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 June 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 July 25, 2013, 49,105,339 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 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 that could cause our actual results to differ materially from our expectations, including:

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

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2013	December 31, 2012
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,041	$ 974
Accounts receivable, net of allowance for doubtful accounts of $5,342 and $5,343 at June 30, 2013 and at December 31, 2012, respectively	156,706	146,046
Materials and supplies	9,314	8,563
Current derivative asset (Note 9)	9,895	16,552
Current income tax receivable	3,348	901
Current deferred tax asset	8,980	8,765
Prepaid expenses and other	10,385	13,843
Total current assets	199,669	195,644
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	4,015,975	3,822,381
Undeveloped leasehold not being amortized	543,535	521,659
Drilling equipment	1,487,769	1,478,645
Gas gathering and processing equipment	511,896	461,629
Transportation equipment	39,076	37,728
Other	70,065	62,840
	6,668,316	6,384,882
Less accumulated depreciation, depletion, amortization, and impairment	3,061,990	2,907,660
Net property and equipment	3,606,326	3,477,222
Debt issuance cost	12,638	13,432
Goodwill	62,808	62,808
Other intangible assets, net	171	680
Non-current derivative asset (Note 9)	4,887	—
Other assets	13,025	11,334
Total assets	$ 3,899,524	$ 3,761,120

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

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

	June 30, 2013	December 31, 2012
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 118,084	$ 138,811
Accrued liabilities (Note 4)	58,832	54,098
Current portion of derivative liabilities (Note 9)	879	1,948
Current portion of other long-term liabilities (Note 5)	12,136	12,282
Total current liabilities	189,931	207,139
Long-term debt (Note 5)	715,474	716,359
Non-current derivative liabilities (Note 9)	—	562
Other long-term liabilities (Note 5)	160,907	166,983
Deferred income taxes	753,663	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, 49,105,600 and 48,581,948 shares issued, respectively	9,643	9,594
Capital in excess of par value	435,467	423,603
Accumulated other comprehensive income (Note 11)	1,709	7,587
Retained earnings	1,632,730	1,533,517
Total shareholders' equity	2,079,549	1,974,301
Total liabilities and shareholders' equity	$ 3,899,524	$ 3,761,120

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$ 164,799	$ 131,166	$ 318,408	$ 266,931
Contract drilling	105,005	146,872	212,533	287,778
Gas gathering and processing	70,617	49,747	128,012	107,042
Total revenues	340,421	327,785	658,953	661,751
Expenses:				
Oil and natural gas:				
Operating costs	44,994	33,279	88,032	68,888
Depreciation, depletion, and amortization	55,335	57,153	107,318	109,350
Impairment of oil and natural gas properties (Note 2)	—	115,874	—	115,874
Contract drilling:				
Operating costs	63,590	74,819	129,592	150,992
Depreciation	17,908	21,238	35,168	42,566
Gas gathering and processing:				
Operating costs	59,557	42,363	108,967	89,976
Depreciation and amortization	8,214	5,312	15,370	10,446
General and administrative	9,679	8,376	18,352	15,380
Gain on disposition of assets	(3,483)	(651)	(3,399)	(1,239)
Total operating expenses	255,794	357,763	499,400	602,233
Income (loss) from operations	84,627	(29,978)	159,553	59,518
Other income (expense):				
Interest, net	(4,591)	(2,542)	(8,152)	(4,368)
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	16,344	1,387	10,420	(606)
Other	(91)	69	(157)	(64)
Total other income (expense)	11,662	(1,086)	2,111	(5,038)
Income (loss) before income taxes	96,289	(31,064)	161,664	54,480
Income tax expense (benefit):				
Current	2,117	(2,066)	4,634	(2,066)
Deferred	35,165	(9,696)	57,817	23,409
Total income taxes	37,282	(11,762)	62,451	21,343
Net income (loss)	$ 59,007	$ (19,302)	$ 99,213	$ 33,137
Net income (loss) per common share:				
Basic	$ 1.22	$ (0.40)	$ 2.06	$ 0.69
Diluted	$ 1.22	$ (0.40)	$ 2.05	$ 0.69

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Net income (loss)	$ 59,007	$ (19,302)	$ 99,213	$ 33,137
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $3,874, $17,256, ($2,504), and $16,214	6,091	27,226	(3,820)	25,490
Reclassification - derivative settlements, net of tax of $317, ($6,106), ($1,177), and ($9,270)	506	(9,564)	(1,831)	(14,576)
Ineffective portion of derivatives, net of tax of ($667), ($537), ($141), and $232	(1,050)	(850)	(227)	374
Comprehensive income (loss)	$ 64,554	$ (2,490)	$ 93,335	$ 44,425

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

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 99,213	$ 33,137
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	159,369	163,140
Impairment of oil and natural gas properties (Note 2)	—	115,874
Unrealized (gain) loss on derivatives	(9,561)	606
Deferred tax expense	57,817	23,409
Gain on disposition of assets	(3,399)	(1,239)
Stock compensation plans	10,654	7,978
Other, net	3,005	2,218
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(13,001)	1,675
Accounts payable	2,219	(28,587)
Material and supplies	(751)	(129)
Accrued liabilities	11,313	(2,151)
Other, net	1,010	(899)
Net cash provided by operating activities	317,888	315,032
INVESTING ACTIVITIES:		
Capital expenditures	(339,300)	(371,703)
Producing property and other acquisitions	—	(2,193)
Proceeds from disposition of assets	16,829	6,288
Net cash used in investing activities	(322,471)	(367,608)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	183,900	250,500
Payments under credit agreement	(185,000)	(217,600)
Proceeds from exercise of stock options	81	89
Book overdrafts	5,669	19,837
Net cash provided by financing activities	4,650	52,826
Net increase in cash and cash equivalents	67	250
Cash and cash equivalents, beginning of period	974	835
Cash and cash equivalents, end of period	$ 1,041	$ 1,085

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

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 June 30, 2013 and December 31, 2012;
- Statements of Operations for the three and six months ended June 30, 2013 and 2012;
- Statements of Comprehensive Income (Loss) for the three and six months ended June 30, 2013 and 2012; and
- Statements of Cash Flows for the six months ended June 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 six months ended June 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 six month periods ended June 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 August 6, 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 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 June 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 June 30, 2013, consisted of swaps and collars covering 3.5 MMBoe in 2013. The effect of those hedges on the June 30, 2013 ceiling test was a $9.4 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 9 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 3 – EARNINGS (LOSS) 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 June 30, 2013			
Basic earnings per common share	$ 59,007	48,208	$ 1.22
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	298	—
Diluted earnings per common share	$ 59,007	48,506	$ 1.22
For the three months ended June 30, 2012			
Basic earnings (loss) per common share	$ (19,302)	47,906	$ (0.40)
Effect of dilutive stock options, restricted stock, and SARs	—	—	—
Diluted earnings (loss) per common share	$ (19,302)	47,906	$ (0.40)

