UNIT CORP
Form 10-Q
May 01, 2012
Table of Contents

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2012

OR

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

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

[Commission File Number 1-9260]

UNIT CORPORATION

(Exact name of registrant as specified in its charter)

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

(918) 493-7700

(Registrant s telephone number, including area code)

None

(Former name, former address and former fiscal year,

if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [x] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [x] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [x]

As of April 20, 2012, 48,563,968 shares of the issuer's common stock were outstanding.

Table of Contents

FORM 10-Q

UNIT CORPORATION

TABLE OF CONTENTS

Table of Contents

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 number of wells we plan to drill or rework;
- prices for oil, NGLs and natural gas;
- demand for oil, NGLs and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs and natural gas reserves;
- oil, NGLs and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil, NGLs and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells; and
- our ability to transport or convey our oil or natural gas production to established pipeline systems.

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.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2012	December 31, 2011
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,195	$ 835
Accounts receivable, net of allowance for doubtful accounts of $5,343 both at March 31, 2012 and at December 31, 2011	166,031	165,276
Materials and supplies	7,785	8,202
Current derivative asset (Note 9)	26,592	31,938
Current deferred tax asset	10,936	10,936
Prepaid expenses and other	11,578	11,278
Total current assets	224,117	228,465
Property and equipment:		
Drilling equipment	1,448,635	1,423,570
Oil and natural gas properties on the full cost method:		
Proved properties	3,400,158	3,302,032
Undeveloped leasehold not being amortized	189,183	185,632
Gas gathering and processing equipment	303,477	278,919
Transportation equipment	35,320	34,118
Other	40,942	37,544
	5,417,715	5,261,815
Less accumulated depreciation, depletion, amortization and impairment	2,395,021	2,319,484
Net property and equipment	3,022,694	2,942,331
Deferred offering costs	5,520	5,671
Goodwill	62,808	62,808
Other intangible assets, net	1,542	1,855
Non-current derivative asset (Note 9)	384	4,514
Other assets	10,992	11,076
Total assets	$ 3,328,057	$ 3,256,720

The accompanying notes are an integral part of these

condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	March 31, 2012	December 31, 2011
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 120,842	$ 143,311
Accrued liabilities (Note 4)	47,473	51,733
Income taxes payable	1,415	781
Contract advances	2,059	2,055
Current portion of derivative liabilities (Note 9)	2,775	2,657
Current portion of other long-term liabilities (Note 5)	11,691	12,213
Total current liabilities	186,255	212,750
Long-term debt (Note 5)	315,800	300,000
Non-current derivative liabilities (Note 9)	1,359	0
Other long-term liabilities (Note 5)	110,687	113,830
Deferred income taxes	714,877	683,123
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, 48,572,214 and 48,151,442 shares issued, respectively	9,560	9,541
Capital in excess of par value	413,236	408,109
Accumulated other comprehensive loss	13,503	19,026
Retained earnings	1,562,780	1,510,341
Total shareholders equity	1,999,079	1,947,017
Total liabilities and shareholders equity	$ 3,328,057	$ 3,256,720

The accompanying notes are an integral part of these

condensed consolidated financial statements.

4

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended March 31, 2012	2011
	(In thousands)	
Revenues:		
Contract drilling	$ 140,906	$ 97,988
Oil and natural gas	133,772	109,834
Gas gathering and processing	57,295	39,764
Other	455	(181)
Total revenues	332,428	247,405
Expenses:		
Contract drilling:		
Operating costs	76,173	52,844
Depreciation	21,328	17,297
Oil and natural gas:		
Operating costs	35,609	30,781
Depreciation, depletion and amortization	52,197	40,268
Gas gathering and processing:		
Operating costs	47,613	29,055
Depreciation and amortization	5,134	3,773
General and administrative	7,004	6,892
Interest, net	1,826	54
Total operating expenses	246,884	180,964
Income before income taxes	85,544	66,441
Income tax expense:		
Current	0	0
Deferred	33,105	25,414
Total income taxes	33,105	25,414
Net income	$ 52,439	$ 41,027
Net income per common share:		
Basic	$ 1.10	$ 0.86
Diluted	$ 1.09	$ 0.86

The accompanying notes are an integral part of these

condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended March 31, 2012	2011
	(In thousands)	
Net income	$ 52,439	$ 41,027
Other comprehensive income, net of taxes:		
Change in value of derivative instruments used as cash flow hedges, net of tax of ($1,041) and ($9,184)	(1,736)	(14,827)
Reclassification - derivative settlements, Net of tax of ($3,164) and ($127)	(5,012)	(205)
Ineffective portion of derivatives, net of tax of $769 and $730	1,224	1,179
Comprehensive income	$ 46,915	$ 27,174

The accompanying notes are an integral part of these

condensed consolidated financial statements.

6

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 52,439	$ 41,027
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	79,047	61,577
Unrealized loss on derivatives	1,993	2,328
Deferred tax expense	33,105	25,414
(Gain) loss on disposition of assets	(588)	170
Stock compensation plans	3,692	3,286
Other	1,188	895
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(2,860)	(4,716)
Accounts payable	(21,735)	(15,952)
Material and supplies inventory	417	26
Accrued liabilities	1,545	101
Contract advances	4	2,665
Other - net	(300)	4,384
Net cash provided by operating activities	147,947	121,205
INVESTING ACTIVITIES:		
Capital expenditures	(192,824)	(165,617)
Producing property and other acquisitions	(46)	(4,052)
Proceeds from disposition of assets	3,451	457
Net cash used in investing activities	(189,419)	(169,212)
FINANCING ACTIVITIES:		
Borrowings under line of credit	103,700	88,800
Payments under line of credit	(87,900)	(66,800)
Proceeds from exercise of stock options	0	513
Book overdrafts	26,032	25,371
Net cash provided by financing activities	41,832	47,884
Net increase (decrease) in cash and cash equivalents	360	(123)
Cash and cash equivalents, beginning of period	835	1,359
Cash and cash equivalents, end of period	$ 1,195	$ 1,236

The accompanying notes are an integral part of these

condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO 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 in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 23, 2012, for the year ended December 31, 2011.

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

Balance Sheets at March 31, 2012 and December 31, 2011;

Statements of Income for the three months ended March 31, 2012 and 2011;

Statements of Comprehensive Income for the three months ended March 31, 2012 and 2011; and

Cash Flows for the three months ended March 31, 2012 and 2011.

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 condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three months ended March 31, 2012 and 2011 are not necessarily indicative of the results to be realized for the full year in the case of 2012, or that we realized for the full year of 2011.

With respect to the unaudited financial information for the three month periods ended March 31, 2012 and 2011, 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 May 1, 2012, 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.

Table of Contents

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, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.

