UNIT CORP
Form 10-Q
August 04, 2011
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2011

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, 2011, 48,160,366 shares of the issuer s common stock were outstanding.

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UNIT CORPORATION

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Forward-Looking Statements

This document contains forward-looking statements meaning, statements related to future, not past, events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document which 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 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;
- production of oil, NGLs and natural gas;
- 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; and
- our ability to timely secure third party services used in completing our wells.

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

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

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2011	December 31, 2010
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,223	$ 1,359
Accounts receivable, net of allowance for doubtful accounts of $5,083 both at June 30, 2011 and at December 31, 2010	139,116	130,142
Materials and supplies	6,772	6,316
Current derivative assets (Note 10)	5,402	5,568
Current income tax receivable	19,203	25,211
Current deferred tax asset	11,773	13,537
Prepaid expenses and other	6,342	6,047
Total current assets	189,831	188,180
Property and equipment:		
Drilling equipment	1,353,142	1,273,861
Oil and natural gas properties on the full cost method:		
Proved properties	2,973,505	2,738,093
Undeveloped leasehold not being amortized	184,084	175,065
Gas gathering and processing equipment	236,369	199,564
Transportation equipment	33,508	31,688
Other	32,180	28,511
	4,812,788	4,446,782
Less accumulated depreciation, depletion, amortization and impairment	2,172,066	2,047,031
Net property and equipment	2,640,722	2,399,751
Deferred financing costs, net	5,913	0
Goodwill	62,808	62,808
Other intangible assets, net	2,460	3,022
Non-current derivative assets (Note 10)	3,028	2,537
Other assets	12,740	12,942
Total assets	$ 2,917,502	$ 2,669,240

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	June 30, 2011	December 31, 2010
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 88,637	$ 89,885
Accrued liabilities (Note 5)	35,259	30,093
Contract advances	1,803	2,582
Current portion of derivative liabilities (Note 10)	10,314	14,446
Current portion of other long-term liabilities (Note 6)	10,120	10,122
Total current liabilities	146,133	147,128
Long-term debt (Note 6)	250,000	163,000
Long-term derivative liabilities (Note 10)	1,718	4,359
Other long-term liabilities (Note 6)	92,917	88,030
Deferred income taxes	613,476	556,106
Shareholders equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $.20 par value, 175,000,000 shares authorized, 48,159,720 and 47,910,431 shares issued, respectively	9,530	9,493
Capital in excess of par value	401,571	393,501
Accumulated other comprehensive loss	(3,163)	(6,851)
Retained earnings	1,405,320	1,314,474
Total shareholders equity	1,813,258	1,710,617
Total liabilities and shareholders equity	$ 2,917,502	$ 2,669,240

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 115,183	$ 72,061	$ 213,171	$ 132,915
Oil and natural gas	131,662	91,136	241,496	190,189
Gas gathering and processing	44,368	36,344	84,132	77,479
Other income, net	282	5,062	101	10,570
Total revenues	291,495	204,603	538,900	411,153
Expenses:				
Contract drilling:				
Operating costs	64,238	46,541	117,082	87,441
Depreciation	19,218	16,445	36,515	30,231
Oil and natural gas:				
Operating costs	33,417	23,817	64,198	48,851
Depreciation, depletion and amortization	44,550	26,319	84,818	51,655
Gas gathering and processing:				
Operating costs	36,789	28,938	65,844	61,664
Depreciation and amortization	3,837	3,982	7,610	7,923
General and administrative	7,496	6,456	14,388	12,735
Interest, net	673	0	727	0
Total operating expenses	210,218	152,498	391,182	300,500
Income before income taxes	81,277	52,105	147,718	110,653
Income tax expense:				
Current	0	3,825	0	6,065
Deferred	31,458	16,105	56,872	36,260
Total income taxes	31,458	19,930	56,872	42,325
Net income	$ 49,819	$ 32,175	$ 90,846	$ 68,328
Net income per common share:				
Basic	$ 1.05	$ 0.68	$ 1.91	$ 1.45
Diluted	$ 1.04	$ 0.68	$ 1.89	$ 1.43

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30,	
	2011	2010
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 90,846	$ 68,328
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	129,475	90,304
Unrealized gain on derivatives	(1,147)	(1,453)
Deferred tax expense	56,872	36,260
Gain on disposition of assets	(158)	(10,418)
Stock compensation plans	7,026	7,476
Other	1,812	1,317
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(11,407)	(17,787)
Accounts payable	(26,124)	2,046
Material and supplies inventory	(456)	(1)
Accrued liabilities	6,072	(2,650)
Contract advances	(779)	(353)
Other - net	7,478	4,698
Net cash provided by operating activities	259,510	177,767
INVESTING ACTIVITIES:		
Capital expenditures	(343,755)	(217,544)
Producing property and other acquisitions	(9,791)	(94,030)
Proceeds from disposition of assets	1,604	33,985
Other - net	0	324
Net cash used in investing activities	(351,942)	(277,265)
FINANCING ACTIVITIES:		
Borrowings under line of credit	164,500	166,400
Payments under line of credit	(327,500)	(66,400)
Proceeds from issuance of senior subordinated notes, net of offering costs	244,035	0
Proceeds from exercise of stock options	644	119
Book overdrafts	10,617	0
Net cash provided by financing activities	92,296	100,119
Net increase (decrease) in cash and cash equivalents	(136)	621
Cash and cash equivalents, beginning of period	1,359	1,140
Cash and cash equivalents, end of period	$ 1,223	$ 1,761

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Net income	$ 49,819	$ 32,175	$ 90,846	$ 68,328
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $10,371, $1,360, $1,187 and $16,027	16,796	2,194	1,968	25,866
Reclassification - derivative settlements, net of tax of $1,906, ($6,048), $1,779 and ($8,062)	3,045	(9,764)	2,840	(13,016)
Ineffective portion of derivatives, net of tax of $(1,432), $253, ($702) and ($164)	(2,299)	409	(1,120)	(265)
Comprehensive income	$ 67,361	$ 25,014	$ 94,534	$ 80,913

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO THE 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 and us 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 along with the audited consolidated financial statements and notes included in our Form 10-K, filed February 24, 2011, for the year ended December 31, 2010.

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, 2011 and December 31, 2010;

Statements of Income for the three and six months ended June 30, 2011 and 2010;

Cash Flows for the six months ended June 30, 2011 and 2010; and

Statements of Comprehensive Income for the three and six months ended June 30, 2011 and 2010.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three and six months ended June 30, 2011 and 2010 are not necessarily indicative of the results to be realized for the full year in the case of 2011, or that we realized for the full year of 2010.

With respect to the unaudited financial information for the three and six month periods ended June 30, 2011 and 2010, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated August 4, 2011, 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.

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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 of those properties 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 based on the unescalated 12-month average price on our oil, natural gas liquids (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 unamortized cost of the amortized oil and natural gas properties exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

At June 30, 2011, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down. However, if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods. Our qualifying cash flow hedges used in the ceiling test determination at June 30, 2011, consisted of swaps covering 3.3 MMBoe in 2011, 4.4 MMBoe in 2012 and 0.7 MMBoe in 2013. The effect of those hedges on the June 30, 2011 ceiling test was a $37.1 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 10 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 3 ACQUISITIONS

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post closing adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition from unaffiliated parties consisting of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

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NOTE 4 EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended June 30, 2011:			
Basic earnings per common share	$ 49,819	47,655	$ 1.05
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	0	328	(0.01)
Diluted earnings per common share	$ 49,819	47,983	$ 1.04
For the three months ended June 30, 2010:			
Basic earnings per common share	$ 32,175	47,171	$ 0.68
Effect of dilutive stock options, restricted stock and SARs	0	485	0.00
Diluted earnings per common share	$ 32,175	47,656	$ 0.68

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,	
	2011	2010
Stock options and SARs	49,000	233,401
Average Exercise Price	$ 67.83	$ 53.12

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	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the six months ended June 30, 2011:			
Basic earnings per common share	$ 90,846	47,620	$ 1.91
Effect of dilutive stock options, restricted stock and SARs	0	324	(0.02)
Diluted earnings per common share	$ 90,846	47,944	$ 1.89
For the six months ended June 30, 2010:			
Basic earnings per common share	$ 68,328	47,146	$ 1.45
Effect of dilutive stock options, restricted stock and SARs	0	525	(0.02)
Diluted earnings per common share	$ 68,328	47,671	$ 1.43

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:

	Six Months Ended June 30,	
	2011	2010
Stock options and SARs	73,500	132,165
Average Exercise Price	$ 64.43	$ 59.87

NOTE 5 ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	June 30, 2011	December 31, 2010
	(In thousands)	
Employee costs	$ 14,212	$ 16,499
Lease operating expense accrual	7,082	6,214
Taxes	6,268	1,310
Interest	2,723	667
Hedge settlements	1,625	1,634
Other	3,349	3,769
Total accrued liabilities	$ 35,259	$ 30,093

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NOTE 6 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, 2011	December 31, 2010
	(In thousands)	
Revolving credit facility with average interest rates, including the effect of hedging, of 3.5% at December 31, 2010	$ 0	$ 163,000
6.625% senior subordinated notes due 2021	250,000	0
Total long-term debt	$ 250,000	$ 163,000

Credit Facility. Our credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we from time to time elect. As of June 30, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement.