Due to the net loss for the three months ended June 30, 2012, approximately 224,000 weighted average shares related to stock options, restricted stock, and SARs were antidilutive and were excluded from the earnings per share calculation above. The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended June 30,	
	2013	2012
Stock options and SARs	250,901	292,901
Average exercise price	$ 52.72	$ 50.99

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the six months ended June 30, 2013			
Basic earnings per common share	$ 99,213	48,162	$ 2.06
Effect of dilutive stock options, restricted stock, and SARs	—	329	(0.01)
Diluted earnings per common share	$ 99,213	48,491	$ 2.05
For the six months ended June 30, 2012			
Basic earnings per common share	$ 33,137	47,868	$ 0.69
Effect of dilutive stock options, restricted stock, and SARs	—	245	—
Diluted earnings per common share	$ 33,137	48,113	$ 0.69

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

NOTE 4 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	June 30, 2013	December 31, 2012
	(In thousands)	
Employee costs	$ 19,269	$ 24,632
Lease operating expenses	12,612	10,903
Taxes	9,507	7,308
Interest payable	7,024	6,568
Other	10,420	4,687
Total accrued liabilities	$ 58,832	$ 54,098

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

Long-Term Debt

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

	June 30, 2013	December 31, 2012
	(In thousands)	
Credit agreement with an average interest rate of 1.9% and 2.9% at June 30, 2013 and December 31, 2012, respectively	$ 70,000	$ 71,100
6.625% senior subordinated notes due 2021, net of unamortized discount of $4.5 million at June 30, 2013 and $4.7 million at December 31, 2012	645,474	645,259
Total long-term debt	$ 715,474	$ 716,359

Credit Agreement. On September 5, 2012, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on September 13, 2016. 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 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 April 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 June 30, 2013, we had $70.0 million of outstanding borrowings under our credit agreement.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production, and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (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 June 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 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 June 30, 2013.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	June 30, 2013	December 31, 2012
	(In thousands)	
Asset retirement obligation (ARO) liability	$ 137,039	$ 146,159
Workers’ compensation	20,424	18,517
Separation benefit plans	8,562	7,972
Gas balancing liability	3,838	3,838
Deferred compensation plan	3,180	2,779
	173,043	179,265
Less current portion	12,136	12,282
Total other long-term liabilities	$ 160,907	$ 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 July 1, 2013 (and through 2017) are $12.1 million, $40.6 million, $5.6 million, $74.0 million, and $3.7 million, respectively.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

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

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

	Six Months Ended June 30,	
	2013	2012
	(In thousands)	
ARO liability, January 1:	$ 146,159	$ 96,446
Accretion of discount	2,825	2,126
Liability incurred	2,869	4,420
Liability settled	(3,516)	(1,447)
Revision of estimates (1)	(11,298)	(5,022)
ARO liability, June 30:	137,039	96,523
Less current portion	2,948	2,909
Total long-term ARO	$ 134,091	$ 93,614

(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 7 – NEW ACCOUNTING PRONOUNCEMENTS

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, U.S. 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 U.S. 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 U.S. 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 U.S. 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 10 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 8 – STOCK-BASED COMPENSATION

For the three and six months ended June 30, 2013, we recognized stock compensation expense for restricted stock awards of $4.3 million and $7.6 million, respectively. For the same period we also capitalized stock compensation cost for oil and natural gas properties of $0.9 million and $1.6 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.6 million and $2.9 million, respectively. For the three and six months ended June 30, 2012, we recognized stock compensation expense for restricted stock awards of $3.0 million and $5.3 million, respectively. For the same period we also capitalized stock compensation cost for oil and natural gas properties of $0.7 million and $1.3 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.1 million and $2.0 million, respectively. The remaining unrecognized compensation cost related to unvested awards at June 30, 2013 is approximately $25.9 million of which $4.2 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 of a year.

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).

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Shares granted:				
Employees	—	—	448,549	367,936
Non employee directors	21,128	24,606	21,128	24,606
	21,128	24,606	469,677	392,542
Estimated fair value (in millions):				
Employees	$ —	$ —	$ 21.0	$ 15.6
Non employee directors	0.9	1.0	0.9	1.0
	$ 0.9	$ 1.0	$ 21.9	$ 16.6
Percentage of shares granted expected to be distributed:				
Employees	N/A	N/A	94%	89%
Non employee directors	100%	100%	100%	100%

The restricted stock awards granted during the first three and six months of 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 six months of 2013 was $4.0 million.

NOTE 9 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs, and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of June 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).

At June 30, 2013, the following cash flow hedges were outstanding:

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

At June 30, 2013, the following non-designated hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'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 – Dec'14	Crude oil – collar	2,000 Bbl/day	$90.00-95.00	WTI – NYMEX
Jul'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)

After June 30, 2013, we entered into following non-designated hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan'14 – Dec'14	Crude oil – collar	2,000 Bbl/day	$90.00-97.15	WTI – NYMEX

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

		Derivative Assets Fair Value	
	Balance Sheet Location	June 30, 2013	December 31, 2012
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative asset	$ 4,215	$ 13,674
Long-term	Non-current derivative asset	—	—
Total derivatives designated as hedging instruments		4,215	13,674
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative asset	$ 5,680	$ 2,878
Long-term	Non-current derivative asset	4,887	—
Total derivatives not designated as hedging instruments		10,567	2,878
Total derivative assets		$ 14,782	$ 16,552

	Balance Sheet Location	Derivative Liabilities Fair Value June 30, 2013	December 31, 2012
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative liabilities	$ 879	$ 1,005
Long-term	Non-current derivative liabilities	—	—
Total derivatives designated as hedging instruments		879	1,005
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative liabilities	$ —	$ 943
Long-term	Non-current derivative liabilities	—	562
Total derivatives not designated as hedging instruments		—	1,505
Total derivative liabilities		$ 879	$ 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 and reclassify the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions are settled. As of June 30, 2013 and 2012, we had recognized a gain of $1.7 million and a gain of $30.3 million, net of tax, respectively, in accumulated OCI.

Based on market prices at June 30, 2013, we expect to transfer over the next 12 months (in the related month of settlement) a gain of approximately $1.7 million, net of tax, into revenue. The cash flow derivative instruments existing as of June 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 Operations. 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. Prior to October 2012, we reported all realized and unrealized gains (losses) 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 June 30 are as follows:

	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
	(In thousands)			
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net:				
Realized gains (losses) on derivatives not designated as hedges	$ (181)	$ —	$ 859	$ —
Unrealized gains on derivatives not designated as hedges	14,808	—	9,193	—
Unrealized gains (losses) on ineffectiveness of cash flow hedges	1,717	1,387	368	(606)
	$ 16,344	$ 1,387	$ 10,420	$ (606)

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (cash flow hedges) for the six months ended June 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2013	2012
	(In thousands)	
Commodity derivatives	$ 1,709	$ 30,314

(1) Net of taxes.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (cash flow hedges) for the three months ended June 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 Recognized in Income (2)	
		2013	2012	2013	2012
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ (823)	$ 15,670	$ —	$ —
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	1,717	1,387
Total		$ (823)	$ 15,670	$ 1,717	$ 1,387

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

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

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative	
		2013	2012
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	$ 14,627	$ —
Total		$ 14,627	$ —

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Operations (cash flow hedges) for the six months ended June 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 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	$ 3,008	$ 23,846	$ —	$ —
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	368	(606)
Total		$ 3,008	$ 23,846	$ 368	$ (606)

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

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

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative	
		2013	2012
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	$ 10,052	$ —
Total		$ 10,052	$ —

NOTE 10 – FAIR VALUE MEASUREMENTS

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

- Level 1 - unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2 - significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3 - generally unobservable inputs which are developed based on the best information available and may include our own internal data.