At March 31, 2012, 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 as of March 31, 2012, consisted of swaps covering 4.2 MMBoe in 2012 and 1.5 MMBoe in 2013. The effect of those hedges on the March 31, 2012 ceiling test was a $22.4 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 9 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 3 EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended March 31, 2012:			
Basic earnings per common share	$ 52,439	47,829	$ 1.10
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	0	297	(0.01)
Diluted earnings per common share	$ 52,439	48,126	$ 1.09
For the three months ended March 31, 2011:			
Basic earnings per common share	$ 41,027	47,584	$ 0.86
Effect of dilutive stock options, restricted stock and SARs	0	321	0
Diluted earnings per common share	$ 41,027	47,905	$ 0.86

Table of Contents

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Stock options and SARs	149,665	73,500
Average Exercise Price	$ 58.41	$ 64.43

NOTE 4 ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2012	December 31, 2011
	(In thousands)	
Taxes	$ 12,899	$ 13,480
Employee costs	12,732	22,518
Lease operating expenses	8,861	7,346
Interest payable	6,981	2,647
Hedge settlements	1,649	1,844
Other	4,351	3,898
Total accrued liabilities	$ 47,473	$ 51,733

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

Long-Term Debt

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

	March 31, 2012	December 31, 2011
	(In thousands)	
Credit agreement with average interest rates, of 2.2% and 2.7% at March 31, 2012 and December 31, 2011, respectively	$ 65,800	$ 50,000
6.625% senior subordinated notes due 2021	250,000	250,000
Total long-term debt	$ 315,800	$ 300,000

Table of Contents

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) that replaced our previous credit agreement which was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect as the commitment amount (currently $250.0 million) or the value of the borrowing base as determined by the lenders (currently $600.0 million), but in either event, not to exceed the maximum credit agreement amount of $750.0 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. In connection with this new credit agreement, we paid $1.8 million in origination, agency, syndication and other related fees. We are amortizing these fees over the life of the credit agreement.

The amount of the borrowing base, which is subject to redetermination on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the Prime Rate, 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. At March 31, 2012, $60.0 million of our $65.8 million in outstanding borrowings were subject to LIBOR.

We used borrowings under the credit agreement to pay off the commitments issued under our previous credit agreement. In addition, we can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes of the borrowers.

The credit agreement prohibits, among other things:

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

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

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

As of March 31, 2012, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million of our 6.625% Senior Subordinated Notes due 2021 (the 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 agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were 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

Table of Contents

registration statement are full and unconditional and joint and several, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on 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), 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 March 31, 2012.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	00000000000 **March 31, 2012**	00000000000 **December 31, 2011**
	(In thousands)	
ARO liability	$ 92,649	$ 96,446
Workers compensation	16,960	17,026
Separation benefit plans	6,982	6,845
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,524	2,463
	122,378	126,043
Less current portion	11,691	12,213
Total other long-term liabilities	$ 110,687	$ 113,830

Estimated annual principle payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2012 (and through 2016) are $11.7 million, $21.4 million, $3.6 million, $3.0 million and $68.8 million, respectively.

Table of Contents

NOTE 6 ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets (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:

	Three Months Ended March 31,	
	2012	**2011**
	(In thousands)	
ARO liability, January 1:	$ 96,446	$ 69,265
Accretion of discount	1,101	874
Liability incurred	1,204	1,559
Liability settled	(1,052)	(359)
Revision of estimates	(5,050)[(1)]	(1)
ARO liability, March 31:	92,649	71,338
Less current portion	2,904	1,836
Total long-term plugging liability	$ 89,745	$ 69,502

(1) Plugging liability estimates were revised in March 2012 for updates in the cost of services used to plug wells over the preceding year. Although cost per well increased, a slight decrease in the inflation factor resulted in a decrease in estimated cost.

NOTE 7 NEW ACCOUNTING PRONOUNCEMENTS

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 FASB 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. Other than modification to disclosure, there was no significant impact 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. 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 chose to present net income and comprehensive income as two consecutive statements in our financial statements.

Table of Contents

Testing Goodwill for Impairment. In August 2011, the FASB issued ASU 2011-08 *Intangibles-Goodwill and Other (ASC 350): Testing Goodwill for Impairment*. This ASU is intended to simplify how entities, both public and nonpublic, test goodwill for impairment. ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is "more likely than not" that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in ASC 350, Intangibles-Goodwill and Other. The more-likely-than-not threshold is defined as having a likelihood of more than 50%. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

NOTE 8 STOCK-BASED COMPENSATION

For both the three months ended March 31, 2012 and 2011, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.3 million, and capitalized stock compensation cost for oil and natural gas properties of $0.6 million. For these same periods, the tax benefit related to this stock based compensation was $0.9 million. The remaining unrecognized compensation cost related to unvested awards at March 31, 2012 is approximately $20.7 million of which $3.9 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 1.0 year.

We did not grant any stock options or SARs during either of the three month periods ending March 31, 2012 and 2011.

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Shares granted	367,936	192,581
Estimated fair value (in millions)	$ 15.6	$ 10.0
Percentage of shares granted expected to be distributed	89%	93%

The restricted stock awards granted during the first three months of 2012 and 2011 are being recognized over a three year vesting period, except for a portion of those granted to certain executive officers. As to those executive officers, 30% of the shares granted, or 46,441 shares granted in 2012 and 20,062 shares granted in 2011 (the performance shares), will cliff vest in the first half of 2015 and 2014, respectively. The actual number of performance shares that vest in 2014 and 2015 will be based on the company s achievement of certain performance criteria over a three-year period, and will range from 50% to 150% of the restricted shares granted as performance shares. Based on the first year s results, the participants would receive less than 100% of the performance based shares. Total 2012 awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first three months of 2012 by an aggregate of $0.8 million.

14

Table of Contents

NOTE 9 DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of March 31, 2012, our derivative transactions consisted only of swaps. Swaps are where 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.

Oil and Natural Gas Segment:

At March 31, 2012, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr 12 Dec 12	Crude oil swap	6,250 Bbl/day	$97.72	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	4,000 Bbl/day	$102.68	WTI NYMEX
Apr 12 Dec 12	Natural gas swap	30,000 MMBtu/day	$5.05	IF NYMEX (HH)
Apr 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Jul 12 Sep 12	Natural gas swap	20,000 MMBtu/day	$2.98	IF NYMEX (HH)
Apr 12 Dec 12	Liquids swap (1)	180,006 Gal/mo	$2.11	OPIS Conway
Apr 12 Jun 12	Liquids swap (2)	1,000,028 Gal/mo	$0.78	OPIS Mont Belvieu
Jul 12 Dec 12	Liquids swap (3)	310,000 Gal/mo	$0.69	OPIS Mont Belvieu

(1) Types of liquids involved are natural gasoline.

(2) Types of liquids involved are natural gasoline and ethane.

(3) Types of liquids involved are ethane.