The lenders aggregate commitment is limited to the lesser of the amount of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the credit facility) of our mid-stream segment. The current borrowing base, which is based on the April 1, 2011 redetermination, is $532.5 million. We or the lenders may request a onetime special redetermination of the amount 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 facility.

At our election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable period 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 period, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. On May 18, 2011, we used the proceeds of the notes offering discussed below to repay the then outstanding borrowings. At June 30, 2011, we did not have any outstanding borrowings under our credit facility.

The credit facility prohibits:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% 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.

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

- consolidated net worth of at least $900 million;
- a current ratio (as defined in the credit facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

As of June 30, 2011, we were in compliance with our credit facility s covenants.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of our 6.625% Senior Subordinated Notes due 2021 (the Notes). The 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 deferred financing costs over the life of the Notes. We used the net proceeds to repay outstanding borrowings under our credit facility, which was $220.3 million on May 18, 2011. The remaining proceeds will be used for general working capital purposes.

The Notes are guaranteed by our wholly-owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several. 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 were issued under an Indenture dated as of May 18, 2011, between us and Wilmington Trust FSB, as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors and the Trustee, establishing the terms and providing for the issuance of the Notes (the Supplemental Indenture). The discussion of the Notes in this report is qualified by and subject to the actual terms of the Indenture and the First Supplemental Indenture.

The Notes bear interest at a rate of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year, beginning on November 15, 2011), and will mature on May 15, 2021.

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 and the Supplemental Indenture contain customary events of default. The Indenture governing the Notes 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, 2011.

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Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	June 30, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligations (ARO)	$ 73,222	$ 69,265
Workers compensation	17,703	17,566
Separation benefit plans	6,244	5,690
Gas balancing	3,263	3,263
Deferred compensation plan	2,605	2,368
	103,037	98,152
Less current portion	10,120	10,122
Total other long-term liabilities	$ 92,917	$ 88,030

The estimated annual payments due under the terms of our other long-term liabilities during each of the five successive twelve month periods beginning July 1, 2011 (and through 2016) are $10.1 million, $15.3 million, $3.4 million, $2.7 million and $2.0 million, respectively.

NOTE 7 ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets (AROs). 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,	
	2011	2010
	(In thousands)	
ARO liability, January 1:	$ 69,265	$ 56,404
Accretion of discount	1,735	1,393
Liability incurred	2,879	1,402
Liability settled	(666)	(442)
Revision of estimates	9	91
ARO liability, June 30:	73,222	58,848
Less current portion	1,781	1,760
Total long-term ARO liability	$ 71,441	$ 57,088

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NOTE 8 NEW ACCOUNTING PRONOUNCEMENTS

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). In May 2011, the FASB issued ASU 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS.* ASU 2011-4 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the Board s intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The update is effective for annual periods beginning after December 15, 2011. We are in the process of evaluating the impact, if any, the adoption of this update will have on our financial statements.

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05 *Presentation of Comprehensive Income.* This ASU amends the Codification to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders equity. The amendments to the Codification in the ASU do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income.

ASU 2011-05 should be applied retrospectively. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We are in the process of evaluating the option we will choose to present comprehensive income and the impact it will have on our financial statements.

NOTE 9 STOCK-BASED COMPENSATION

For the three and six months ended June 30, 2011, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.7 million and $5.0 million, respectively. We also capitalized for the same periods 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 $1.0 million and $1.9 million, respectively. For the three and six months ended June 30, 2010, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $3.0 million and $5.5 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.8 million and $1.3 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.2 million and $2.1 million, respectively. The remaining unrecognized compensation cost related to unvested awards at June 30, 2011 is approximately $13.9 million of which $2.6 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 years.

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We did not grant any SARs or stock options (other than the non-employee director options discussed below) during either of the three or six month periods ending June 30, 2011 and 2010.

The table below shows the estimates of the fair value of these stock options granted to our non-employee directors under the Unit Corporation 2000 Non-employee Directors Stock Option Plan during the periods using the Black-Scholes model and applying the estimated values also presented in the table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Options granted [1]	31,500	52,504	31,500	52,504
Estimated fair value (in millions)	$ 0.7	$ 0.8	$ 0.7	$ 0.8
Estimate of stock volatility	0.48	0.45	0.48	0.45
Estimated dividend yield	0%	0%	0%	0%
Risk free interest rate	2%	2%	2%	2%
Expected annual life based on prior experience	5	5	5	5
Forfeiture rate	0%	0%	0%	0%

(1) On May 29, 2009, eight of our directors were each issued 3,063 options contingent on shareholder approval, which was received at the May 5, 2010 annual shareholder s meeting. These 24,504 options granted and vested simultaneously with that approval.

Expected volatilities are based on the historical volatility of our stock. Within the model, we use historical data to estimate stock option exercise and termination rates and aggregates groups that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the LIBOR rate using the term over which it is anticipated the grant will be exercised. The stock options granted in the second quarter of 2011 increased stock compensation expense for the second quarter and first six months of 2011 by $0.2 million.

The following table shows the fair value of the restricted stock awards granted to employees during the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Shares granted	4,167	0	196,748	248,383
Estimated fair value (in millions)	$ 0.2	$ 0	$ 10.3	$ 10.6
Percentage of shares granted expected to be distributed	95%	0%	93%	93%

The restricted stock awards granted during the first three and six months of 2011 will be recognized over a two and three year vesting period except for certain designated executive officers. For grants to those executive officers covering 66,869 shares of the total granted, 70% will vest in equal one-third annual increments, the other 30% of the shares awarded will cliff vest in the first quarter of 2014 subject to certain performance criteria, in which case, depending on these results, fewer or more shares might actually vest. These awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first six months of 2011 by an aggregate of $2.0 million.

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NOTE 10 DERIVATIVES

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit facility. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. In May 2011, in association with the repayment of outstanding borrowings under our credit facility, we terminated our two outstanding interest rate swaps that were previously accounted for as cash flow hedges, resulting in an increase of approximately $1.5 million in interest expense. Approximately $1.1 million of that expense was capitalized and will be amortized over the life of the assets.

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, 2011, 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.

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

Oil and Natural Gas Segment:

At June 30, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul 11 Dec 11	Crude oil swap	4,000 Bbl/day	$84.28	WTI NYMEX
Jan 12 Dec 12	Crude oil swap	4,500 Bbl/day	$95.91	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	2,000 Bbl/day	$102.05	WTI NYMEX
Jul 11 Dec 11	Natural gas swap	10,000 MMBtu/day	$4.43	CEGT
Jul 11 Dec 11	Natural gas swap	70,000 MMBtu/day	$4.87	IF NYMEX (HH)
Jul 11 Dec 11	Natural gas basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 NYMEX
Jan 12 Dec 12	Natural gas swap	30,000 MMBtu/day	$5.05	IF NYMEX (HH)
Jan 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Jul 11 Dec 11	Liquids swap (1)	644,406 Gal/mo	$0.97	OPIS Conway

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and normal butane.