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

The following tables set forth our recurring fair value measurements:

	June 30, 2013				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$ 15,395	$ 1,781	$ 17,176	$ (2,394)	$ 14,782
Liabilities	(2,938)	(335)	(3,273)	2,394	(879)
	$ 12,457	$ 1,446	$ 13,903	$ —	$ 13,903

	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 June 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.

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	
	For the three months ended June 30, 2013	For the six months ended June 30, 2013
	(In thousands)	
Beginning of period	$ (2,536)	$ (595)
Total gains or losses (realized and unrealized):		
Included in earnings [(1)]	3,346	1,405
Included in other comprehensive income (loss)	—	—
Settlements	636	636
Transfers out of Level 3 into Level 2	—	—
End of period	$ 1,446	$ 1,446
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ 3,982	$ 2,041

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

	Commodity Collars	
	For the three months ended June 30, 2012	For the six months ended June 30, 2012
	(In thousands)	
Beginning of period	$ 13,912	$ 33,615
Total gains or losses (realized and unrealized):		
Included in earnings [(1)]	5,456	16,874
Included in other comprehensive income (loss)	(5,687)	(3,576)
Settlements	(5,551)	(16,859)
Transfers out of Level 3 into Level 2	—	(21,924)
End of period	$ 8,130	$ 8,130
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ (95)	$ 15

(1) Commodity collars are reported in the Unaudited Condensed Consolidated Statements of Operations in oil and natural gas revenues (for cash flow hedges) and gain (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 June 30, 2013:

Commodity [(1)]	Fair Value	Valuation Technique	Unobservable Input	Range
	(In thousands)			
Oil collars	$ 1,781	Discounted cash flow	Forward commodity price curve	($5.01) - $9.44
Natural gas collar	$ (335)	Discounted cash flow	Forward commodity price curve	($0.34) - $0.10

(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 June 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 June 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 June 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 June 30, 2013 and December 31, 2012 were $645.5 million and $645.3 million, respectively. We estimated the fair value of these Notes using quoted marked prices at June 30, 2013 and December 31, 2012 which were $676.0 million and $687.7 million, respectively. These Notes would be classified as Level 2.

NOTE 11 – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Net Gains (Losses) on Cash Flow Hedges	
	2013	2012
	(In thousands)	
Balance at April 1:	$ (3,838)	$ 13,503
Other comprehensive income before reclassification	6,091	27,226
Amounts reclassified from accumulated other comprehensive income	(544)	(10,415)
New current-period other comprehensive income	5,547	16,811
Balance at June 30:	$ 1,709	$ 30,314

Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Operations for the three months ended June 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	$ (823)	$ 15,670	Oil and natural gas revenues
Commodity derivatives	1,717	1,387	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net
	894	17,057	Total before tax
	(350)	(6,642)	Tax expense
Total reclassification for the period	$ 544	$ 10,415	Net of tax

Changes in accumulated other comprehensive income (loss) by component, net of tax, for the six months ended June 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 before reclassification	(3,820)	25,490
Amounts reclassified from accumulated other comprehensive income	(2,058)	(14,202)
New current-period other comprehensive income	(5,878)	11,288
Balance at June 30:	$ 1,709	$ 30,314

Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Operations for the six months ended June 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	$ 3,008	$ 23,846	Oil and natural gas revenues
Commodity derivatives	368	(606)	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net
	3,376	23,240	Total before tax
	(1,318)	(9,038)	Tax expense
Total reclassification for the period	$ 2,058	$ 14,202	Net of tax

NOTE 12 – INDUSTRY SEGMENT INFORMATION

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

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

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

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. Our production in Canada is not significant.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)		(In thousands)	
Revenues:				
Oil and natural gas	$ 164,799	$ 131,166	$ 318,408	$ 266,931
Contract drilling	118,660	160,925	238,013	313,384
Elimination of inter-segment revenue	(13,655)	(14,053)	(25,480)	(25,606)
Contract drilling net of inter-segment revenue	105,005	146,872	212,533	287,778
Gas gathering and processing	92,910	65,901	173,066	140,156
Elimination of inter-segment revenue	(22,293)	(16,154)	(45,054)	(33,114)
Gas gathering and processing net of inter-segment revenue	70,617	49,747	128,012	107,042
Total revenues	$ 340,421	$ 327,785	$ 658,953	$ 661,751
Operating income (loss):				
Oil and natural gas	$ 64,470	$ (75,140) (2)	$ 123,058	$ (27,181) (2)
Contract drilling	23,507	50,815	47,773	94,220
Gas gathering and processing	2,846	2,072	3,675	6,620
Total operating income (loss) (1)	90,823	(22,253)	174,506	73,659
General and administrative	(9,679)	(8,376)	(18,352)	(15,380)
Gain on disposition of assets	3,483	651	3,399	1,239
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	16,344	1,387	10,420	(606)
Interest expense, net	(4,591)	(2,542)	(8,152)	(4,368)
Other	(91)	69	(157)	(64)
Income (loss) before income taxes	$ 96,289	$ (31,064)	$ 161,664	$ 54,480

(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).

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 June 30, 2013, and the related Unaudited Condensed Consolidated Statements of Operations and Comprehensive Income for the three and six-month periods ended June 30, 2013 and 2012 and the Unaudited Condensed Consolidated Statements of Cash Flows for the six-month periods ended June 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 operations, 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
August 6, 2013

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

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

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

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

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

General

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

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

Our 2013 current capital budget for all of our business segments forecasts a 6% increase over our 2012 capital expenditures, excluding acquisitions. Our oil and natural gas segment's capital budget is $586.0 million, a 16% increase over 2012, excluding acquisitions and ARO liability. Our drilling segment's capital budget is $98.0 million, a 26% increase over 2012. Our mid-stream segment's capital budget is $105.0 million, a 36% decrease from 2012, excluding acquisitions.

Our 2013 current capital expenditures budget is based on anticipated realized prices for the year of $93.05 per barrel of oil, $32.05 per barrel of NGLs, and $3.56 per Mcf. This budget is subject to possible periodic adjustments for various reasons including changes in anticipated commodity prices and industry conditions. Funding for the budget will come primarily from internally generated cash flow, proceeds from non-core asset sales and, if necessary, borrowings under our credit agreement.