Subsequent to March 31, 2012, the following cash flow hedges were entered into:

Term	Commodity	Hedged Volume	Price	Hedged Market
Jan 13 Dec 13	Natural gas collar	20,000 MMBtu/day	$3.25 -$3.72	IF NYMEX (HH)
Jan 13 Dec 13	Natural gas swap	10,000 MMBtu/day	$3.21	IF NYMEX (HH)

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

		Derivative Assets Fair Value	
	Balance Sheet Location	March 31, 2012	December 31, 2011
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			

Current	Current derivative asset	$ 26,592	$ 31,938
Long-term	Non-current derivative asset	384	4,514
Total derivatives designated as hedging instruments		26,976	36,452
Total derivative assets		$ 26,976	$ 36,452

Table of Contents

	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2012 (In thousands)	December 31, 2011
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current portion of derivative liabilities	$ 2,775	$ 2,657
Long-term	Non-current derivative liabilities	1,359	0
Total derivatives designated as hedging instruments		4,134	2,657
Total derivative liabilities		$ 4,134	$ 2,657

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

We recognize in accumulated 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 March 31, 2012 and 2011, we had a gain of $13.5 million and a loss of $20.7 million, net of tax, respectively, in accumulated OCI.

Based on market prices at March 31, 2012, we expect to transfer a gain of approximately $14.6 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 March 31, 2012 are expected to mature by December 2013.

Certain derivatives do not qualify as cash flow hedges. Currently, all of our derivatives qualify for cash flow treatment; however, during 2011, we had three basis swaps that did not qualify as cash flow hedges. For those types of derivatives, any changes in the fair value that occurred before their maturity (i.e., temporary fluctuations in value) were reported in the unaudited condensed consolidated statements of income 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 in our oil and natural gas revenues.

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended March 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1) 2012 (In thousands)	2011
Interest rate swaps	$ 0	$ (840)
Commodity derivatives	(13,503)	(19,864)
Total	$ (13,503)	$ (20,704)

(1) Net of taxes.

16

Table of Contents

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended March 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2012	2011	2012	2011
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 8,176	$ 635	$ (1,993)	$ (1,909)
Interest rate swaps	Interest, net	0	(303)	0	0
Total		$ 8,176	$ 332	$ (1,993)	$ (1,909)

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

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (derivatives not designated as hedging instruments) for the three months ended March 31:

	0000	0000	0000
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	
		2012	2011
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ 0	$ (601)
Total		$ 0	$ (601)

NOTE 10 FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value 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. We corroborate these inputs based on recent transactions and broker quotes and compare with actual settlements.

Table of Contents

The following tables set forth our recurring fair value measurements:

	March 31, 2012		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$ 23,341	$ 14,330	$ 37,671
Liabilities	(14,411)	(418)	(14,829)
	$ 8,930	$ 13,912	$ 22,842

	December 31, 2011		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$ 9,698	$ 34,321	$ 44,019
Liabilities	(9,518)	(706)	(10,224)
	$ 180	$ 33,615	$ 33,795

Certain natural gas fixed price swaps were transferred from Level 3 to Level 2 as of March 31, 2012 due to enhances in the Company s ability to obtain and corroborate observable significant inputs to assess the fair value. The Company s policy is to recognize transfers in and/or out of fair value hierarchy levels as of the end of the quarterly reporting period in which the event or change in circumstances causing the transfer occurred.

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

Level 2 Fair Value Measurements

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

Level 3 Fair Value Measurements

Commodity Derivatives. The fair values of our natural gas and natural gas liquids 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.

Table of Contents

The following tables are reconciliations of our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended March 31, 2012		For the Three Months Ended March 31, 2011	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$ 0	$ 33,615	$ (1,614)	$ 10,868
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	0	11,417	(303)	4,305
Included in other comprehensive income (loss)	0	2,111	253	(1,765)
Settlements	0	(11,307)	303	(4,040)
Transfers out of Level 3 into Level 2	0	(21,924)	0	0
End of period	$ 0	$ 13,912	$ (1,361)	$ 9,368
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ 0	$ 110	$ 0	$ 265

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

The following table provides quantitative information about our Level 3 unobservable inputs at March 31, 2012:

	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Commodity contracts [(1)]	$ 13,912	Discounted cash flow	Forward commodity price curve	$ 1.95-$3.02

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

Based on our valuation at March 31, 2012, 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.

At March 31, 2012, the carrying values on the unaudited condensed consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and consideration of our non-performance risk, long-term debt associated with our credit agreement at March 31, 2012 approximates its fair value. This debt would be classified as Level 2.

The carrying amount of long-term debt associated with the Notes reported in the unaudited condensed consolidated balance sheet as of March 31, 2012 and December 31, 2011 was $250.0 million. We estimated the fair value of these Notes using quoted marked prices at

March 31, 2012 and December 31, 2011 which were $257.5 million and $250.6 million, respectively. These Notes would be classified as Level 2.

Table of Contents

NOTE 11 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.

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 March 31,	
	2012	**2011**
	(In thousands)	
Revenues:		
Contract drilling	$ 152,459	$ 112,508
Elimination of inter-segment revenue	(11,553)	(14,520)
Contract drilling net of inter-segment revenue	140,906	97,988
Oil and natural gas	133,772	109,834
Gas gathering and processing	74,255	57,008
Elimination of inter-segment revenue	(16,960)	(17,244)
Gas gathering and processing net of inter-segment revenue	57,295	39,764
Other	455	(181)
Total revenues	$ 332,428	$ 247,405
Operating income:		
Contract drilling	$ 43,405	$ 27,847
Oil and natural gas	45,966	38,785
Gas gathering and processing	4,548	6,936
Total operating income [1]	93,919	73,568
General and administrative expense	(7,004)	(6,892)
Interest expense, net	(1,826)	(54)
Other	455	(181)
Income before income taxes	$ 85,544	$ 66,441

(1) Total 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.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of March 31, 2012, and the related condensed consolidated statements of income and comprehensive income for the three-month periods ended March 31, 2012 and 2011 and the condensed consolidated statements of cash flows for the three-month periods ended March 31, 2012 and 2011. These interim financial statements are the responsibility of the Company s management.

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

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2011, and the related consolidated statements of operations, shareholders equity and of cash flows for the year then ended (not presented herein), and in our report dated February 23, 2012, 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, 2011, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 1, 2012

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, NGLs 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.

Our 2012 capital budget for all of our business segments forecasts a 6% increase over our 2011 capital expenditures, excluding acquisitions. Our oil and natural gas segment s capital budget is $457 million, an 11% decrease over 2011, excluding acquisitions. We plan to continue our aggressive drilling program into 2012 with a significant portion of the wells being horizontal. Our drilling segment s capital budget is $120.0 million, a 27% decrease over 2011. Our plans for 2012 include the construction of one new 1,500 horsepower diesel-electric drilling rig, as well as continuing to refurbish and upgrade several of our existing drilling rigs in our fleet in order that those rigs can be used in horizontal drilling operations. Our mid-stream segment s capital budget is $224.0 million, a 182% increase over 2011. The increase is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as many new projects including new plants discussed further in the Executive Summary.

In developing our initial overall operating budget for 2012, we used average oil and natural gas prices of $90.00 per Bbl and $3.50 per Mcf. Our budget is subject to possible adjustments for various reasons including changes in commodity prices and industry conditions. Our 2012 operating budget will be funded using internally generated cash flow and borrowings under our credit agreement.

Executive Summary

Contract Drilling

The rate at which our drilling rigs were used (our utilization rate) for the first quarter 2012 was 64%, compared to 65% and 58% for the fourth quarter of 2011 and the first quarter of 2011, respectively.