At June 30, 2011, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jul 11 Dec 11		15,000 MMBtu/day	($0.14)	Tenn Zone 0 NYMEX

		Natural gas basis differential swap				
Jul 11	Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.21)	CEGT	NYMEX
Jul 11	Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.23)	PEPL	NYMEX

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The following tables present the fair values and locations of the derivative transactions recorded in our balance sheets:

	Balance Sheet Location	Derivative Assets Fair Value June 30, 2011	Derivative Assets Fair Value December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 5,402	$ 5,091
Long-term	Non-current derivative assets	3,028	2,537
Total derivatives designated as hedging instruments		8,430	7,628
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	0	477
Total derivatives not designated as hedging instruments		0	477
Total derivative assets		$ 8,430	$ 8,105

	Balance Sheet Location	Derivative Liabilities Fair Value June 30, 2011	Derivative Liabilities Fair Value December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 0	$ 1,139
Long-term	Long-term derivative liabilities	0	475
Commodity derivatives:			
Current	Current portion of derivative liabilities	9,975	13,166
Long-term	Long-term derivative liabilities	1,718	3,884
Total derivatives designated as hedging instruments		11,693	18,664
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	339	141
Total derivatives not designated as hedging instruments		339	141
Total derivative liabilities		$ 12,032	$ 18,805

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our balance sheets.

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of June 30, 2011 and 2010, we had a loss of $3.2 million and a gain of $17.0 million, net of tax, respectively, in accumulated OCI.

Based on market prices at June 30, 2011, we expect to transfer a loss of approximately $3.2 million, net of tax, included in accumulated OCI during the next 12 months in the related month of settlement. The commodity derivative instruments existing as of June 30, 2011 are expected to mature by December 2013.

Certain derivatives do not qualify as cash flow hedges. Currently, three of our basis swaps do not qualify as cash flow hedges. For these derivatives, changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported in oil and natural gas revenues in our unaudited condensed consolidated statements of income. Changes in the fair value of derivative instruments 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. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

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Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (cash flow hedges) for the six months ended June 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) [1]	
	2011	2010
	(In thousands)	
Interest rate swaps	$ 0	$ (1,217)
Commodity derivatives	(3,163)	18,260
Total	$ (3,163)	$ 17,043

(1) Net of taxes.

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (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 or (Loss) Recognized in Income [2]	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ (3,520)	$ 16,114	$ 3,731	$ (662)
Interest rate swaps	Interest, net	(1,431)	(302)	0	0
Total		$ (4,951)	$ 15,812	$ 3,731	$ (662)

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

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (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 or (Loss) Recognized in Income on Derivative	
		2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (346)	$ 967
Total		$ (346)	$ 967

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (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 or (Loss) Reclassified from Accumulated OCI into Income [1]		Amount of Gain or (Loss) Recognized in Income [2]	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ (2,885)	$ 21,687	$ 1,822	$ 429
Interest rate swaps	Interest, net	(1,734)	(609)	0	0
Total		$ (4,619)	$ 21,078	$ 1,822	$ 429

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

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Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (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 or (Loss) Recognized in Income on Derivative	
		2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (947)	$ 1,024
Total		$ (947)	$ 1,024

NOTE 11 FAIR VALUE MEASUREMENTS

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

Level 1 - unadjusted quoted prices in active markets for identical assets and liabilities.
Level 2 - significant observable pricing inputs other than quoted prices included within level 1 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.

The following tables set forth our recurring fair value measurements:

	June 30, 2011		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives	$ (15,351)	$ 11,749	$ (3,602)

	December 31, 2010		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Interest rate swaps	$ 0	$ (1,614)	$ (1,614)
Commodity derivatives	$ (19,954)	$ 10,868	$ (9,086)

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 swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

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Level 3 Fair Value Measurements

Interest Rate Swaps. The fair values of our interest rate swaps are based on estimates provided by our respective counterparties and reviewed internally against established index prices and other sources.

Commodity Derivatives. The fair values of our natural gas, natural gas liquids and basis swaps 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 reconcile our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended June 30, 2011		For the Six Months Ended June 30, 2011	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$ (1,361)	$ 9,368	$ (1,614)	$ 10,868
Total gains or (losses) (realized and unrealized):				
Included in earnings [(1)]	(1,431)	3,572	(1,734)	7,877
Included in other comprehensive income	1,361	1,847	1,614	82
Settlements	1,431	(3,038)	1,734	(7,078)
End of period	$ 0	$ 11,749	$ 0	$ 11,749
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at end of period	$ 0	$ 534	$ 0	$ 799

(1) Interest rate swaps and commodity swaps are reported in the unaudited condensed consolidated statements of income in interest, net and revenues, respectively.

	Net Derivatives			
	For the Three Months Ended June 30, 2010		For the Six Months Ended June 30, 2010	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (2,019)	$ 51,439	$ (1,948)	$ 19,948
Total gains or (losses) (realized and unrealized):				
Included in earnings [(1)]	(302)	18,690	(609)	27,764
Included in other comprehensive income (loss)	48	(18,431)	(23)	11,912
Purchases, issuance and settlements	302	(18,385)	609	(26,311)
End of period	$ (1,971)	$ 33,313	$ (1,971)	$ 33,313
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at end of period	$ 0	$ 305	$ 0	$ 1,453

(1) Interest rate swaps and commodity swaps and collars are reported in the unaudited condensed consolidated statements of income in interest, net and revenues, respectively.

Based on our valuation at June 30, 2011, we determined that the non-performance risk with regard to our counterparties was immaterial.

Fair Value of Other Financial Instruments

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

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At June 30, 2011, the carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Historically, based on the borrowing rates currently available to us for credit facility debt with similar terms and maturities and consideration of our non-performance risk, long-term debt associated with our credit facility has approximated its fair value. At June 30, 2011, we did not have any outstanding borrowings under our credit facility.

The carrying amount of long-term debt associated with the Notes reported in the consolidated balance sheet as of June 30, 2011 was $250.0 million. We estimate the fair value of these Notes using quoted marked prices at June 30, 2011 was $251.3 million.

NOTE 12 INDUSTRY SEGMENT INFORMATION

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

Contract drilling,
Oil and natural gas and
Mid-stream

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

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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 natural gas 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,	
	2011	2010	2011	2010
	(In thousands)			
Revenues:				
Contract drilling	$ 129,281	$ 82,046	$ 241,789	$ 149,547
Elimination of inter-segment revenue	(14,098)	(9,985)	(28,618)	(16,632)
Contract drilling net of inter-segment revenue	115,183	72,061	213,171	132,915
Oil and natural gas	131,662	91,136	241,496	190,189
Gas gathering and processing	63,894	47,008	120,902	100,742
Elimination of inter-segment revenue	(19,526)	(10,664)	(36,770)	(23,263)
Gas gathering and processing net of inter-segment revenue	44,368	36,344	84,132	77,479
Other	282	5,062	101	10,570
Total revenues	$ 291,495	$ 204,603	$ 538,900	$ 411,153
Operating income:				
Contract drilling	$ 31,727	$ 9,075	$ 59,574	$ 15,243
Oil and natural gas	53,695	41,000	92,480	89,683
Gas gathering and processing	3,742	3,424	10,678	7,892
Total operating income [(1)]	89,164	53,499	162,732	112,818
General and administrative expense	(7,496)	(6,456)	(14,388)	(12,735)
Interest expense, net	(673)	0	(727)	0
Other income, net	282	5,062	101	10,570
Income before income taxes	$ 81,277	$ 52,105	$ 147,718	$ 110,653

(1) Operating income is total operating revenues less operating expenses, depreciation, depletion and amortization and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

Unit Corporation

We have reviewed the accompanying unaudited condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of June 30, 2011, and the related unaudited condensed consolidated statements of income and comprehensive income for the three and six-month periods ended June 30, 2011 and 2010 and the unaudited condensed consolidated statements of cash flows for the six-month periods ended June 30, 2011 and 2010. 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 unaudited condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2010, and the related consolidated statements of income, shareholders equity and of cash flows for the year then ended (not presented herein), and in our report dated February 24, 2011, 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, 2010, 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 4, 2011

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

Management s Discussion and Analysis (MD&A) provides an understanding of our operating results and financial condition by focusing on changes in certain key measures 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
- 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:

- *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.
- *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.
- *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, natural gas liquids and oil production; the demand for oil 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.

In developing our initial overall operating budget for 2011, we used average oil and natural gas prices of $82.00 per Bbl and $4.60 per Mcf. Our 2011 operating budget will be funded using internally generated cash flow, borrowings under our credit facility and the remaining proceeds from the Notes.

Executive Summary

Contract Drilling

The rate at which our drilling rigs were used (our utilization rate) for the second quarter 2011 was 60%, compared to 58% and 47% for the first quarter of 2011 and the second quarter of 2010, respectively.