Executive Summary

Oil and Natural Gas

Second quarter 2013 production from our oil and natural gas segment was 4,109,000 barrels of oil equivalent (Boe), a 3% increase over the first quarter of 2013 and a 23% increase over the second quarter of 2012. The first quarter of 2013 was lower due primarily to adverse weather conditions in February and fewer days in the quarter. The increase over the second quarter of 2012 came primarily from new wells completed in oil and NGLs rich prospects that were brought online and from production associated with 2012 acquisitions.

Second quarter 2013 oil and natural gas revenues increased 7% over the first quarter of 2013 and increased 23% over the second quarter of 2012. The increase over the first quarter of 2013 was due primarily to increases in oil and NGLs production coupled with higher natural gas prices somewhat offset by decreases in natural gas production and lower NGLs prices. The increase over the second quarter of 2012 was due primarily to increased production along with higher oil and natural gas prices.

Our oil prices for the second quarter of 2013 stayed relatively flat compared to the first quarter of 2013 and increased 3% over the second quarter of 2012. Our NGLs prices decreased 13% and 6% from the first quarter of 2013 and second quarter of 2012, respectively. Our natural gas prices increased 11% and 20% over the first quarter of 2013 and second quarter of 2012, respectively.

During the second quarter of 2012, we recorded a non-cash ceiling write down of $115.9 million pre-tax ($72.1 million, net of tax). For 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 natural gas and oil 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.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 8% over the first quarter of 2013 and increased 22% over the second quarter of 2012. The increases were due primarily to increases in production and natural gas prices partially offset by increases in gross production taxes and lease operating expenses and lower liquids prices.

Operating cost per Boe produced for the second quarter of 2013 increased 1% over the first quarter of 2013 and increased 10% over the second quarter of 2012. Costs were higher between the second and first quarter of 2013 primarily due to higher gross production taxes and lease operating expenses. Costs were higher between the second quarter of 2013 and the second quarter of 2012 due to additional wells from acquisitions and wells completed in the last half of 2012.

For 2013, Unit has hedged approximately 8,330 Bbls per day of its oil production and approximately 100,000 Mmbtu per day of natural gas production. 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, Unit currently has hedged 7,000 Bbls per day of oil production and 50,000 Mmbtu per day of natural gas production. The oil production is hedged by swaps for 3,000 Bbls per day and collars for 4,000 Bbls per day. The swap transactions were executed at an average price of $91.77 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.

As of June 30, 2013, we completed drilling 61 wells (37.27 net wells). 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. For 2013, we plan to participate in the drilling of 170 wells. Our oil and natural gas segment's capital budget is $586.0 million, a 16% increase over 2012, excluding acquisitions and ARO liability.

Contract Drilling

The rate at which our drilling rigs were used ("our utilization rate") for the second quarter 2013 was 51%, compared to 52% and 60% for the first quarter of 2013 and the second quarter of 2012, respectively.

Dayrates for the second quarter of 2013 averaged $19,601, essentially unchanged from the first quarter of 2013 and a 3% decrease from the second 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 second quarter of 2013 was essentially unchanged from the first quarter of 2013 and decreased 43% from the second quarter of 2012. The decrease from the second quarter of 2012 was due primarily to 15% fewer drilling rigs operating and lower per day revenue. The second quarter of 2012 included $15.1 million in revenue for early termination fees on three drilling rigs that were under long-term contracts but were terminated early by the operator.

Operating cost per day for the second quarter of 2013 decreased 3% from the first quarter of 2013 and decreased 1% from the second quarter of 2012. The decreases were primarily due to lower per day direct costs. With the weakening of natural gas prices, over the last several years the demand for rigs in our contract drilling segment shifted to drilling wells focused on increasing oil and NGL production. Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGL's. Part of the shift from natural gas 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 rigs utilized by our customers.

As of June 30, 2013, we had 27 term drilling contracts with original terms ranging from six months to three years. Sixteen of these contracts are up for renewal in 2013, 13 in the third quarter, and three in the fourth quarter, and 11 are up for renewal in 2014 and later. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate.

During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party and we placed a new 1,500 horsepower, diesel-electric drilling rig into service, initially 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 second quarter of 2013, we sold a 2,000 horsepower electric drilling rig to an unaffiliated third-party. Subsequent to June 30, 2013, we sold another 2,000 horsepower electric drilling rig.

Our anticipated 2013 capital expenditures for this segment are $98.0 million, a 26% increase over 2012. 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 a new prototype 1,500 horsepower AC electric drilling rig of proprietary design. The drilling rig is expected to be operational in the fourth quarter of 2013, and will operate initially for our oil and natural gas segment.

Mid-Stream

Second quarter 2013 liquids sold per day increased 21% from the first quarter of 2013 and decreased 19% from the second quarter of 2012. Volumes in the first quarter of 2013 were lower due to ethane rejection and from wells being shut in due to winter weather conditions during February of 2013. The decrease from the second quarter of 2012 was primarily due to one of our customers completing construction of their own processing plant in the second half of 2012 and moving their volumes off our system. For the second quarter of 2013, gas processed per day increased 6% over the first quarter of 2013 and decreased 4% from the second quarter of 2012. This increase over the first quarter is primarily due to connecting new wells to both existing and newly constructed systems. For the second quarter of 2013, gas gathered per day increased 20% over the first quarter of 2013 and increased 24% over the second quarter of 2012. The increases were primarily from new well connects.

NGLs prices in the second quarter of 2013 decreased 12% from the prices received in the first quarter of 2013 and increased 24% over the prices received in the second 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 second quarter of 2013 increased 39% over the first quarter of 2013 and increased 50% over the second quarter of 2012. Revenues increased over the comparative periods primarily due to the price received for gas sold, a 19% price increase over the first quarter of 2013 and a 95% price increase over the second quarter of 2012. The increases in direct profit from increased revenues were somewhat offset by higher cost of gas purchased, general and administrative expenses, and field direct expenses . Total operating cost for our mid-stream segment for the second quarter of 2013 increased 21% over the first quarter of 2013 and increased 41% over the second quarter of 2012.

After relocating two processing plants to our new Reno 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 are constructing a new gathering system and processing facility in Reno County, Kansas. This system is under construction and will consist of approximately 35 miles of gathering pipeline and two processing plants which were relocated from our Hemphill facility, a five MMcf per day refrigeration plant and a 20 MMcf per day turbo expander plant. At this facility we are currently gathering gas and the processing plants are expected to be operational in the third quarter of 2013.

At our Cashion facility, we completed the extension of our gathering system to the west approximately four miles at a capital cost of $3.8 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 136 miles of pipe, which includes a 26 mile extension to connect our existing Remington plant and a 20 mile NGL line to Medford, Oklahoma 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 at our Bellmon facility. This new cryogenic processing plant is expected to be operational in the fourth quarter of 2013.