Dayrates for the first quarter of 2012 averaged $19,838, a 3% increase over the fourth quarter of 2011 and an increase of 12% over the first quarter of 2011. These increases were due primarily to increased demand for drilling rigs in the 1,000 to 1,500 horsepower range which are used in horizontal drilling and provide for higher rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the first quarter of 2012 increased 3% over the fourth quarter of 2011 and 43% over the first quarter of 2011. The increases were primarily due to increases in dayrates over the fourth quarter of 2011 and increases in both dayrates and utilization over the first quarter of 2011.

Operating cost per day for the first quarter of 2012 decreased 2% from the fourth quarter of 2011 and increased 22% over the first quarter of 2011. The decreases from the fourth quarter were due to decreases in third-party charges offset by higher direct expenses due to pay increases in the Rockies Division during the first quarter of 2012. The increases over the first quarter of 2011 are 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. However, with the current weakened natural gas market, operators are focusing on drilling for oil and NGLs. With this focus is a shift toward drilling in shallower oil plays, like the Mississippian and Permian, potentially resulting in a change in the mix of the drilling rigs used in our fleet to lower horsepower rigs which have a lower dayrate and margin. Today, approximately 96% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 97% are drilling horizontal or directional wells.

As of March 31, 2012, we had 53 term drilling contracts with original terms ranging from six months to three years. Thirty-seven of these contracts are up for renewal in 2012, 11 in the second quarter, 18 in the third quarter and eight in the fourth quarter and 16 are up for renewal in 2013 and later. These contracts include the term contracts for the new drilling rigs discussed below. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate.

During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party and we placed a new 1,500 horsepower, diesel-electric drilling rig into service, initially working under a three year contract in Wyoming. Additionally, we are building another new 1,500 horsepower, diesel-electric drilling rig to be used in North Dakota starting in the second quarter of 2012 (also under a three year contract). Upon deployment of the new drilling rig during the second quarter of 2012, this segment will have 128 drilling rigs in its fleet.

Our anticipated 2012 capital expenditures for this segment are $120.0 million, a 27% decrease from 2011.

Oil and Natural Gas

First quarter 2012 production from our oil and natural gas segment was 3,275,000 barrels of oil equivalent (Boe), a 1% increase over the fourth quarter of 2011 and a 20% increase over the first quarter of 2011. 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 previous acquisitions. Production for the first quarter of 2012 was negatively impacted approximately 461 MMcfe by an unexpected shut-in of some of our production from operational issues experienced at third-party facilities associated with our Granite Wash and Wilcox plays. First quarter 2012 oil and NGL production was 42% of our total production compared to 38% of our total production over the first quarter of 2011.

First quarter 2012 oil and natural gas revenues decreased 4% from the fourth quarter of 2011 and increased 22% over the first quarter of 2011. The decreases from the fourth quarter of 2011 were primarily due to decreases in NGL and natural gas prices. The increases over the first quarter of 2011 were primarily due to increased production offset by decreased NGL and natural gas prices.

Our oil prices for the first quarter of 2012 increased 9% over the fourth quarter of 2011 and 14% over the first quarter of 2011, respectively. Our NGL and natural gas prices decreased 11% and 18%, respectively, from the fourth quarter of 2011 and decreased 2% and 22%, respectively, from the first quarter of 2011.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 4% from the fourth quarter of 2011 and increased 24% over the first quarter of 2011. The decrease from the fourth quarter 2011 was primarily attributable to decreases in NGL and natural gas prices. The increase over the first quarter 2011 was primarily attributable to increased production and from developmental drilling and acquisitions and increases in oil prices.

Operating cost per Boe produced for the first quarter of 2012 decreased 6% from the fourth quarter of 2011 and decreased 3% from the first quarter of 2011. The costs were lower in the respective periods due primarily to lower gross production taxes. Production taxes decreased due to lower commodity prices between the periods.

For 2012 we hedged approximately 6,100 Bbls per day of oil production and approximately 50,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $97.55 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.09. The average basis differential for the applicable swaps is ($0.28). For 2012 we hedged NGLs of 1,966 Bbls per day in the first quarter, 926 Bbls per day in the second quarter, 380 Bbls per day in the third quarter, and 380 Bbls per day in the fourth quarter. The NGLs are hedged under swap contracts at an average price of $42.53 per barrel in the first quarter, $41.15 per barrel in the second quarter, $51.28 per barrel in the third quarter, and $50.28 per barrel in the fourth quarter.

Currently for 2013 we have hedged 4,000 Bbls per day of oil production and 30,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $102.68 per barrel. The natural gas production is hedged by a swap for 10,000 Mmbtu per day and a collar for 20,000 Mmbtu per day. The swap transaction was done at a comparable average NYMEX price of $3.21. The collar transaction was done at a comparable average NYMEX floor price of $3.25 and ceiling price of $3.72.

For 2012, we plan to participate in the drilling of 160 wells and our capital expenditures budget is $457.0 million (excluding acquisitions). During the first quarter of 2012, we completed drilling 44 wells (18.37 net wells). Our 2012 production guidance is approximately 13.2 to 13.5 MMBoe, an increase of 9% to 12% over 2011, however continued weakness in natural gas prices combined with high gas storage levels could result in curtailments leading to downward revisions to our production guidance.

Mid-Stream

First quarter 2012 liquids sold per day increased 2% over the fourth quarter of 2011 and increased 59% over the first quarter of 2011. The increases were primarily the result of upgrades and expansions to existing plants and the connection of new wells. For the first quarter of 2012, gas processed per day decreased 1% from the fourth quarter of 2011 and increased 79% over the first quarter of 2011. In 2011 and 2012, we upgraded several of our existing processing facilities and added a processing plant which was the primary reason for increased volumes. The decrease in the first quarter of 2012 compared to the fourth quarter of 2011 was primarily due to curtailments at our Hemphill facility in the Granite Wash play due to operational issues experienced at a third-party facility. For the first quarter of 2012, gas gathered per day decreased 2% from the fourth quarter of 2011 and increased 35% over the first quarter of 2011. The increase over the first quarter of 2011 was primarily from new well connects. The decrease from the fourth quarter of 2011 was primarily due to operational issues experienced at a third-party facility in the first quarter of 2012.

Table of Contents

NGL prices in the first quarter of 2012 decreased 9% from the price received in the fourth quarter of 2011 and 12% from the price received in the first quarter of 2011. The price of NGLs affects the revenue in our mid-stream operations as it relates to our share of revenues received from our percent of proceeds (POP) contract structure.

Direct profit (mid-stream revenues less mid-stream operating expense) for the first quarter of 2012 increased 26% over the fourth quarter of 2011 and decreased 10% from the first quarter of 2011. The increase resulted primarily from the decrease in cost of gas purchased, and to a lesser extent from reduced liquids revenue due to lower prices. The decrease from the first quarter of 2011 was primarily due to the renegotiation of certain contracts with some of our customers at one of our processing plants during the first quarter of 2011 that changed the contracts from percent of index to POP. Total operating cost for our mid-stream segment for the first quarter of 2012 decreased 15% from the fourth quarter of 2011 due to both decreases in price and volumes for gas purchased and increased 64% over the first quarter of 2011 due primarily to the increase in gas purchased volumes.