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Dayrates for the second quarter of 2011 averaged $18,861, an increase of 7% from the first quarter of 2011 and an increase of 26% from the second quarter of 2010. These increases were primarily the result of increased use of drilling rigs in the 1,000 to 1,500 horsepower range that are used for horizontal drilling and also provide for higher rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the second quarter of 2011 increased 13% over the first quarter of 2011 and 100% over the second quarter of 2010. The increases were primarily due to increases in dayrates and utilization over the comparative periods as discussed above.

Operating cost per day for the second quarter of 2011 increased 14% over the first quarter of 2011 and increased 9% over the second quarter of 2010. The increase over the first quarter 2011 and the second quarter of 2010 is primarily due to increases in direct expenses due to pay increases for rig personnel and to a lesser extent from increases in rig servicing costs.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. With the current weakened natural gas market, operators are focusing on drilling for oil and NGLs. Approximately 79% of our drilling rigs working today are drilling for oil or NGLs. Of those, approximately 96% are drilling horizontal or directional wells.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. Three of these drilling rigs are now completed and are working in the Bakken shale. The remaining two drilling rigs are expected to be completed late in the third quarter of 2011. Each of these five new drilling rigs will initially be working under a two-year drilling contract. We have recently been awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. Delivery of the two rigs is scheduled for the fourth quarter of 2011. Both drilling rigs will be for our Rocky Mountain division operations. On completion of the additional drilling rigs, we will have 128 drilling rigs in our fleet.

Our anticipated 2011 capital expenditures for this segment are $174.0 million.

As of June 30, 2011, we had 43 long-term drilling contracts with original terms ranging from six months to three years. Twenty-eight of these contracts are up for renewal in 2011 and 15 are up for renewal in 2012 and later. These contracts include two of the seven term contracts for the new drilling rigs discussed above. Of the 28 contracts renewing in 2011; 16 renew during the third quarter and 12 during the fourth quarter. 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.

Oil and Natural Gas

During the second quarter of 2010 we completed an acquisition of oil and natural gas properties from certain unaffiliated parties. The properties were purchased for approximately $73.7 million in cash. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. Proved developed producing net reserves associated with the 10 acquired producing wells is approximately 762,000 barrels of oil equivalent consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Second quarter 2011 production was 2,983,000 barrels of oil equivalent (Boe) per day, a 9% increase over the first quarter of 2011 and a 28% increase over the second quarter of 2010. The increase in production came primarily from oil and NGL rich prospects where we completed and brought new wells online and, to a lesser extent, from production associated with the acquisition discussed above. Second quarter 2011 oil and NGL production was 39% of our total production compared to 30% of our total production over the second quarter of 2010. Our production in 2010 was hindered by delays in securing third party fracture stimulation services and delays associated with connecting wells to gathering systems. In addition, our 2010 production was curtailed because of the unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production.

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Second quarter 2011 oil and natural gas revenues increased 20% over the first quarter of 2011 and increased 44% over the second quarter of 2010. These increases were primarily due to increased production and increased oil and liquid prices over the comparative periods.

Our oil and NGL prices for the second quarter of 2011 increased 6% and 15%, respectively, over the first quarter of 2011 and 34% and 36%, respectively, over the second quarter of 2010. Natural gas prices for the second quarter of 2011 remained unchanged compared to first quarter 2011 and decreased 23% compared to the second quarter of 2010.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 24% over the first quarter of 2011 and increased 46% over the second quarter of 2010. The increases were primarily attributable to increased production and increases in oil and NGL prices partially offset by increases in lease operating expenses and gross production taxes.

Operating cost per Boe produced for the second quarter of 2011 remained unchanged over the first quarter of 2011 and increased 9% over the second quarter of 2010. The increases were primarily due to the increase in lease operating expense (LOE) due to increased workover expense and higher saltwater disposal fees and higher gross production taxes due to higher oil prices and revenue from increased production between quarters. Production taxes increased due to commodity price increases between the periods and increased oil and NGL production.

For 2011, we currently have hedged approximately 62% of our anticipated daily oil production, approximately 60% of our anticipated natural gas production and approximately 8% of our anticipated natural gas liquids production (percentages based on our second quarter 2011 production).

Currently for 2012 we have hedged 4,500 Bbls per day of oil production and 45,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $95.91 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.33. The average basis differential for the applicable swaps is ($0.28).

Currently for 2013 we have hedged 2,000 Bbls per day of oil production. The oil production is hedged under swap contracts at an average price of $102.05 per barrel.

During the first six months of 2011, we drilled 79 gross wells (37.49 net wells). We are increasing our estimated capital expenditures for 2011 from $415.0 million to $435.0 million with the increase primarily being associated with the purchase of acreage both within our existing core plays and in areas outside of our core plays. For the year, we continue to plan to drill 180 gross wells; however, we are increasing our anticipated annual production guidance to 11.3 to 11.6 MMBoe from our previous guidance of 11.0 to 11.3 MMBoe, due primarily to favorable results associated with our activity during the first half of 2011.

Subsequent to June 30, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, subject to post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper and Ellis Counties in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. The acquisition also included in excess of 12,000 net held by production acres in the area for future development.

Also subsequent to June 30, 2011, we entered into a Purchase and Sale Agreement to acquire certain producing properties for $30.5 million in cash, subject to closing adjustments, from an unaffiliated seller. The acquisition consists of more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The preliminary proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed, with current production of approximately 7.8 MMcfe per day. The acquisition also includes approximately 55,000 net acres of which 96% is held by production. The closing, subject to customary due diligence, is expected to occur before the end of the third quarter.

Mid-Stream

Second quarter 2011 liquids sold per day increased 9% over the first quarter of 2011 and increased 27% over the second quarter of 2010. The increases resulted from upgrades and expansions to existing plants and the connection of new wells. For the second quarter of 2011, gas processed per day increased 5% over the first quarter of 2011 and 10% over the second quarter of 2010. In 2010, we upgraded several of our existing processing facilities and added processing plants which was the primary reason for increased volumes. For the second quarter of 2011, gas gathered per day increased 3% over the first quarter of 2011 and increased 4% over the second quarter of 2010 primarily from the 52 well connects throughout 2010.

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NGL prices in the second quarter of 2011 increased 9% over the price received in the first quarter of 2011 and increased 31% over the price received in the second quarter of 2010. The price of liquids as compared to natural gas affects the revenue in our mid-stream operations and determines the fractionation spread which is the difference in the value received for the NGLs recovered from natural gas in comparison to the amount received for the equivalent MMBtu s of natural gas if unprocessed.

Direct profit (mid-stream revenues less mid-stream operating expense) for the second quarter of 2011 decreased 29% from the first quarter of 2011 and increased 2% over the second quarter of 2010. The decrease from first quarter of 2011 resulted primarily from the increased cost of gas purchased as the result of the expiration of some contracts. We had to renegotiate our contracts with producers supplying gas to one of our processing plants. The renegotiated contracts changed from percent of index to percent of proceeds (effective April 1, 2011) which resulted in lower direct profit. The increase over the second quarter of 2010 was due to increased production as limited by the increased cost of gas purchased.

Total operating cost for our mid-stream segment for the second quarter of 2011 increased 27% over both the first quarter of 2011 and the second quarter of 2010 due primarily to the increase in gas purchased due to increased volumes and prices.

During the fourth quarter of 2010, we completed the installation and start up of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. With the addition of this new processing plant, the total processing capacity at our Hemphill facility has increased to approximately 100.0 MMcf per day.

In our Mid-continent operations, we are in the process of installing a high-efficiency processing plant at our Cashion facility, located in Logan, Canadian, Oklahoma and Kingfisher Counties in Oklahoma, which has improved liquids recovery capability compared to our existing plant which it is replacing. In Grant County, Oklahoma, we have begun construction of a new gathering system, which will include a processing plant, and is anticipated to be completed during the third quarter of 2011.

In connection with our Appalachian operations, we are in the final stages of construction of a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day. We anticipate this pipeline will be operational during the third quarter of 2011. We have signed an agreement to transport gas on this system for an unaffiliated party. In addition to the Preston County pipeline, we recently signed a contract to build a gathering system and compressor station in Tioga and Potter Counties, Pennsylvania. This system will deliver gas to Dominion Transmission pipeline and is scheduled to be completed in the fourth quarter of this year or early in 2012. We recently signed a letter of intent with a third party to construct a pipeline in Allegheny and Butler Counties of Pennsylvania. Land and survey work associated with the first phase, which consists of a 7-mile, 16 pipeline, has begun and construction is anticipated to be completed during the first half of 2012.