In the Appalachian area, we are continuing to expand our Pittsburgh Mills gathering system which is located in Allegheny County, Pennsylvania. We have completed the first phase of this project which includes approximately 14 miles of gathering pipeline and related compressor station in which we have installed three compressors. We currently have 19 wells connected to this system with a current gathered volume of approximately 68 MMcf per day.

Our anticipated 2013 capital expenditures for the midstream segment are $105.0 million, a 36% decrease from 2012, excluding acquisitions. As of June 30, 2013 we have incurred capital expenditures of $50.2 million.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreement 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 June 30, 2013 and 2012 and for the six months ended June 30, 2013 and 2012:

	June 30,		%
	2013	2012	Change
	(In thousands except percentages)		
Working capital	$ 9,738	$ 41,538	(77)%
Long-term debt	$ 715,474	$ 332,900	115 %
Shareholders' equity	$ 2,079,549	$ 2,000,378	4 %
Ratio of long-term debt to total capitalization	26%	14%	86 %
Net income	$ 99,213	$ 33,137	199 %
Net cash provided by operating activities	$ 317,888	$ 315,032	1 %
Net cash used in investing activities	$ (322,471)	$ (367,608)	(12)%
Net cash provided by financing activities	$ 4,650	$ 52,826	(91)%

The following table summarizes certain operating information:

	Six Months Ended June 30,		%
	2013	2012	Change
Oil and Natural Gas:			
Oil production (MBbls)	1,656	1,506	10 %
Natural gas liquids production (MBbls)	1,739	1,330	31 %
Natural gas production (MMcf)	28,107	22,688	24 %
Average oil price per barrel received	$95.05	$94.04	1 %
Average oil price per barrel received excluding hedges	$91.75	$94.53	(3)%
Average NGLs price per barrel received	$32.47	$35.53	(9)%
Average NGLs price per barrel received excluding hedges	$32.47	$34.19	(5)%
Average natural gas price per mcf received	$3.47	$3.19	9 %
Average natural gas price per mcf received excluding hedges	$3.53	$2.18	62 %
Contract Drilling:			
Average number of our drilling rigs in use during the period	65.8	79.1	(17)%
Total number of drilling rigs owned at the end of the period	126	128	(2)%
Average dayrate	$19,590	$19,979	(2)%
Mid-Stream:			
Gas gathered—Mcf/day	299,582	239,837	25 %
Gas processed—Mcf/day	134,016	134,744	(1)%
Gas liquids sold—gallons/day	464,483	576,089	(19)%
Number of natural gas gathering systems	40	36	11 %
Number of processing plants	15	11	36 %

At June 30, 2013, we had unrestricted cash totaling $1.0 million and had borrowed $70.0 million 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 positive working capital of $9.7 million and $41.5 million, respectively as of June 30, 2013 and 2012, respectively. The effect of our hedging activity increased working capital by $7.9 million as of June 30, 2013 and increased working capital by $26.3 million as of June 30, 2012.

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

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

Based on our first six 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 $449,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of hedging, during the first six months of 2013 was $3.47 compared to $3.19 for the first six months of 2012. Based on our first six months of 2013 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $267,000 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 $277,000 per month ($3.3 million annualized) change in our pre-tax operating cash flow. In the first six months of 2013, our average oil price per barrel received, including the effect of hedging, was $95.05 compared with an average oil price, including the effect of hedging, of $94.04 in the first six months of 2012 and our first six months of 2013 average NGLs price per barrel received, including the effect of hedging, was $32.47 compared with an average NGLs price per barrel of $35.53 in the first six 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 June 30, 2013, the 12-month average unescalated prices were $91.60 per barrel of oil, $37.52 per barrel of NGLs, and $3.44 per Mcf of natural gas, then adjusted for price differentials. We were not required to take a write-down in the second 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.

At June 30, 2012, the 12-month average unescalated prices were $95.67 per barrel of oil, $56.04 per barrel of NGLs, and $3.15 per Mcf of natural gas, adjusted for price differentials. The unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGL, 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).

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 rigs in our contract drilling segment shifted to drilling wells focused on increasing oil and NGL production. Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGL's. Part of the shift from natural gas 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 rigs utilized by our customers. For the first six months of 2013, our average dayrate was $19,590 per day compared to $19,979 per day for the first six months of 2012. The average number of our drilling rigs used in the first six months of 2013 was 65.8 drilling rigs (52%) compared with 79.1 drilling rigs (62%) in the first six months of 2012. Based on the average utilization of our drilling rigs during the first six months of 2013, a $100 per day change in dayrates has a $6,580 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 recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $25.5 million and $25.6 million for the six months of 2013 and 2012, respectively, from our contract drilling segment and eliminated the associated operating expense of $18.4 million and $16.7 million during the six months of 2013 and 2012, respectively, yielding $7.1 million and $8.9 million during the six 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, 40 gathering systems, and approximately 1,411 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 six months of 2013 and 2012, our mid-stream operations purchased $41.3 million and $31.1 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $3.8 million and $2.0 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 299,582 Mcf per day in the first six months of 2013 compared to 239,837 Mcf per day in the first six months of 2012. It processed an average of 134,016 Mcf per day in the first six months of 2013 compared to 134,744 Mcf per day in the first six months of 2012. The amount of NGLs sold was 464,483 gallons per day in the first six months of 2013 compared to 576,089 gallons per day in the first six months of 2012. Gas gathering volumes per day in the first six months of 2013 increased 25% compared to the first six months of 2012 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes decreased 1% from the comparative six months and NGLs sold decreased 19% 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 six months ended 2012 in liquids sold, gas gathered, and gas processed, partially offset by the addition of new wells connected.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On September 5, 2012, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on September 13, 2016. 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. At June 30, 2013 and July 25, 2013, borrowings were $70.0 million and $60.0 million, respectively.

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 April 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.

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

The credit agreement prohibits, among other things:

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

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

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

As of June 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, 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 June 30, 2013.

Capital Requirements

Oil and Natural Gas Segment Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Any decision to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 61 gross wells (37.27 net wells) in the first six months of 2013 compared to 93 gross wells (41.17 net wells) in the first six months of 2012. Total capital expenditures for oil and gas properties on the full cost method for the first six months of 2013 by this segment, excluding a $11.9 million reduction in the ARO liability, totaled $231.9 million. Total capital expenditures for the first six months of 2012, excluding a $2.0 million reduction in the ARO liability adjustments and $2.2 million for acquisitions, totaled $246.9 million.

Currently we plan to participate in drilling approximately 170 gross wells in 2013 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $586.0 million. Whether we are able to drill the full number of wells planned is dependent on a number of factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party and we placed a new 1,500 horsepower, diesel-electric drilling rig into service, initially 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 second quarter of 2013, we sold a 2,000 horsepower electric drilling rig to an unaffiliated third-party. Subsequent to June 30, 2013, we sold another 2,000 horsepower electric drilling rig. We currently have 125 drilling rigs in our fleet.