Our Hemphill County facility in Texas is currently processing approximately 100 MMcf per day, after the addition of our fourth gas processing plant, completed in the fourth quarter of 2010. Due to the continued high level of activity around the Hemphill facility, we are installing an additional 45 MMcf per day gas processing plant which will increase this facility s processing capacity to approximately 160 MMcf per day. This new plant should be completed during the second quarter of 2012.

At our Cashion facility, we are continuing to connect new wells to the system and due to this activity, we have installed an additional processing plant. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant has been completed and became operational at the end of March 2012. With the installation of this new plant, our total processing capacity increased to approximately 50 MMcf per day at our Cashion facility.

We are also very active in the Mississippian play in north central Oklahoma. We completed construction of a new gathering system and gas processing plant in Grant County, Oklahoma during the fourth quarter of 2011. This system consists of approximately seven miles of gathering pipeline and a gas processing plant. Also in this area, we have begun construction of another gathering system and processing plant in Noble and Kay counties in Oklahoma, the Bellmon system. This system will initially consist of approximately 10 miles of 12 and 16 pipe with a 10 MMcf per day gas processing plant that will be upgraded to a 30 MMcf per day gas processing plant in the fourth quarter of 2012. We are also planning to connect our existing Remington gathering system to the new Bellmon system. Connecting these two systems will require laying approximately 26 miles of pipeline and installing related compression which is scheduled to be completed in the third quarter of 2012. Also at our Bellmon system, we are planning to extend the system approximately 14 miles to connect to a third-party producer. We anticipate this extension will also be completed in the third quarter of 2012.

Along with the activities in the mid-continent area, we are continuing to expand operations in the Appalachian region. The Bruceton Mills gathering system located in West Virginia became operational in the fourth quarter of 2011. In addition to the Bruceton Mills gathering system, construction continues on an additional gathering facility in Allegheny and Butler counties, Pennsylvania. The first phase of this project consists of approximately seven miles of gathering pipeline and a compressor station. The first well has been connected to this system and is currently flowing into a third-party transmission line with an additional five wells scheduled to be connected in the second quarter of 2012.

Our anticipated capital expenditures for 2012 are $224.0 million.

Table of Contents

Financial Condition and Liquidity

Summary

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

- the 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.

The following is a summary of certain financial information as of March 31, 2012 and 2011 and for the three months ended March 31, 2012 and 2011:

	March 31, 2012	March 31, 2011	% Change
	(In thousands except percentages)		
Working capital	$ 37,862	$ 12,741	197%
Long-term debt	$ 315,800	$ 185,000	71%
Shareholders equity	$ 1,999,079	$ 1,744,864	15%
Ratio of long-term debt to total capitalization	14%	10%	40%
Net income	$ 52,439	$ 41,027	28%
Net cash provided by operating activities	$ 147,947	$ 121,205	22%
Net cash used in investing activities	$ (189,419)	$ (169,212)	12%
Net cash provided by financing activities	$ 41,832	$ 47,884	(13)%

The following table summarizes certain operating information:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	81.5	70	16%
Total number of drilling rigs owned at the end of the period	127	122	4%
Average dayrate	$ 19,838	$ 17,704	12%
Oil and Natural Gas:			
Oil production (MBbls)	720	556	29%
Natural gas liquids production (MBbls)	656	478	37%
Natural gas production (MMcf)	11,400	10,231	11%
Average oil price per barrel received	$ 95.81	$ 84.33	14%
Average oil price per barrel received excluding hedges	$ 100.16	$ 90.78	10%
Average NGL price per barrel received	$ 38.81	$ 39.61	(2)%
Average NGL price per barrel received excluding hedges	$ 37.38	$ 40.36	(7)%
Average natural gas price per mcf received	$ 3.36	$ 4.28	(22)%
Average natural gas price per mcf received excluding hedges	$ 2.45	$ 3.85	(36)%
Mid-Stream:			
Gas gathered MMBtu/day	251,276	185,730	35%
Gas processed MMBtu/day	154,825	86,445	79%
Gas liquids sold gallons/day	522,829	328,333	59%
Number of natural gas gathering systems	35	34	3%
Number of processing plants	11	10	10%

Table of Contents

At March 31, 2012, we had unrestricted cash totaling $1.2 million and had borrowed $65.8 million of the $250.0 million we had elected to have currently available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of 6.625% Senior Subordinated Notes (the 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 agreement, which had $220.3 million outstanding as of May 18, 2011. The remaining proceeds were used for general working capital purposes.

Working Capital

Typically, our working capital balance fluctuates primarily 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 $37.9 million and $12.7 million as of March 31, 2012 and 2011, respectively. The effect of our hedging activity increased working capital by $14.6 million as of March 31, 2012 and decreased working capital by $15.9 million as of March 31, 2011.

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 continues to increase over last year s levels, competition to keep qualified labor has also increased. In the first quarter 2011, we increased compensation for drilling personnel in all our divisions. As a result of continued competition to keep qualified labor, we again increased compensation for rig personnel in the Rockies Division during the first quarter of 2012.

Over the past couple of years, of our customers have drilled more 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 quarter of 2012, our average dayrate was $19,838 per day compared to $17,704 per day for the first quarter of 2011. The average number of our drilling rigs used in the first quarter of 2012 was 81.5 drilling rigs (64%) compared with 70.0 drilling rigs (58%) in the first quarter of 2011. Based on the average utilization of our drilling rigs during the first quarter of 2012, a $100 per day change in dayrates has a $8,150 per day ($3.0 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 the 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 $11.6 million and $14.5 million for the three months of 2012 and 2011, respectively, from our contract drilling segment and eliminated the associated operating expense of $7.3 million and $9.5 million during the three months of 2012 and 2011, respectively, yielding $4.3 million and $5.0 million during the three months of 2012 and 2011, 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, NGLs and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Table of Contents

Based on our first three months of 2012 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 $364,000 per month ($4.4 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of hedging, during the first three months of 2012 was $3.36 compared to $4.28 for the first three months of 2011. Based on our first three months of 2012 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $229,000 per month ($2.7 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 $208,000 per month ($2.5 million annualized) change in our pre-tax operating cash flow. In the first three months of 2012, our average oil price per barrel received, including the effect of hedging, was $95.81compared with an average oil price, including the effect of hedging, of $84.33 in the first three months of 2011 and our first three months of 2012 average NGLs price per barrel received was $38.81 compared with an average NGL price per barrel of $39.61 in the first three months of 2011.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to the lower of unamortized cost or a ceiling. The ceiling is defined as 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, 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. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down cannot be reversed.

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. At March 31, 2012, the 12-month average unescalated prices were $98.00 per barrel of oil, $60.90 per barrel of NGLs and $3.73 per Mcf of natural gas, adjusted for price differentials. The unamortized cost of our oil and natural gas properties did not exceeded the ceiling of our proved oil, NGL and natural gas reserves. Subsequent to March 31, 2012, natural gas prices have continued to decrease and should they remain low they will negatively impact the 12-month average, potentially resulting in a write-down of the carrying value of our oil and natural gas properties for the quarter ending June 30, 2012.