Our anticipated capital expenditures for 2011 are $86.0 million.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and, when necessary, borrowings under our credit facility. The principal factors determining the amount of our cash flow are:

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

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The following is a summary of certain financial information as of June 30, 2011 and 2010 and for the six months ended June 30, 2011 and 2010:

	June 30, 2011	June 30, 2010	% Change
	(In thousands except percentages)		
Working capital	$ 43,698	$ 47,150	(7)%
Long-term debt	$ 250,000	$ 130,000	92%
Shareholders equity	$ 1,813,258	$ 1,656,173	9%
Ratio of long-term debt to total capitalization	12%	7%	71%
Net income	$ 90,846	$ 68,328	33%
Net cash provided by operating activities	$ 259,510	$ 177,767	46%
Net cash used in investing activities	$ (351,942)	$ (277,265)	27%
Net cash provided by financing activities	$ 92,296	$ 100,119	(8)%

The following table summarizes certain operating information:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	71.6	54.5	31%
Total number of drilling rigs owned at the end of the period	123	123	0%
Average dayrate	$ 18,304	$ 14,553	26%
Oil and Natural Gas:			
Oil production (MBbls)	1,147	623	84%
Natural gas liquids production (MBbls)	1,046	765	37%
Natural gas production (MMcf)	21,178	19,735	7%
Average oil price per barrel received	$ 87.14	$ 67.12	30%
Average oil price per barrel received excluding hedges	$ 96.06	$ 75.08	28%
Average NGL price per barrel received	$ 42.80	$ 38.01	13%
Average NGL price per barrel received excluding hedges	$ 43.72	$ 37.88	15%
Average natural gas price per mcf received	$ 4.29	$ 5.79	(26)%
Average natural gas price per mcf received excluding hedges	$ 3.91	$ 4.44	(12)%
Mid-Stream:			
Gas gathered MMBtu/day	188,340	181,998	3%
Gas processed MMBtu/day	88,603	79,623	11%
Gas liquids sold gallons/day	342,486	266,793	28%
Number of natural gas gathering systems	34	33	3%
Number of processing plants	10	8	25%

At June 30, 2011, we had unrestricted cash totaling $1.2 million and we did not have any borrowings outstanding of the $325.0 million we had elected to have currently available under our credit facility. Our credit facility is used for working capital and capital expenditures. We are in the process of renegotiating our credit facility to extend our maturity date past May 2012.

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

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Working Capital

Typically, our working capital balance fluctuates. This is because of the timing of our trade accounts receivable and accounts payable and from the fluctuation in current assets and liabilities associated with the mark to market value of our hedging activity. We had working capital of $43.7 million and $47.2 million as of June 30, 2011 and 2010, respectively. The effect of our hedging activity decreased working capital by $3.2 million as of June 30, 2011 and increased working capital by $15.5 million as of June 30, 2010.

Contract Drilling

Many factors influence the number of drilling rigs we are working at any one 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.

As activity has increased over last year s levels, competition to keep qualified labor has also increased. In the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all our divisions.

Over the past year, as more of our customers shift to drilling horizontal wells, demand for drilling rigs in the 1,000 to 1,500 horsepower range has increased as those drilling rigs have the horsepower ideally suited for horizontal drilling. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For the first six months of 2011, our average dayrate was $18,304 per day compared to $14,553 per day for the first six months of 2010. The average number of our drilling rigs used in the first six months of 2011 was 71.6 drilling rigs (59%) compared with 54.5 drilling rigs (43%) in the first six months of 2010. Based on the average utilization of our drilling rigs during the first six months of 2011, a $100 per day change in dayrates has a $7,160 per day ($2.6 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 the drilling services we perform on our properties 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 $28.6 million and $16.6 million for the six months of 2011 and 2010, respectively, from our contract drilling segment and eliminated the associated operating expense of $18.5 million and $14.8 million during the six months of 2011 and 2010, respectively, yielding $10.1 million and $1.8 million during the six months of 2011 and 2010, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Impact of Prices for Our Oil, NGLs and Natural Gas

Any significant change in oil or natural gas prices has a material effect on our revenues, cash flow and the value of our oil, liquids 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 2011 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 $335,000 per month ($4.0 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 2011 was $4.29 compared to $5.79 for the first six months of 2010. Based on our first six months of 2011 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $181,000 per month ($2.2 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $165,000 per month ($2.0 million annualized) change in our pre-tax operating cash flow. In the first six months of 2011, our average oil price per barrel received, including the effect of hedging, was $87.14 compared with an average oil

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price, including the effect of hedging, of $67.12 in the first six months of 2010 and our first six months of 2011 average NGLs price per barrel received was $42.80 compared with an average NGL price per barrel of $38.01 in the first six months of 2010.

Because commodity prices have an effect on 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. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our credit facility since that determination is based mainly on the value of our oil, NGLs and natural gas reserves. A reduction could limit our ability to carry out our planned capital projects.

Our natural gas production is sold to intrastate and interstate pipelines, 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.

Mid-Stream Operations

This segment is engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, 10 processing plants, 34 gathering systems and 870 miles of pipeline. Our operations are located in Oklahoma, Texas, Kansas, Pennsylvania and West Virginia. This segment enhances our ability to gather and market not only our own natural gas 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 2011 and 2010, this segment purchased $34.6 million and $21.2 million, respectively, of our oil and natural gas segment s production and provided gathering and transportation services to our oil and natural gas segment of $2.2 million and $2.1 million, respectively. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment have been eliminated in our unaudited condensed consolidated financial statements.

Our mid-stream segment gathered an average of 188,340 MMBtu per day in the first six months of 2011 compared to 181,998 MMBtu per day in the first six months of 2010. Processed volumes were 88,603 MMBtu per day in the first six months of 2011 compared to 79,623 MMBtu per day in the first six months of 2010. The amount of NGLs we sold was 342,486 gallons per day in the first six months of 2011 compared to 266,793 gallons per day in the first six months of 2010. Gas gathering volumes per day in the first six months of 2011 increased 3% compared to the first six months of 2010 primarily from the 52 wells connected to our systems throughout 2010. Processed volumes increased 11% over the comparative six months and NGLs sold also increased 28% over the comparative period primarily due to the addition of wells connected, recent upgrades to several of our processing systems and the doubling in size of our Hemphill facility in the Texas Panhandle.

Our Credit Facility

In May 2011, we used proceeds from the Notes offering to repay $220.3 million in outstanding debt under our credit facility. We also terminated two $15.0 million interest rate swaps associated with that debt with a settlement cost to us of $1.5 million. At June 30, 2011, we did not have any borrowings under the credit facility.

Our credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we from time to time elect. As of June 30, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement.

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

Lender	Participation Interest
Bank of Oklahoma, N.A.	18.75%
Bank of America, N.A.	18.75%
BMO Capital Markets Financing, Inc.	18.75%
BBVA Compass Bank	17.50%
Comerica Bank	8.75%
BNP Paribas	8.75%
Crédit Agricole Corporate and Investment Bank	8.75%
	100.00%

The lenders aggregate commitment is limited to the lesser of the amount of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the credit facility) of our mid-stream segment. The current borrowing base, which is based on the April 1, 2011 redetermination, is $532.5 million. We or the lenders may request a onetime special redetermination of the amount 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 facility.

At our election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable period 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 period, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty.

The credit facility prohibits:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% 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 facility also requires that we have at the end of each quarter:

- consolidated net worth of at least $900 million;
- a current ratio (as defined in the credit facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

As of June 30, 2011, we were in compliance with our credit facility s covenants.

We are in the process of renegotiating our credit facility to extend our maturity date past May 2012.

6.625% Senior Subordinated Notes

During the second quarter of 2011, in an effort to extend the maturity profile of our outstanding indebtedness, we issued $250.0 million of 6.625% Senior Subordinated Notes due 2021. We used the net proceeds of approximately $244.0 million from the offering to repay outstanding debt under our revolving credit facility and the remaining amount will be used for general working capital purposes.