Our anticipated 2013 capital expenditures for this segment are $98.0 million. At June 30, 2013, we had commitments to purchase approximately $4.5 million for drilling equipment over the next twelve months. During 2013, we will be constructing a new prototype 1,500 horsepower AC electric drilling rig of proprietary design. The drilling rig will operate initially for our oil and natural gas segment when completed. We have spent $21.2 million for capital expenditures during the first six months of 2013 compared to $53.2 million in the first six months of 2012.

Mid-Stream Acquisitions and Capital Expenditures. After relocating two processing plants to our new Reno 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 are constructing a new gathering system and processing facility in Reno County, Kansas. This system is under construction and will consist of approximately 35 miles of gathering pipeline and two processing plants which were relocated from our Hemphill facility, a five MMcf per day refrigeration plant and a 20 MMcf per day turbo expander plant. At this facility we are currently gathering gas and the processing plants are expected to be operational in the third quarter of 2013.

At our Cashion facility, we completed the extension of our gathering system to the west approximately four miles at a capital cost of $3.8 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 136 miles of pipe, which includes a 26 mile extension to connect our existing Remington plant and a 20 mile NGL line to Medford, Oklahoma 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 at our Bellmon facility. This new cryogenic processing plant is expected to be operational in the fourth quarter of 2013.

In the Appalachian area, we are continuing to expand our Pittsburgh Mills gathering system which is located in Allegheny County, Pennsylvania. We have completed the first phase of this project which includes approximately 14 miles of gathering pipeline and related compressor station in which we have installed three compressors. We currently have 19 wells connected to this system with a current gathered volume of approximately 68 MMcf per day.

During the first six months of 2013, our mid-stream segment incurred $50.2 million in capital expenditures as compared to $58.6 million in the first six months of 2012. For 2013, our estimated capital expenditures (excluding acquisitions) are $105.0 million. At June 30, 2013, we had a commitment to purchase a 60 MMcf per day processing plant with a final payment of $1.1 million within the next twelve months.

Contractual Commitments

At June 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)]	$ 1,095,642	$ 44,423	$ 88,846	$ 156,404	$ 805,969
Operating leases [(2)]	12,339	8,411	3,676	252	—
Drill pipe, drilling components, and equipment purchases [(3)]	5,583	5,583	—	—	—
Total contractual obligations	$ 1,113,564	$ 58,417	$ 92,522	$ 156,656	$ 805,969

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our June 30, 2013 interest rates of 6.625% for the Notes and 1.9% for the credit agreement.

(2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through 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 $4.5 million for drilling equipment and $1.1 million for a processing plant over the next twelve months.

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

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	**Total Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
	(In thousands)				
Deferred compensation plan [(1)]	$ 3,180	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [(2)]	$ 8,562	$ 527	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$ 879	$ 879	$ —	$ —	$ —
Asset retirement liability [(3)]	$ 137,039	$ 2,948	$ 43,362	$ 6,452	$ 84,277
Gas balancing liability [(4)]	$ 3,838	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [(5)]	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability [(6)]	$ 20,424	$ 8,661	$ 2,897	$ 1,254	$ 7,612

(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 $8,000 and $43,000 in 2013 and 2012, respectively through the first six 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 covering part of the interest rate payable under our credit agreement as well as the prices to be received for a portion of our oil, NGLs, and natural gas production. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. 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.

Commodity Hedges. Our commodity hedging 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 June 30, 2013, based on our second 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	58%	30%	88%	53%
Daily natural gas production	52%	13%	65%	33%

With respect to the commodities subject to our hedges, the use of hedging limits the risk of adverse downward price movements. However, it also limits increases in 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 June 30, 2013 evaluation, we believe the risk of non-performance by our counterparties is not material. At June 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:

	June 30, 2013
	(In millions)
The Bank of Nova Scotia	$ 5.8
Bank of Montreal	4.2
Comerica Bank	3.2
Canadian Imperial Bank of Commerce	1.1
BBVA Compass Bank	0.5
Bank of America	(0.9)
Total assets (liabilities)	$ 13.9

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At June 30, 2013, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current assets of $9.9 million and $4.9 million, respectively and current derivative liabilities of $0.9 million. At June 30, 2012, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $42.8 million and $9.5 million, respectively, and non-current derivative liabilities of $0.6 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 June 30, 2013, we had recognized a gain of $1.7 million, net of tax, from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at June 30, 2013, we expect to transfer to earnings a gain of approximately $1.7 million, net of tax, included in accumulated OCI during the next 12 months in the related month of production. The commodity derivative instruments under cash flow accounting existing as of June 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 Operations. 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 other comprehensive income 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. Prior to October 2012, we reported all realized and unrealized gains (losses) 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 June 30 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net:				
Realized gains (losses) on derivatives not designated as hedges	$ (181)	$ —	$ 859	$ —
Unrealized gains on derivatives not designated as hedges	14,808	—	9,193	—
Unrealized gains (losses) on ineffectiveness of cash flow hedges	1,717	1,387	368	(606)
	$ 16,344	$ 1,387	$ 10,420	$ (606)

Stock and Incentive Compensation

During the first six 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 six months of 2013, we recognized $3.3 million in compensation expense and capitalized $0.7 million for these awards. During the first six months of 2013, we recognized compensation expense of $7.6 million for all of our restricted stock, stock options, and SAR grants and capitalized $1.6 million of compensation cost for oil and natural gas properties.

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 six months of 2013 and 2012, the total we received for all of these fees was $0.3 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

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, U.S. 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 U.S. 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 U.S. 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 U.S. 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 10 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

Results of Operations

Quarter Ended June 30, 2013 versus Quarter Ended June 30, 2012

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

	Quarter Ended June 30,		Percent Change
	2013	2012	
Total revenue	$ 340,421,000	$ 327,785,000	4 %
Net income (loss)	$ 59,007,000	$ (19,302,000)	NM
Oil and Natural Gas:			
Revenue	$ 164,799,000	$ 131,166,000	26 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 44,994,000	$ 33,279,000	35 %
Average oil price (Bbl)	$ 94.89	$ 92.43	3 %
Average NGLs price (Bbl)	$ 30.32	$ 32.34	(6)%
Average natural gas price (Mcf)	$ 3.65	$ 3.03	20 %
Oil production (Bbl)	859,000	786,000	9 %
NGLs production (Bbl)	935,000	674,000	39 %
Natural gas production (Mcf)	13,887,000	11,287,000	23 %
Depreciation, depletion and amortization rate (Boe)	$ 13.20	$ 16.92	(22)%
Depreciation, depletion and amortization	$ 55,335,000	$ 57,153,000	(3)%
Impairment of oil and natural gas properties	—	115,874,000	(100)%
Contract Drilling:			
Revenue	$ 105,005,000	$ 146,872,000	(29)%
Operating costs excluding depreciation	$ 63,590,000	$ 74,819,000	(15)%
Percentage of revenue from daywork contracts	100%	100%	
Average number of drilling rigs in use	65.2	76.7	(15)%
Average dayrate on daywork contracts	$ 19,601	$ 20,128	(3)%
Depreciation	$ 17,908,000	$ 21,238,000	(16)%
Mid-Stream:			
Revenue	$ 70,617,000	$ 49,747,000	42 %
Operating costs excluding depreciation and amortization	$ 59,557,000	$ 42,363,000	41 %
Depreciation and amortization	$ 8,214,000	$ 5,312,000	55 %
Gas gathered—Mcf/day	326,039	262,269	24 %
Gas processed—Mcf/day	138,130	144,257	(4)%
Gas liquids sold—gallons/day	508,189	629,350	(19)%
General and administrative expense	$ 9,679,000	$ 8,376,000	16 %
Gain on disposition of assets	$ 3,483,000	$ 651,000	NM
Other income (expense): (2)			
Interest expense, net	$ (4,591,000)	$ (2,542,000)	81 %
Gain on derivatives not designated as hedges and hedge ineffectiveness	$ 16,344,000	$ 1,387,000	NM
Other	$ (91,000)	$ 69,000	NM
Income tax expense (benefit)	$ 37,282,000	$ (11,762,000)	NM
Average interest rate	6.2%	5.6%	11 %
Average long-term debt outstanding	$ 719,710,000	$ 327,642,000	120 %