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. Such a reduction could limit our ability to carry out our planned capital projects.

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

Mid-Stream Operations

Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries. Superior is engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, 11 processing plants, 35 gathering systems and 966 miles of pipeline. Superior operates 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 three months of 2012 and 2011, our mid-stream operations purchased $15.9 million and $16.1 million, respectively, of our oil and natural gas segment s production and provided gathering and transportation services to the oil and natural gas segment of $1.0 million and $1.1 million, respectively. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our condensed consolidated financial statements.

Table of Contents

Our mid-stream segment gathered an average of 251,276 MMBtu per day in the first quarter of 2012 compared to 185,730 MMBtu per day in the first quarter of 2011. Processed volumes were 154,825 MMBtu per day in the first quarter of 2012 compared to 86,445 MMBtu per day in the first quarter of 2011. The amount of NGLs we sold was 522,829 gallons per day in the first quarter of 2012 compared to 328,333 gallons per day in the first quarter of 2011. Gas gathering volumes per day in the first three months of 2012 increased 35% compared to the first three months of 2011 primarily from the 62 wells connected to our systems throughout 2011 compared to 52 wells connected throughout 2010. Processed volumes increased 79% over the comparative three months and NGLs sold also increased 59% 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 Agreement and Senior Subordinated Notes

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) that replaced our previous credit agreement which was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect as the commitment amount (currently $250.0 million) or the value of the borrowing base as determined by the lenders (currently $600.0 million), but in either event, not to exceed the maximum credit agreement amount of $750.0 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. In connection with this new credit agreement, we paid $1.8 million in origination, agency, syndication and other related fees. We are amortizing these fees over the life of the credit agreement. At March 31, 2012 and April 20, 2012, borrowings were $65.8 million and $79.8 million, respectively.

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

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	20.00%
BBVA Compass Bank	20.00%
BMO	16.80%
Bank of America, N.A.	16.80%
Comerica Bank	8.80%
Crédit Agricole	8.80%
Wells Fargo Bank, National Association	8.80%
	100.00%

The amount of the borrowing base, which is subject to redetermination on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the Prime Rate, 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. At March 31, 2012, $60.0 million of our $65.8 million in outstanding borrowings were subject to LIBOR.

Table of Contents

We used borrowings under the credit agreement to pay off the commitments issued under our previous credit agreement. In addition, we can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes of the borrowers.

The credit agreement prohibits, among other things:

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

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

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

As of March 31, 2012, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million of our 6.625% Senior Subordinated Notes due 2021 (the 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 agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were used for general working capital purposes. We also terminated two $15.0 million interest rate swaps associated with that debt with a settlement cost to us of $1.5 million.

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, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on 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), 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 March 31, 2012.

Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now working in the Bakken shale in North Dakota under two-year drilling contracts.

During the third quarter of 2011, we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs are initially working under three year contracts. One was placed into service during the fourth quarter of 2011 and the other was placed into service during the first quarter of 2012.

During the fourth quarter of 2011, we entered into an agreement to build a new 1,500 horsepower, diesel-electric drilling rig to be used in North Dakota starting in the second quarter of 2012. This new build rig will initially be working under a three year contract. During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. Upon deployment of the new drilling rig during the second quarter of 2012, this segment will have 128 drilling rigs in its fleet.

Our anticipated 2012 capital expenditures for this segment are $120.0 million. At March 31, 2012, we had commitments to purchase approximately $4.4 million for drill pipe, top drives and related equipment over the next twelve months. We have spent $31.6 million for capital expenditures during the first quarter of 2012 compared to $42.7 million in the first quarter of 2011.

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 44 gross wells (18.37 net wells) in the first quarter of 2012 compared to 34 gross wells (17.19 net wells) in the first quarter of 2011. Total capital expenditures for the first three months of 2012 by this segment, excluding a $4.9 million ARO liability adjustment, totaled $107.2 million. Currently we plan to participate in drilling approximately 160 gross wells in 2012 and estimate our total capital expenditures (excluding acquisitions) for this segment will be approximately $457.0 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.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after 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 acres held by production available for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash, subject to closing adjustments, from an unaffiliated seller. Included in the acquisition were 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 proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

During the fourth quarter of 2011, we leased approximately 60,000 net acres of undeveloped oil and gas leasehold located in south central Kansas for approximately $17.3 million.

Mid-Stream Acquisitions and Capital Expenditures. Our Hemphill County facility in Texas is currently processing approximately 100 MMcf per day, after the addition of our fourth gas processing plant, completed in the fourth quarter of 2010. Due to the continued high level of activity around the Hemphill facility, we are installing an additional 45 MMcf per day gas processing plant which will increase this facility s processing capacity to approximately 160 MMcf per day. This new plant should be completed during the second quarter of 2012.

At our Cashion facility, we are continuing to connect new wells to the system and due to this activity, we have installed an additional processing plant. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant has been completed and became operational at the end of March 2012. With the installation of this new plant, our total processing capacity increased to approximately 50 MMcf per day at our Cashion facility.

We are also very active in the Mississippian play in north central Oklahoma. We completed construction of a new gathering system and gas processing plant in Grant County, Oklahoma during the fourth quarter of 2011. This system consists of approximately seven miles of gathering pipeline and a gas processing plant. Also in this area, we have begun construction of another gathering system and processing plant in Noble and Kay counties in Oklahoma, the Bellmon system. This system will initially consist of approximately 10 miles of 12 and 16 pipe with a 10 MMcf per day gas processing plant that will be upgraded to a 30 MMcf per day gas processing plant in the fourth quarter of 2012. We are also planning to connect our existing Remington gathering system to the new Bellmon system. Connecting these two systems will require laying approximately 26 miles of pipeline and installing related compression which is scheduled to be completed in the third quarter of 2012. Also at our Bellmon system, we are planning to extend the system approximately 14 miles to connect to a third-party producer. We anticipate this extension will also be completed in the third quarter of 2012.

Along with the activities in the mid-continent area, we are continuing to expand operations in the Appalachian region. The Bruceton Mills gathering system located in West Virginia became operational in the fourth quarter of 2011. In addition to the Bruceton Mills gathering system, construction continues on an additional gathering facility in Allegheny and Butler counties, Pennsylvania. The first phase of this project consists of approximately seven miles of gathering pipeline and a compressor station. The first well has been connected to this system and is currently flowing into a third-party transmission line with an additional five wells scheduled to be connected in the second quarter of 2012.

During the first quarter of 2012, our mid-stream segment incurred $24.6 million in capital expenditures as compared to $9.0 million in the first quarter of 2011. For 2012, we have budgeted capital expenditures of approximately $224.0 million.

Table of Contents

Contractual Commitments

At March 31, 2012, 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)	$ 477,348	$ 17,990	$ 35,980	$ 101,002	$ 322,376
Operating leases (2)	15,541	8,494	6,443	533	71
Drill pipe, drilling components and equipment purchases (3)	4,363	4,363	0	0	0
Total contractual obligations	$ 497,252	$ 30,847	$ 42,423	$ 101,535	$ 322,447

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our March 31, 2012 interest rates of 6.625% for the Notes and 2.2% for the credit agreement.