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Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. During the first half of 2010, we sold eight of our idle mechanical drilling rigs to an unaffiliated party. These drilling rigs ranged in horsepower from 800 to 1,000. Proceeds from this sale were $23.9 million resulting in a gain of $5.7 million which we recorded in the first quarter of 2010. The proceeds were used to refurbish and upgrade additional drilling rigs in our fleet allowing those drilling rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer.

In September 2010, we entered into a contract with an unaffiliated party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction was closed in October and resulted in a gain of $3.5 million.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. Three of these drilling rigs are now completed and are working in the Bakken shale. The remaining two drilling rigs are expected to be completed late in the third quarter of 2011. Each of these five new drilling rigs will initially be working under a two-year drilling contract. We have recently been awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. Delivery of the two rigs is scheduled for the fourth quarter of 2011. Both drilling rigs will be for our Rocky Mountain division operations. On completion of the additional drilling rigs, we will have 128 drilling rigs in our fleet.

Our anticipated 2011 capital expenditures for this segment have been revised from $143.0 million to $174.0 million. At June 30, 2011, we had commitments to purchase approximately $6.4 million for drill pipe, top drives and related equipment over the next twelve months. We have spent $85.0 million for capital expenditures during the first six months of 2011 compared to $62.8 million in the first six months of 2010.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Our 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 79 gross wells (37.49 net wells) in the first six months of 2011 compared to 66 gross wells (35.35 net wells) in the first six months of 2010. Total capital expenditures for the first six months of 2011 by this segment, excluding a $2.2 million ARO liability, and $9.8 million for acquisitions, totaled $232.5 million. Currently we plan to participate in drilling approximately 180 gross wells in 2011 and estimate our total capital expenditures (excluding acquisitions) for this segment are anticipated to be approximately $435.0 million, revised from $415.0 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.

In June 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties. The properties were purchased for approximately $73.7 million in cash, after post closing adjustments. After these adjustments, the acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition consisting of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million from an unaffiliated party.

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Subsequent to June 30, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, subject to post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper and Ellis Counties in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. The acquisition also included in excess of 12,000 net held by production acres in the area for future development.

Also subsequent to June 30, 2011, we entered into a Purchase and Sale Agreement to acquire certain producing properties for $30.5 million in cash, subject to closing adjustments, from an unaffiliated seller. The acquisition consists of more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The preliminary proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed, with current production of approximately 7.8 MMcfe per day. The acquisition also includes approximately 55,000 net acres of which 96% is held by production. The closing, subject to customary due diligence, is expected to occur before the end of the third quarter.

Mid-Stream Acquisitions and Capital Expenditures. During the fourth quarter of 2010, we completed the installation and start up of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. With the addition of this new processing plant, the total processing capacity at our Hemphill facility increased to approximately 100.0 MMcf per day.

In our Mid-continent operations, we are in the process of installing a high-efficiency processing plant at our Cashion facility, located in Logan, Canadian, Oklahoma and Kingfisher Counties in Oklahoma, which has improved liquids recovery capability compared to our existing plant which it is replacing. In Grant County, Oklahoma, we have begun construction of a new gathering system, which will include a processing plant, and is anticipated to be completed during the third quarter of 2011.

In connection with our Appalachian operations, we recently committed to build a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day. Construction began during the first quarter of 2011 with the facility anticipated to be operational during the third quarter of 2011. We have signed an agreement to transport gas on this system for an unaffiliated party. In addition to the Preston County pipeline, we recently signed a contract to build a gathering system and compressor station in Tioga and Potter Counties, Pennsylvania. This system will deliver gas to Dominion Transmission pipeline and is scheduled to be completed in the fourth quarter of this year or early in 2012. We recently signed a letter of intent with a third party to construct a pipeline in Allegheny and Butler Counties of Pennsylvania. Land and survey work associated with the first phase, which consists of a 7-mile, 16 pipeline, has begun and construction is anticipated to be completed during the first half of 2012.

During the first six months of 2011, our mid-stream segment incurred $36.8 million in capital expenditures as compared to $9.6 million in the first six months of 2010. For 2011, we have budgeted capital expenditures of approximately $86.0 million, revised from $47.0 million.

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Contractual Commitments

At June 30, 2011, 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)	$ 415,625	$ 16,563	$ 33,125	$ 33,125	$ 332,812
Operating leases (2)	5,018	1,600	2,642	776	0
Drill pipe, drilling components and equipment purchases (3)	6,423	6,423	0	0	0
Total contractual obligations	$ 427,066	$ 24,586	$ 35,767	$ 33,901	$ 332,812

(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 includes interest calculated using our interest rate of 6.625%.

(2) We lease office space or yards in Beaver, Elk City, Oklahoma City and Tulsa, Oklahoma; Canadian and Houston, Texas; Denver and Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2015. 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 purchase approximately $6.4 million of new drilling rig components, drill pipe, drill collars and related equipment over the next twelve months.

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At June 30, 2011, 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)	$ 2,605	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 6,244	$ 604	Unknown	Unknown	Unknown
Derivative liabilities commodity hedges	$ 12,032	$ 10,314	$ 1,718	$ 0	$ 0
Asset retirement liability (3)	$ 73,222	$ 1,781	$ 15,347	$ 3,527	$ 52,567
Gas balancing liability (4)	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ 0	Unknown	Unknown	Unknown	Unknown
Workers compensation liability (6)	$ 17,703	$ 7,735	$ 3,324	$ 1,170	$ 5,474

(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 with us 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. 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 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, with a subsidiary of ours serving as general partner. 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 $5,000 in 2011, $22,000 in 2010 and $1,000 in 2009.

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(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 facility as well as the prices to be received for a portion of our oil, NGLs and natural gas production.

Interest Rate Swaps. From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit facility. Under these transactions we swap the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest. In May 2011, in association with the repayment of outstanding borrowings under our credit facility, we terminated our two outstanding interest rate swaps that were previously accounted for as cash flow hedges, resulting in an increase of approximately $1.5 million in interest expense. Approximately $1.1 million of that expense was capitalized and will be amortized over the life of the assets.

These two interest rate swaps increased our interest expense by $1.4 million and $1.7 million for the three and six months ended June 2011 and by $0.3 million and $0.6 million for the three and six months ended June 2010.

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. Based on our second quarter 2011 average daily production, as of June 30, 2011, the approximated percentages of our production that we have hedged are as follows:

Oil and Natural Gas Segment:

	July December 2011	January December 2012	January December 2013
Daily oil production	62 %	69 %	31 %
Daily natural gas production	60 %	34 %	0 %
Natural gas liquids production	8 %	0 %	0 %

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 will not be able to meet their financial obligations under the transactions. Based on our evaluation at June 30, 2011, we determined that there was no material risk of non-performance by our counterparties. At June 30, 2011, 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, 2011 (In millions)
Bank of Montreal	$ 5.2
Bank of America, N.A.	0.1
Crédit Agricole Corporate and Investment Bank, London Branch	(7.4)
Comerica Bank	(2.1)
BBVA Compass Bank	(1.2)
Barclays Capital	(0.8)
ConocoPhillips	(0.3)
BNP Paribas	2.9
Total assets (liabilities)	$ (3.6)

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If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our consolidated balance sheets. At June 30, 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $5.4 million and $3.0 million, respectively, and current and non-current liabilities of $10.3 million and $1.7 million, respectively. At June 30, 2010, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $25.9 million and $4.5 million, respectively.

We recognize in accumulated OCI the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of June 30, 2011, we had a loss of $3.2 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at June 30, 2011, we expect to transfer to earnings a loss of approximately $3.2 million, net of tax, of the loss included in accumulated OCI during the next 12 months in the related month of production. The commodity derivative instruments existing as of June 30, 2011 are expected to mature by December 2013.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these types of derivatives, any changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of income as unrealized gains (losses) within our oil and natural gas revenues. Changes in the fair value of derivative instruments 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. Any change in fair value resulting from ineffectiveness is recognized currently in our oil and natural gas revenues as unrealized gains (losses). The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at June 30:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Oil and natural gas revenue:				
Realized gains (losses) on oil and natural gas derivatives	$ (3,610)	$ 16,114	$ (3,157)	$ 21,687
Unrealized gains (losses) on ineffectiveness of cash flow hedges	3,731	(662)	1,822	429
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(256)	967	(675)	1,024
Impact on pre-tax earnings	$ (135)	$ 16,419	$ (2,010)	$ 23,140

Stock and Incentive Compensation

During the first six months of 2011, we granted awards covering 196,748 shares of restricted stock. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $10.3 million. Compensation expense will be recognized over their two and three year vesting periods, and during the first six months of 2011, we recognized $1.6 million in additional compensation expense and capitalized $0.4 million for these awards. During the first six months of 2011, we recognized compensation expense of $5.0 million for all of our restricted stock, stock options and SAR grants and capitalized $1.3 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 to $1.0 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the 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.

