. Average drilling rig utilization decreased from 77.2 drilling rigs in the first nine months of 2012 to 65.0 drilling rigs in the first nine months of 2013. During the first nine months of 2012, we had seven drilling rigs that were under contracts that were terminated early by the operator. The early termination fees associated with these contracts included in revenues was approximately $22.5 million compared to $0.9 million for the termination of one long-term drilling contract in 2013.

Drilling operating costs decreased $35.4 million or 16% between the comparative first nine months of 2013 and 2012. The decrease was due primarily to operating fewer rigs. Contract drilling depreciation decreased $10.1 million or 16% also due primarily to the decrease in utilization.

Mid-Stream

Our mid-stream revenues increased $43.8 million or 27% for the first nine months of 2013 as compared to the first nine months of 2012. The average price for natural gas sold increased 51%. Gas processing volumes per day increased 2% between the comparative periods and NGLs sold per day decreased 12% between the comparative periods. NGLs sold volumes per day decreased due primarily to one of our customers completing construction of their own processing plant and moving their volumes off our system during the second half of 2012. Gas gathering volumes per day increased 28% primarily from new well connections.

Operating costs increased $35.8 million or 26% in the first nine months of 2013 compared to the first nine months of 2012 primarily due to a 27% increase in prices paid for natural gas purchased. Depreciation and amortization increased $7.8 million, or 48%, primarily due to additional assets placed into service throughout 2012 and the first nine months of 2013.

General and Administrative

General and administrative expenses increased $4.5 million or 19% in the first nine months of 2013 compared to the first nine months of 2012 primarily due to increases in the number of employees and increased employee costs.

Gain on Disposition of Assets

Gain on disposition of assets increased $6.5 million in the first nine months of 2013 compared to the first nine months of 2012 primarily due to the sale of three drilling rigs.

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Other Income (Expense)

Interest expense, net of capitalized interest, increased $0.3 million between the comparative first nine months of 2013 and 2012. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Our average interest rate increased from 5.9% to 6.3% and our average debt outstanding was $270.2 million higher in the first nine months of 2013 as compared to the first nine months of 2012 primarily due to the issuance of $400.0 million of senior subordinated notes during the third quarter of 2012 to partially fund the Noble Energy, Inc. acquisition.

Loss on derivatives not designated as hedges and hedge ineffectiveness, net decreased $1.3 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense increased $33.2 million or 65% in the first nine months of 2013 compared to the first nine months of 2012 primarily due to increased income. Our effective tax rate was 38.7% for the first nine months of 2013 and 39.1% for the first nine months of 2012. Current income tax expense was $6.7 million for the first nine months of 2013 compared to $0.5 million for the first nine months of 2012. We paid $7.3 million of income taxes in the first nine months of 2013.

Safe Harbor Statement

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

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- 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.

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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 nine months 2013 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $450,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $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 hedging, would have a $292,000 per month ($3.5 million annualized) change in our pre-tax operating cash flow.

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

At September 30, 2013, we had the following outstanding cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct'13 - Dec'13	Crude oil – swap	5,500 Bbl/day	$99.71	WTI – NYMEX
Oct'13 - Dec'13	Natural gas – swap	60,000 MMBtu/day	$3.56	IF – NYMEX (HH)
Oct'13 - Dec'13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)

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At September 30, 2013, we had the following outstanding non-designated hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct'13 - Dec'13	Crude oil – swap	3,000 Bbl/day	$94.59	WTI – NYMEX
Jan'14 - Dec'14	Crude oil – swap	3,000 Bbl/day	$91.77	WTI – NYMEX
Jan'14 - Jun'14	Crude oil – swap	500 Bbl/day	$100.03	WTI – NYMEX
Jan'14 - Dec'14	Crude oil – collar	4,000 Bbl/day	$90.00-96.08	WTI – NYMEX
Oct'13 - Dec'13	Natural gas – swap	20,000 MMBtu/day	$3.94	IF – NYMEX (HH)
Jan'14 - Dec'14	Natural gas – swap	50,000 MMBtu/day	$4.24	IF – NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election, bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first nine months of 2013, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $0.5 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of September 30, 2013 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer, and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended September 30, 2013 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 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 recently filed a second request 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.

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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, 2012, 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.

Except as set forth below, 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, 2012.

Potential listing of species as "endangered" under the federal Endangered Species Act could result in increased costs and new operating restrictions or delays on our operations and that of our customers, which could adversely affect our operations and financial results.

The federal Endangered Species Act, referred to as the "ESA," and analogous state laws regulate a variety of activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas. All three of our business segments could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future undertake operations. For instance, the American Burying Beatle and the Lesser Prairie-Chicken both have habitat in areas where we operate or provide services. The FWS initiated the process to list the Lesser Prairie-Chicken as threatened in November 2012. The sage grouse and certain wildflower species, among others, are also species that have been or are being considered for protected status under the ESA and whose range can coincide with oil and natural gas production activities. The presence of protected species in areas where we provide contract drilling or mid-stream services or conduct exploration and production operations could impair our ability to timely complete or carry out those services and, consequently, adversely affect our results of operations and financial position.

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

The following table provides information relating to our repurchase of common stock for the three months ended September 30, 2013:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2013 to July 31, 2013	261	$45.93	261	—
August 1, 2013 to August 31, 2013	20,526	46.49	20,526	—
September 1, 2013 to September 30, 2013	—	—	—	—
Total	20,787	$46.48	20,787	—

(1)

The shares were repurchased to remit withholding of taxes on the value of stock distributed with the third quarter 2013 vesting for grants 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.

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Item 3. Defaults Upon Senior Securities
Not applicable.
Item 4. Mine Safety Disclosures
Not applicable.
Item 5. Other Information
Not applicable.
Item 6. Exhibits
Exhibits:

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

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SIGNATURES

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

	Unit Corporation
Date: November 5, 2013	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: November 5, 2013	By: /s/ David T. Merrill DAVID T. MERRILL Senior Vice President, Chief Financial Officer, and Treasurer