(2) We lease office space or yards in Elmwood, 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 September, 2017. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) We have committed to purchase approximately $4.4 million of new drilling rig components, drill pipe, drill collars and related equipment over the next twelve months.

Table of Contents

At March 31, 2012, 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)	$ 2,524	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 6,982	$ 567	Unknown	Unknown	Unknown
Derivative liabilities commodity hedges	$ 4,134	$ 2,775	$ 1,359	$ 0	$ 0
Asset retirement liability (3)	$ 92,649	$ 2,904	$ 22,240	$ 4,813	$ 62,692
Gas balancing liability (4)	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ 0	Unknown	Unknown	Unknown	Unknown
Workers compensation liability (6)	$ 16,960	$ 8,220	$ 2,743	$ 1,205	$ 4,792

(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 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 $22,000 in both 2011 and 2010. There have been no re-purchases in 2012 through the first quarter.

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

Table of Contents

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 agreement. 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. Currently, we do not have any interest rate swaps.

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 first quarter 2012 average daily production, the approximated percentages of our production that we have hedged are as follows:

Oil and Natural Gas Segment:

	Q2 12	Q3 12	Q4 12	2013
Daily oil production	79%	79%	79%	51%
Daily natural gas production	36%	52%	36%	24%
Natural gas liquids production	13%	5%	5%	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 March 31, 2012, we determined that there was no material risk of non-performance by our counterparties. At March 31, 2012, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2012 (In millions)
Bank of Montreal	$ 15.1
Bank of America, N.A.	6.9
BNP Paribas	2.9
Comerica Bank	0.8
Macquarie Bank	0.5
BP Corporation	(0.2)
BBVA Compass Bank	(0.5)
Crédit Agricole Corporate and Investment Bank, London Branch	(2.7)
Total assets (liabilities)	$ 22.8

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 March 31, 2012, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $26.6 million and $0.4 million, respectively and current and non-current derivative liabilities of $2.8 million and $1.4 million, respectively. At March 31, 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of $24.4 million and $9.7 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 March 31, 2012, we had a gain of $ 13.5 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Table of Contents

Based on market prices at March 31, 2012, we expect to transfer to earnings a gain of approximately $14.6 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 March 31, 2012 are expected to mature by December 2013.

Certain derivatives do not qualify for designation as cash flow hedges. Currently, we do not have any derivatives that do not qualify as cash flow hedges. For derivatives that do not qualify, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported as unrealized gains (losses) in the consolidated statements of income within our oil and natural gas revenues. Changes in the fair value of derivatives designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues. The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at March 31:

	0000000000 **2012**	0000000000 **2011**
	(In thousands)	
Increases (decreases) in:		
Oil and natural gas revenue:		
Realized gains on oil and natural gas derivatives	$ 8,176	$ 453
Unrealized losses on ineffectiveness of cash flow hedges	(1,993)	(1,909)
Unrealized losses on non-qualifying oil and natural gas derivatives	0	(419)
Total increase (decrease) in oil and natural gas revenues due to derivatives	$ 6,183	$ (1,875)

Stock and Incentive Compensation

During the first three months of 2012, we granted awards covering 367,936 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 $15.6 million. Compensation expense will be recognized over their three year vesting periods, and during the first three months of 2012, we recognized $0.6 million in additional compensation expense and capitalized $0.2 million for these awards. During the first three months of 2012, we recognized compensation expense of $2.3 million for all of our restricted stock, stock options and SAR grants and capitalized $0.6 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers compensation, general liability, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 to $1.5 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. 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.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships

We are the general partner of 16 oil and natural gas partnerships which were formed privately or publicly. Each partnership s revenues and costs are shared under formulas set out in that partnership s agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party s share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party s behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party s level of activity and are considered by us to be reasonable. For the first three months of 2012 and 2011, the total we received for all of these fees was $0.4 million and $0.6 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

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 FASB 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. Other than modification to disclosure, there was no significant impact 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. 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 chose to present net income and comprehensive income as two consecutive statements in our financial statements.

Testing Goodwill for Impairment. In August 2011, the FASB issued ASU 2011-08 *Intangibles-Goodwill and Other (ASC 350): Testing Goodwill for Impairment*. This ASU is intended to simplify how entities, both public and nonpublic, test goodwill for impairment. ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in ASC 350, Intangibles-Goodwill and Other. The more-likely-than-not threshold is defined as having a likelihood of more than 50%. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

Table of Contents

Results of Operations

Quarter Ended March 31, 2012 versus Quarter Ended March 31, 2011

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

	Quarter Ended March 31,		Percent
	2012	2011	Change
Total revenue	$ 332,428,000	$ 247,405,000	34%
Net income	$ 52,439,000	$ 41,027,000	28%
Contract Drilling:			
Revenue	$ 140,906,000	$ 97,988,000	44%
Operating costs excluding depreciation	$ 76,173,000	$ 52,844,000	44%
Percentage of revenue from daywork contracts	100%	100%	0%
Average number of drilling rigs in use	81.5	70.0	16%
Average dayrate on daywork contracts	$ 19,838	$ 17,704	12%
Depreciation	$ 21,328,000	$ 17,297,000	23%
Oil and Natural Gas:			
Revenue	$ 133,772,000	$ 109,834,000	22%
Operating costs excluding depreciation, depletion and amortization	$ 35,609,000	$ 30,781,000	16%
Average oil price (Bbl)	$ 95.81	$ 84.33	14%
Average NGL price (Bbl)	$ 38.81	$ 39.61	(2)%
Average natural gas price (Mcf)	$ 3.36	$ 4.28	(22)%
Oil production (Bbl)	720,000	556,000	30%
NGL production (Bbl)	656,000	478,000	37%
Natural gas production (Mcf)	11,400,000	10,231,000	11%
Depreciation, depletion and amortization rate (Boe)	$ 15.78	$ 14.58	8%
Depreciation, depletion and amortization	$ 52,197,000	$ 40,268,000	30%
Mid-Stream Operations:			
Revenue	$ 57,295,000	$ 39,764,000	44%
Operating costs excluding depreciation and amortization	$ 47,613,000	$ 29,055,000	64%
Depreciation and amortization	$ 5,134,000	$ 3,773,000	36%
Gas gathered MMBtu/day	251,276	185,730	35%
Gas processed MMBtu/day	154,825	86,445	79%
Gas liquids sold gallons/day	522,829	328,333	59%
General and administrative expense	$ 7,004,000	$ 6,892,000	2%
Interest expense, net	$ 1,826,000	$ 54,000	NM
Income tax expense	$ 33,105,000	$ 25,414,000	30%
Average interest rate	5.9%	2.8%	111%
Average long-term debt outstanding	$ 304,087,000	$ 175,282,000	73%

(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 $42.9 million or 44% in the first quarter of 2012 versus the first quarter of 2011 primarily due to a 16% increase in the average number of drilling rigs in use during the first quarter of 2012 compared to the first quarter of 2011 and a 12% higher average dayrate in the first quarter of 2012 compared to the first quarter of 2011. Average drilling rig utilization increased from 70.0 drilling rigs in the first quarter of 2011 to 81.5 drilling rigs in the first quarter of 2012. With oil prices improving over previous years and NGL prices remaining strong compared to natural gas prices, there was increased demand for drilling rigs throughout 2011 to drill for liquids; however, with natural gas prices continuing to decline, we may start to see a decrease in drilling activity.