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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 2011 and 2010, the total we received for all of these fees was $1.4 million and $1.0 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). In May 2011, the FASB issued ASU 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS.* ASU 2011-4 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the Board s intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The update is effective for annual periods beginning after December 15, 2011. We are in the process of evaluating the impact, if any, the adoption of this update will have on our financial statements.

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05 *Presentation of Comprehensive Income.* This ASU amends the Codification to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders equity. The amendments to the Codification in the ASU do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income.

ASU 2011-05 should be applied retrospectively. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We are in the process of evaluating the option we will choose to present comprehensive income and the impact it will have on our financial statements.

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Results of Operations

Quarter Ended June 30, 2011 versus Quarter Ended June 30, 2010

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

	Quarter Ended June 30,		Percent
	2011	2010	Change
Total revenue	$ 291,495,000	$ 204,603,000	42 %
Net income	$ 49,819,000	$ 32,175,000	55 %
Contract Drilling:			
Revenue	$ 115,183,000	$ 72,061,000	60 %
Operating costs excluding depreciation	$ 64,238,000	$ 46,541,000	38 %
Percentage of revenue from daywork contracts	100%	100%	0%
Average number of drilling rigs in use	73.1	58.1	26 %
Average dayrate on daywork contracts	$ 18,861	$ 14,915	26 %
Depreciation	$ 19,218,000	$ 16,445,000	17 %
Oil and Natural Gas:			
Revenue	$ 131,662,000	$ 91,136,000	44 %
Operating costs excluding depreciation, depletion and amortization	$ 33,417,000	$ 23,817,000	40 %
Average oil price (Bbl)	$ 89.77	$ 66.93	34 %
Average NGL price (Bbl)	$ 45.49	$ 33.37	36 %
Average natural gas price (Mcf)	$ 4.30	$ 5.62	(23)%
Oil production (Bbl)	591,000	321,000	84 %
NGL production (Bbl)	567,000	388,000	46 %
Natural gas production (Mcf)	10,946,000	9,701,000	13 %
Depreciation, depletion and amortization rate (Boe)	$ 14.82	$ 11.22	32 %
Depreciation, depletion and amortization	$ 44,550,000	$ 26,319,000	69 %
Mid-Stream Operations:			
Revenue	$ 44,368,000	$ 36,344,000	22 %
Operating costs excluding depreciation and amortization	$ 36,789,000	$ 28,938,000	27 %
Depreciation and amortization	$ 3,837,000	$ 3,982,000	(4)%
Gas gathered MMBtu/day	190,921	183,858	4%
Gas processed MMBtu/day	90,737	82,699	10 %
Gas liquids sold gallons/day	356,484	279,736	27 %
General and administrative expense	$ 7,496,000	$ 6,456,000	16 %
Interest expense, net	$ 673,000	$ 0	NM
Income tax expense	$ 31,458,000	$ 19,930,000	58 %
Average interest rate	7%	4.1%	71 %
Average long-term debt outstanding	$ 230,141,000	$ 71,197,000	NM

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

Contract Drilling

Drilling revenues increased $43.1 million or 60% in the second quarter of 2011 versus the second quarter of 2010 primarily due to a 26% increase in the average number of drilling rigs in use during the second quarter of 2011 compared to the second quarter of 2010 and a 26% higher average dayrate in the second quarter of 2011 compared to the second quarter of 2010. Average drilling rig utilization increased from 58.1 drilling rigs in the second quarter of 2010 to 73.1 drilling rigs in the second quarter of 2011. Oil prices improved in the second quarter of 2011 compared to the second quarter of 2010, creating increased demand for drilling rigs.

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Drilling operating costs increased $17.7 million or 38% between the comparative second quarters of 2011 and 2010 primarily due to increased utilization and increased direct cost due to higher personnel cost. Due to an increase in activity over last year s levels, competition to keep qualified labor has increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all divisions. Contract drilling depreciation increased $2.8 million or 17% primarily due to increased utilization and from capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $40.5 million or 44% in the second quarter of 2011 as compared to the second quarter of 2010 primarily due to an increase in equivalent production volumes of 28% and an increase in oil and NGL prices partially offset by decreases in prices for natural gas. Average oil and NGL prices between the comparative quarters increased 34% to $89.77 per barrel and 36% to $45.49 per barrel, respectively, and natural gas prices decreased 23% to $4.30 per Mcf. In the second quarter of 2011, as compared to the second quarter of 2010, oil production increased 84%, NGL production increased 46% and natural gas production increased 13%. Production for second quarter 2010 was negatively impacted by an unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production and production growth was hampered by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $9.6 million or 40% between the comparative second quarters of 2011 and 2010 due to higher gross production taxes due to higher oil and NGL prices and increased production between quarters. Lease operating expenses per Boe decreased 2% to $6.44.

Depreciation, depletion and amortization (DD&A) increased $18.2 million or 69% primarily due to a 32% increase in our DD&A rate and a 28% increase in equivalent production. The increase in our DD&A rate in the second quarter of 2011 compared to the second quarter of 2010 resulted primarily from increases throughout 2010 and the first six months of 2011 from increased net book value on new reserves added. 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.

Mid-Stream

Our mid-stream revenues were $8.0 million or 22% higher for the second quarter of 2011 as compared to the second quarter of 2010 primarily due to higher NGL and natural gas prices. The average price for NGLs sold increased 31% and the average price for natural gas sold increased 4%. Gas processing volumes per day increased 10% between the comparative quarters and NGLs sold per day increased 27% between the comparative quarters. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day increased due to both an increase in volumes processed, upgrades to several of our processing facilities and the doubling in size of our Hemphill facility in the Texas Panhandle. Gas gathering volumes per day increased 4% primarily from new well connections.

Operating costs increased $7.9 million or 27% in the second quarter of 2011 compared to the second quarter of 2010 primarily due to a 32% increase in prices paid for natural gas purchased. Depreciation and amortization decreased $0.1 million, or 4%, primarily due to decreased amortization on our intangible asset. For 2011, we anticipate an increase in well connections over 2010 due to anticipated drilling activity by operators in the areas of our existing gathering systems along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

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Other

Other revenue of $5.1 million for the second quarter of 2010 was primarily attributable to the sale of six mechanical drilling rigs.

General and administrative expenses increased $1.0 million or 16% in the second quarter of 2011 compared to the second quarter of 2010 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $0.7 million between the comparative second quarters of 2011 and 2010. 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 by 71% due to the Notes issued during the second quarter of 2011 and our average debt outstanding was $158.9 million higher in the second quarter of 2011 as compared to the second quarter of 2010 due to the drilling of developmental wells and construction of new rigs in 2011.

Income tax expense increased $11.5 million or 58% in the second quarter of 2011 compared to the second quarter of 2010 primarily due to increased income. Our effective tax rate was 38.7% for the second quarter of 2011 and 38.3% for the second quarter of 2010. There was no current income tax expense for the second quarter of 2011 as compared with $3.8 million or 19% of total income tax expense in the second quarter of 2010 due to expected bonus depreciation for 2011. We did not pay any income taxes in the second quarter of 2011.