(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 realized and unrealized 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.

Oil and Natural Gas

Oil and natural gas revenues increased $33.6 million or 26% in the second quarter of 2013 as compared to the second quarter of 2012 due to a 23% 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 second quarter of 2013, as compared to the second quarter of 2012, oil production increased 9%, NGLs production increased 39%, and natural gas production increased 23%. Average oil prices increased 3% to $94.89 per barrel, NGLs prices decreased 6% to $30.32 per barrel, and natural gas prices increased 20% to $3.65 per Mcf.

Oil and natural gas operating costs increased $11.7 million or 35% between the comparative second quarters of 2013 and 2012 due to higher lease operating expenses, gross production taxes, and increased general and administrative expense from both higher cost per equivalent barrel produced and increases due to owning more wells. Lease operating expenses per Boe increased 12% to $7.01.

Depreciation, depletion, and amortization ("DD&A") decreased $1.8 million due primarily to a 22% decrease in our DD&A rate partially offset by a 23% increase in equivalent production. The decrease in our DD&A rate in the second quarter of 2013 compared to the second quarter 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 $41.9 million or 29% in the second quarter of 2013 versus the second quarter of 2012. The decrease was due primarily to a 15% decrease in the average number of drilling rigs in use as well as a 3% decrease in the average dayrate in the second quarter of 2013 compared to the second quarter of 2012. Average drilling rig utilization decreased from 76.7 drilling rigs in the second quarter of 2012 to 65.2 drilling rigs in the second quarter of 2013. During the second 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 $15.1 million.

Drilling operating costs decreased $11.2 million or 15% between the comparative second quarters of 2013 and 2012. The decrease was due primarily to the decrease in utilization. Contract drilling depreciation decreased $3.3 million or 16% also due primarily to the decrease in utilization.

Mid-Stream

Our mid-stream revenues increased $20.9 million or 42% in the second quarter of 2013 as compared to the second quarter of 2012. The average price for natural gas sold increased 95% and the average price for NGLs sold increased 24%. Gas processing volumes per day decreased 4% between the comparative quarters and NGLs sold per day decreased 19% between the comparative quarters. One of our customers completed construction of their own processing plant and moved their volumes off our system during the second half of 2012, resulting in decreases in gas processed and NGLs sold from the second quarter of 2012 and partially offset the gains in gas volumes gathered and processed. These decreases in volumes were offset by connecting new wells to our existing and newly constructed systems. Gas gathering volumes per day increased 24% primarily from new well connections.

Operating costs increased $17.2 million or 41% in the second quarter of 2013 compared to the second quarter of 2012 primarily due to a 46% increase in prices paid for natural gas purchased partially offset by a 4% decrease in the per day gas volumes purchased. Depreciation and amortization increased $2.9 million, or 55%, primarily due to additional assets placed into service throughout 2012 and the first half of 2013.

General and Administrative

General and administrative expenses increased $1.3 million or 16% in the second quarter of 2013 compared to the second 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 $2.8 million in the second quarter of 2013 compared to the second quarter of 2012 primarily due to the sale of a drilling rig.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $2.0 million between the comparative second 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 5.6% to 6.2% and our average debt outstanding was $392.1 million higher in the second quarter of 2013 as compared to the second quarter of 2012 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.

Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net increased $15.0 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense (Benefit)

Income tax expense (benefit) changed from a benefit of $11.8 million in the second quarter of 2012, due to the non-cash ceiling test write-down mentioned above, to an expense of $37.3 million in the second quarter of 2013. Our effective tax rate was 38.7% for the second quarter of 2013 and 37.9% for the second quarter of 2012. Current income tax expense was $2.1 million for the second quarter of 2013 compared to a benefit of $2.1 million for the second quarter of 2012 with the current amount primarily due to the exhaustion of net operating loss carrybacks. We paid $7.1 million of income taxes in the second quarter of 2013.

Six Months Ended June 30, 2013 versus Six Months Ended June 30, 2012

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Percent Change
Total revenue	$ 658,953,000	$ 661,751,000	— %
Net income	$ 99,213,000	$ 33,137,000	199 %
Oil and Natural Gas:			
Revenue	$ 318,408,000	$ 266,931,000	19 %
Operating costs excluding depreciation, depletion, amortization and impairment	$ 88,032,000	$ 68,888,000	28 %
Average oil price (Bbl)	$ 95.05	$ 94.04	1 %
Average NGLs price (Bbl)	$ 32.47	$ 35.53	(9)%
Average natural gas price (Mcf)	$ 3.47	$ 3.19	9 %
Oil production (Bbl)	1,656,000	1,506,000	10 %
NGLs production (Bbl)	1,739,000	1,330,000	31 %
Natural gas production (Mcf)	28,107,000	22,688,000	24 %
Depreciation, depletion and amortization rate (Boe)	$ 13.08	$ 16.38	(20)%
Depreciation, depletion and amortization	$ 107,318,000	$ 109,350,000	(2)%
Impairment of oil and natural gas properties	$ —	$ 115,874,000	(100)%
Contract Drilling:			
Revenue	$ 212,533,000	$ 287,778,000	(26)%
Operating costs excluding depreciation	$ 129,592,000	$ 150,992,000	(14)%
Percentage of revenue from daywork contracts	100%	100%	
Average number of drilling rigs in use	65.8	79.1	(17)%
Average dayrate on daywork contracts	$ 19,590	$ 19,979	(2)%
Depreciation	$ 35,168,000	$ 42,566,000	(17)%
Mid-Stream:			
Revenue	$ 128,012,000	$ 107,042,000	20 %
Operating costs excluding depreciation and amortization	$ 108,967,000	$ 89,976,000	21 %
Depreciation and amortization	$ 15,370,000	$ 10,446,000	47 %
Gas gathered—Mcf/day	299,582	239,837	25 %
Gas processed—Mcf/day	134,016	134,744	(1)%
Gas liquids sold—gallons/day	464,483	576,089	(19)%
General and administrative expense	$ 18,352,000	$ 15,380,000	19 %
Gain on disposition of assets	$ 3,399,000	$ 1,239,000	174 %
Other income (expense): (2)			
Interest expense, net	$ (8,152,000)	$ (4,368,000)	(87)%
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness	$ 10,420,000	$ (606,000)	NM
Other	$ (157,000)	$ (64,000)	(145)%
Income tax expense	$ 62,451,000	$ 21,343,000	193 %
Average interest rate	6.3%	5.7%	11 %
Average long-term debt outstanding	$ 719,443,000	$ 315,864,000	128 %

(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 realized and unrealized 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.