Table of Contents

Drilling operating costs increased $23.3 million or 44% between the comparative first quarters of 2012 and 2011 primarily due to increased utilization, higher direct cost due to increased payroll, supplies and maintenance expense and increased indirect cost due to higher personnel benefit cost. As activity continues to increase over last year s levels, competition to keep qualified labor has also increased. In the first quarter 2011, we increased compensation for drilling personnel in all our divisions. As a result of continued competition to keep qualified labor, we again increased compensation for rig personnel in the Rockies Division during the first quarter of 2012. Contract drilling depreciation increased $4.0 million or 23% primarily due to capital expenditures for upgrades to existing drilling rigs in our fleet and from increased utilization.

Oil and Natural Gas

Oil and natural gas revenues increased $23.9 million or 22% in the first quarter of 2012 as compared to the first quarter of 2011 primarily due to an increase in equivalent production volumes of 20% and an increase in oil prices somewhat offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative quarters increased 14% to $95.81 per barrel, NGL prices decreased 2% to $38.81 per barrel and natural gas prices decreased 22% to $3.36 per Mcf. In the first quarter of 2012, as compared to the first quarter of 2011, oil production increased 30%, NGL production increased 37% and natural gas production increased 11%. 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 previous acquisitions. Production for the first quarter of 2012 was negatively impacted approximately 461 MMcfe by an unexpected shut-in of some of our production from operational issues experienced at third-party facilities associated with our Granite Wash and Wilcox plays.

Oil and natural gas operating costs increased $4.8 million or 16% between the comparative first quarters of 2012 and 2011 due to increases in lease operating expenses primarily from increased workover, saltwater disposal fees and compression dehydration expense partially offset by lower gross production taxes. Lease operating expenses per Boe decreased 1% to $6.87.

Depreciation, depletion and amortization (DD&A) increased $11.9 million or 30% primarily due to an 8% increase in our DD&A rate and a 20% increase in equivalent production. The increase in our DD&A rate in the first quarter of 2012 compared to the first quarter of 2011 resulted primarily from increases throughout 2011 and the first quarter of 2012 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 $17.5 million or 44% higher for the first quarter of 2012 as compared to the first quarter of 2011 primarily due to higher NGL volumes sold offset by lower prices. Gas processing volumes per day increased 79% between the comparative quarters and NGLs sold per day increased 59% 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 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 35% primarily from well connections. The average price for natural gas sold decreased 37% and the average price for NGLs sold decreased 12%.

Operating costs increased $18.6 million or 64% in the first quarter of 2012 compared to the first quarter of 2011 primarily due to a 69% increase in the per day gas volumes purchased offset by an 18% decrease in prices paid for natural gas purchased. Depreciation and amortization increased $1.4 million, or 36%, primarily due to increased assets entered into service throughout 2011 and 2012. For 2012, we anticipate further benefit of the additional processing capacity from the Hemphill facility and an increase in well connections over 2011 due to anticipated drilling activity by operators in the areas of our existing gathering systems.

Table of Contents

Other

General and administrative expenses increased $0.1 million or 2% in the first quarter of 2012 compared to the first quarter of 2011 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $1.8 million between the comparative first quarters of 2012 and 2011. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate increased from 2.8% to 5.9% primarily due to the issuance of $250.0 million of Senior Subordinated Notes during the second quarter of 2011 and our average debt outstanding was $128.8 million higher in the first quarter of 2012 as compared to the first quarter of 2011 due to acquisitions in 2011 and construction of new rigs.

Income tax expense increased $7.7 million or 30% in the first quarter of 2012 compared to the first quarter of 2011 primarily due to increased income. Our effective tax rate was 38.7% for the first quarter of 2012 and 38.3% for the first quarter of 2011. There was no current income tax expense for the first quarter of 2012 or 2011 due to expected bonus depreciation. We did not pay any income taxes in the first quarter of 2012.

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 number of wells to be drilled or reworked;
- prices for oil, NGLs and natural gas;
- demand for oil, NGLs and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs and natural gas reserves;
- oil, NGLs and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil, NGLs and natural gas reserves;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells; and
- our ability to transport or convey our oil and natural gas production to established pipeline systems.

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:

Table of Contents

- 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 three months 2012 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 $364,000 per month ($4.4 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $229,000 per month ($2.7 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 $208,000 per month ($2.5 million annualized) change in our pre-tax operating cash flow.

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

Table of Contents

Oil and Natural Gas Segment:

At March 31, 2012, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr 12 Dec 12	Crude oil swap	6,250 Bbl/day	$97.72	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	4,000 Bbl/day	$102.68	WTI NYMEX
Apr 12 Dec 12	Natural gas swap	30,000 MMBtu/day	$5.05	IF NYMEX (HH)
Apr 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Jul 12 Sep 12	Natural gas swap	20,000 MMBtu/day	$2.98	IF NYMEX (HH)
Apr 12 Dec 12	Liquids swap (1)	180,006 Gal/mo	$2.11	OPIS Conway
Apr 12 Jun 12	Liquids swap (2)	1,000,028 Gal/mo	$0.78	OPIS Mont Belvieu
Jul 12 Dec 12	Liquids swap (3)	310,000 Gal/mo	$0.69	OPIS Mont Belvieu

(1) Types of liquids involved are natural gasoline.
(2) Types of liquids involved are natural gasoline and ethane.
(3) Types of liquids involved are ethane.

Subsequent to March 31, 2012, the following cash flow hedges were entered into:

Term	Commodity	Hedged Volume	Price	Hedged Market
Jan 13 Dec 13	Natural gas collar	20,000 MMBtu/day	$3.25 - $3.72	IF NYMEX (HH)
Jan 13 Dec 13	Natural gas swap	10,000 MMBtu/day	$3.21	IF NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of March 31, 2012 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended March 31, 2012 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, 2011. There have been no significant changes to what was disclosed in the Form 10-K.

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

Table of Contents

December 31, 2011, 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, 2011.

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

The following table provides information relating to our repurchase of common stock for the three months ended March 31, 2012:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2012 to January 31, 2012	0	$ 0	0	0
February 1, 2012 to February 29, 2012	0	0	0	0
March 1, 2012 to March 31, 2012	42,762	47.41	42,762	0
Total	42,762	$ 47.41	42,762	0

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the first quarter 2012 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. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Table of Contents

Item 6. Exhibits

Exhibits:

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

Table of Contents

SIGNATURES

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

	Unit Corporation
Date: May 1, 2012	By: /s/ Larry D. Pinkston LARRY D. PINKSTON
	Chief Executive Officer and Director
Date: May 1, 2012	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and
	Treasurer

45