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Six Months Ended June 30, 2011 versus Six Months Ended June 30, 2010

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

	Six Months Ended June 30,		Percent
	2011	2010	Change
Total revenue	$ 538,900,000	$ 411,153,000	31%
Net income	$ 90,846,000	$ 68,328,000	33%
Contract Drilling:			
Revenue	$ 213,171,000	$ 132,915,000	60%
Operating costs excluding depreciation	$ 117,082,000	$ 87,441,000	34%
Percentage of revenue from daywork contracts	100%	99%	1%
Average number of drilling rigs in use	71.6	54.5	31%
Average dayrate on daywork contracts	$ 18,304	$ 14,553	26%
Depreciation	$ 36,515,000	$ 30,231,000	21%
Oil and Natural Gas:			
Revenue	$ 241,496,000	$ 190,189,000	27%
Operating costs excluding depreciation, depletion and amortization	$ 64,198,000	$ 48,851,000	31%
Average oil price (Bbl)	$ 87.14	$ 67.12	30%
Average NGL price (Bbl)	$ 42.80	$ 38.01	13%
Average natural gas price (Mcf)	$ 4.29	$ 5.79	(26)%
Oil production (Bbl)	1,147,000	623,000	84%
NGL production (Bbl)	1,046,000	765,000	37%
Natural gas production (Mcf)	21,178,000	19,735,000	7%
Depreciation, depletion and amortization rate (Boe)	$ 14.70	$ 10.92	35%
Depreciation, depletion and amortization	$ 84,818,000	$ 51,655,000	64%
Mid-Stream Operations:			
Revenue	$ 84,132,000	$ 77,479,000	9%
Operating costs excluding depreciation and amortization	$ 65,844,000	$ 61,664,000	7%
Depreciation and amortization	$ 7,610,000	$ 7,923,000	(4)%
Gas gathered MMBtu/day	188,340	181,998	3%
Gas processed MMBtu/day	88,603	79,623	11%
Gas liquids sold gallons/day	342,486	266,793	28%
General and administrative expense	$ 14,388,000	$ 12,735,000	13%
Interest expense, net	$ 727,000	$ 0	NM
Income tax expense	$ 56,872,000	$ 42,325,000	34%
Average interest rate	5.2%	4.7%	11%
Average long-term debt outstanding	$ 202,863,000	$ 51,250,000	NM

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

Contract Drilling

Drilling revenues increased $80.3 million or 60% in the first six months of 2011 versus the first six months of 2010 primarily due to a 31% increase in the average number of drilling rigs in use during the first six months of 2011 compared to the first six months of 2010 and a 26% higher average dayrate in the first six months of 2011 compared to the first six months of 2010. Average drilling rig utilization increased from 54.5 drilling rigs in the first six months of 2010 to 71.6 drilling rigs in the first six months of 2011. Oil prices improved in the first six months of 2011 compared to the first six months of 2010, creating increased demand for drilling rigs.

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Drilling operating costs increased $29.6 million or 34% between the comparative six month periods of 2011 and 2010 primarily due to increased utilization and increased direct cost due to higher personnel cost. Due to an increase in activity over last year s levels, competition to keep qualified labor has increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all divisions. Contract drilling depreciation increased $6.3 million or 21% primarily due to increased utilization and from capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $51.3 million or 27% in the first six months of 2011 as compared to the first six months of 2010 primarily due to an increase in equivalent production volumes of 22% and an increase in oil and NGL prices partially offset by decreases in prices for natural gas. Average oil and NGL prices between the comparative quarters increased 30% to $87.14 per barrel and 13% to $42.80 per barrel, respectively, natural gas prices decreased 26% to $4.29 per Mcf. In the first six months of 2011, as compared to the first six months of 2010, oil production increased 84%, NGL production increased 37% and natural gas production increased 7%. Production for the first six months of 2010 was negatively impacted by an unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production and production growth was hampered by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $15.3 million or 31% between the comparative six months of 2011 and 2010 due to increases in lease operating expenses due to increased well servicing costs and higher saltwater disposal fees and higher gross production taxes due to higher oil prices and revenue from increased production between quarters. Lease operating expenses per Boe increased 3% to $6.69.

Depreciation, depletion and amortization (DD&A) increased $33.2 million or 64% primarily due to a 35% increase in our DD&A rate and a 22% increase in equivalent production. The increase in our DD&A rate in the first six months of 2011 compared to the first six months of 2010 resulted primarily from increases throughout 2010 and in the first six months of 2011 from increased net book value on new reserves added. 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.

Mid-Stream

Our mid-stream revenues were $6.7 million or 9% higher for in the first six months of 2011 as compared to the first six months of 2010 primarily due to higher NGL volumes and prices. The average price for NGLs sold increased 13%. Gas processing volumes per day increased 11% between the comparative six months and NGLs sold per day increased 28% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day increased due to an increase in volumes processed, upgrades to several of our processing facilities and the doubling in size of our Hemphill facility in the Texas Panhandle. Gas gathering volumes per day increased 3% primarily from new well connections.

Operating costs increased $4.2 million or 7% in the first six months of 2011 compared to the first six months of 2010 primarily due to an 8% increase in prices paid for natural gas purchased and a 13% increase in gas purchased per day. Depreciation and amortization decreased $0.3 million, or 4%, primarily due to decreased amortization on our intangible asset. For 2011, we anticipate an increase in well connections over 2010 due to anticipated drilling activity by operators in the areas of our existing gathering systems along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

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Other

Other revenue of $10.6 million for the first six months of 2010 was primarily attributable to the sale of eight mechanical drilling rigs and from the sale of a gas pipeline in which we owned a 60% interest.

General and administrative expenses increased $1.7 million or 13% in the first six months of 2011 compared to the first six months of 2010 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $0.7 million between the comparative six months of 2011 and 2010. 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 by 11% and our average debt outstanding was $151.6 million higher in the first six months of 2011 as compared to the first six months of 2010 due to the drilling of developmental wells and construction of new rigs in 2011.

Income tax expense increased $14.5 million or 34% in the first six months of 2011 compared to the first six months of 2010 primarily due to increased income. Our effective tax rate was 38.5% for the first six months of 2011 and 38.3% for the first six months of 2010. There was no current income tax expense for the first six months of 2011 as compared with $6.1 million or 14% of total income tax expense for the first six months of 2010 due to expected bonus depreciation for 2011. We did not pay any income taxes in the first six months of 2011.

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 expre 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 to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- our exploration and drilling prospects;
- 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;
- production of oil, NGLs and natural gas reserves;
- 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; and
- our ability to timely secure third party services used in completing our wells.

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

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

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

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

Item 3. Quantitative and Qualitative Disclosure About Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil, NGLs and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, the prices we received for our oil 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 both 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 2011 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 $335,000 per month ($4.0 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 $181,000 per month ($2.2 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $165,000 per month ($2.0 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. Currently, we also have three basis swaps that do not qualify as cash flow hedges. These financial derivatives are intended to support oil and gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

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Oil and Natural Gas Segment:

At June 30, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul 11 Dec 11	Crude oil swap	4,000 Bbl/day	$84.28	WTI NYMEX
Jan 12 Dec 12	Crude oil swap	4,500 Bbl/day	$95.91	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	2,000 Bbl/day	$102.05	WTI NYMEX
Jul 11 Dec 11	Natural gas swap	10,000 MMBtu/day	$4.43	CEGT
Jul 11 Dec 11	Natural gas swap	70,000 MMBtu/day	$4.87	IF NYMEX (HH)
Jul 11 Dec 11	Natural gas basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 NYMEX
Jan 12 Dec 12	Natural gas swap	30,000 MMBtu/day	$5.05	IF NYMEX (HH)
Jan 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Jul 11 Dec 11	Liquids swap (1)	644,406 Gal/mo	$0.97	OPIS Conway

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and normal butane.

At June 30, 2011, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jul 11 Dec 11	Natural gas basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 NYMEX
Jul 11 Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.21)	CEGT NYMEX
Jul 11 Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.23)	PEPL NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit facility and the Notes. The credit facility debt, at our election bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. Under our Notes payable, 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, beginning on November 15, 2011).

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, 2011 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 six months ended June 30, 2011 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

For information regarding legal proceedings, see Item 3 of our Form 10-K for the fiscal year ended December 31, 2010. There have been no significant changes to what was disclosed in the Form 10-K.

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Item 1A. Risk Factors

In addition to the other information set forth in this 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, 2010, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2010.

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, 2011:

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, 2011 to April 30, 2011	7,318	$ 63.43	7,318	0
May 1, 2011 to May 31, 2011	90	55.71	90	0
June 1, 2011 to June 30, 2011	239	54.70	239	0
Total	7,647	$ 63.07	7,647	0

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the second quarter 2011 vesting distribution for grants previously made from our Unit Corporation Stock and Incentive Compensation Plan adopted May 3, 2006.

(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. Reserved and Removed

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibits:

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

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SIGNATURES

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

Unit Corporation

Date: August 4, 2011

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

Date: August 4, 2011

By: /s/ David T. Merrill
DAVID T. MERRILL
Chief Financial Officer and
Treasurer