Oil and Natural Gas

Oil and natural gas revenues increased $51.5 million or 19% in the first six months of 2013 as compared to the first six 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 six months of 2013, as compared to the first six months of 2012, oil production increased 10%, NGLs production increased 31%, and natural gas production increased 24%. Average oil prices increased 1% to $95.05 per barrel, NGLs prices decreased 9% to $32.47 per barrel, and natural gas prices increased 9% to $3.47 per Mcf.

Oil and natural gas operating costs increased $19.1 million or 28% between the comparative first six months of 2013 and 2012 due primarily to higher lease operating expenses and increased general and administrative expense from both higher cost per equivalent barrel produced and increases due to more wells owned. Lease operating expenses per Boe increased 6% to $6.95.

DD&A decreased $2.0 million between the comparative periods due primarily to a 20% decrease in our DD&A rate partially offset by a 22% increase in equivalent production. The decrease in our DD&A rate in the first six months of 2013 compared to the first six 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 $75.2 million or 26% in the first six months of 2013 versus the first six months of 2012. The decrease was due primarily to a 17% decrease in the average number of drilling rigs in use and a 2% decrease in the average dayrate in the first six months of 2013 compared to the first six months of 2012. Average drilling rig utilization decreased from 79.1 drilling rigs in the first six months of 2012 to 65.8 drilling rigs in the first six months of 2013. During the first six months of 2012, we had four 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 $15.8 million.

Drilling operating costs decreased $21.4 million or 14% between the comparative first six months of 2013 and 2012. The decrease was due primarily to the decrease in utilization. Contract drilling depreciation decreased $7.4 million or 17% also due primarily to the decrease in utilization.

Mid-Stream

Our mid-stream revenues increased $21.0 million or 20% for the first six months of 2013 as compared to the first six months of 2012. The average price for natural gas sold increased 60%. Gas processing volumes per day decreased 1% between the comparative periods and NGLs sold per day decreased 19% between the comparative periods. Gas processed and 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. These decreases in volumes were offset by connecting new wells to our existing and newly constructed systems. Gas gathering volumes per day increased 25% primarily from new well connections.

Operating costs increased $19.0 million or 21% in the first six months of 2013 compared to the first six months of 2012 primarily due to a 24% increase in prices paid for natural gas purchased. Depreciation and amortization increased $4.9 million, or 47%, primarily due to additional assets placed into service throughout 2012 and the first six months of 2013.

General and Administrative

General and administrative expenses increased $3.0 million or 19% in the first six months of 2013 compared to the first six 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 $2.2 million in the first six months of 2013 compared to the first six months of 2012 primarily due to the sale of a drilling rig.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $3.8 million between the comparative first six 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 5.7% to 6.3% and our average debt outstanding was $403.6 million higher in the first six months of 2013 as compared to the first six 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.

Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net increased $11.0 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 $41.1 million or 193% in the first six months of 2013 compared to the first six months of 2012 primarily due to increased income. Our effective tax rate was 38.6% for the first six months of 2013 and 39.2% for the first six months of 2012. Current income tax expense was $4.6 million for the first six months of 2013 compared to a benefit of $2.1 million for the first six months of 2012 with the current amount due to the exhaustion of net operating loss carrybacks. We paid $7.1 million of income taxes in the first six 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," and similar expressions are used to identify forward-looking statements.

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets; and
- the number of wells our oil and natural gas segment plans to drill during the year.

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 six 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 $449,000 per month ($5.4 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $267,000 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 $277,000 per month ($3.3 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 June 30, 2013, the following cash flow hedges were outstanding:

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

At June 30, 2013, the following non-designated hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'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 – Dec'14	Crude oil – collar	2,000 Bbl/day	$90.00-95.00	WTI – NYMEX
Jul'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)

After June 30, 2013, we entered into the following non-designated hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan’14 – Dec’14	Crude oil – collar	2,000 Bbl/day	$90.00-97.15	WTI – NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election, bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first six months of 2013, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $0.7 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 June 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 June 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.

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 June 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
April 1, 2013 to April 30, 2013	8,237	$ 44.47	8,237	—
May 1, 2013 to May 31, 2013	—	—	—	—
June 1, 2013 to June 30, 2013	88	44.47	88	—
Total	8,325	$ 44.47	8,325	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the second 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.

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.

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: August 6, 2013	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: August 6, 2013	By: /s/ David T. Merrill DAVID T. MERRILL Senior Vice President, Chief Financial Officer, and Treasurer

Exhibit 15

August 6, 2013

Securities and Exchange Commission
100 F. Street, N.W.
Washington, D.C. 20549

Commissioners:

We are aware that our report dated August 6, 2013 on our review of interim financial information of Unit Corporation for the three and six month periods ended June 30, 2013 and 2012 and included in the Company's quarterly report on Form 10-Q for the quarter ended June 30, 2013 is incorporated by reference in its Registration Statements on Form S-3 (File No. 333-173884-02); Form S-4 (File No. 333-184917); and Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166, 333-39584, 333-135194, 333-137857, 333-166605 and 333-181922).

Very truly yours,

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Tulsa, Oklahoma

<u>Exhibit 31.1</u>
302 CERTIFICATIONS

I, Larry D. Pinkston, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2013

<u>/s/ Larry D. Pinkston</u>
LARRY D. PINKSTON
Chief Executive Officer
and Director

Exhibit 31.2
302 CERTIFICATIONS

I, David T. Merrill, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2013

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

Exhibit 32

CERTIFICATION
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(SUBSECTIONS (A) AND (B) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Unit Corporation a Delaware corporation (the "Company"), does hereby certify, to such officer's knowledge, that:

The Quarterly Report on Form 10-Q for the quarter ended June 30, 2013 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of June 30, 2013 and December 31, 2012 and for the three and six month periods ended June 30, 2013 and 2012.

Dated: August 6, 2013

By: /s/ Larry D. Pinkston

Larry D. Pinkston
Chief Executive Officer and
Director

Dated: August 6, 2013

By: /s/ David T. Merrill

David T. Merrill
Senior Vice President, Chief Financial Officer, and
Treasurer

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-Q or as a separate disclosure document.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Unit Corporation and will be retained by Unit Corporation and furnished to the Securities and Exchange Commission or its staff on request.