UNIT CORP
Form 10-Q
May 06, 2008

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, 2008

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

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 May 1, 2008, 47,156,303 shares of the issuer's common stock were outstanding.

FORM 10-Q
UNIT CORPORATION

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Forward-Looking Statements

This document contains “forward-looking statements” – meaning, statements related to future, not past, events. In this context, forward-looking statements often address our expected future business and financial performance, and often contain words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “seek,” or “will.” Forward-looking statements by the nature address matters that are, to different degrees, uncertain. For us, some of the particular uncertainties that could adversely or positively affect our future results include: changes in the demand for and the prices of oil and natural gas, the behavior of financial markets, including fluctuations in interest and commodity and equity prices; strategic actions, including acquisitions and dispositions; future integration of acquired businesses; future financial performance of industries which we serve, including, without limitation, the energy industries; and numerous other matters of a national, regional and global scale, including those of a political, economic, business and competitive nature. These uncertainties may cause our actual future results to be materially different than those expressed in our forward-looking statements. We do not undertake to update our forward-looking statements.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2008	December 31, 2007
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 848	$ 1,076
Restricted cash	19	19
Accounts receivable, net of allowance for doubtful accounts of $3,500 at March 31, 2008 and $3,350 at December 31, 2007	174,955	159,455
Materials and supplies	13,850	13,558
Other	24,734	22,907
Total current assets	214,406	197,015
Property and equipment:		
Drilling equipment	1,023,694	987,184
Oil and natural gas properties, on the full cost method:		
Proved properties	1,721,162	1,624,478
Undeveloped leasehold not being amortized	73,307	64,722
Gas gathering and processing equipment	127,611	119,515
Transportation equipment	23,947	23,240
Other	20,238	19,974
	2,989,959	2,839,113
Less accumulated depreciation, depletion, amortization and impairment	980,167	927,759
Net property and equipment	2,009,792	1,911,354
Goodwill	62,808	62,808
Other intangible assets, net	12,636	13,798
Other assets	14,756	14,844
Total assets	$ 2,314,398	$ 2,199,819

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

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

	March 31, 2008	December 31, 2007
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 97,998	$ 100,258
Accrued liabilities	30,313	40,508
Income taxes payable	9,396	—
Contract advances	3,972	6,825
Current portion of derivative liabilities	26,761	56
Current portion of other liabilities	9,871	8,757
Total current liabilities	178,311	156,404
Long-term debt	116,600	120,600
Other long-term liabilities	66,514	59,115
Deferred income taxes	455,992	428,883
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 47,138,795 and 47,035,089 shares issued, respectively	9,301	9,280
Capital in excess of par value	352,258	344,512
Accumulated other comprehensive income (loss)	(21,507)	1,160
Retained earnings	1,156,929	1,079,865
Total shareholders' equity	1,496,981	1,434,817
Total liabilities and shareholders' equity	$ 2,314,398	$ 2,199,819

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

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(In thousands except per share amounts)	
Revenues:		
Contract drilling	$ 147,247	$ 160,285
Oil and natural gas	130,002	86,106
Gas gathering and processing	44,223	30,768
Other	(110)	112
Total revenues	321,362	277,271
Expenses:		
Contract drilling:		
Operating costs	74,461	76,287
Depreciation	15,364	12,717
Oil and natural gas:		
Operating costs	27,601	22,139
Depreciation, depletion and amortization	35,715	29,347
Gas gathering and processing:		
Operating costs	35,072	27,501
Depreciation and amortization	3,481	2,339
General and administrative	6,525	5,182
Interest	820	1,641
Total expenses	199,039	177,153
Income Before Income Taxes	122,323	100,118
Income Tax Expense:		
Current	15,447	22,697
Deferred	29,812	12,939
Total income taxes	45,259	35,636
Net income	$ 77,064	$ 64,482
Net income per common share:		
Basic	$ 1.66	$ 1.39
Diluted	$ 1.65	$ 1.39

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

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 77,064	$ 64,482
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	54,734	44,617
Deferred tax expense	29,812	12,939
Other	4,108	2,379
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(15,650)	8,522
Accounts payable	2,119	(15,877)
Material and supplies inventory	(292)	499
Accrued liabilities	8,729	10,619
Contract advances	(2,853)	(640)
Other – net	1,019	1,166
Net cash provided by operating activities	158,790	128,706
INVESTING ACTIVITIES:		
Capital expenditures	(159,504)	(112,403)
Proceeds from disposition of assets	736	1,153
Other-net	—	(1)
Net cash used in investing activities	(158,768)	(111,251)
FINANCING ACTIVITIES:		
Borrowings under line of credit	56,500	22,100
Payments under line of credit	(60,500)	(44,400)
Proceeds from exercise of stock options	323	191
Book overdrafts	3,427	4,668
Net cash used in financing activities	(250)	(17,441)
Net increase (decrease) in cash and cash equivalents	(228)	14
Cash and cash equivalents, beginning of period	1,076	589
Cash and cash equivalents, end of period	$ 848	$ 603

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

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(In thousands)	
Net income	$ 77,064	$ 64,482
Other comprehensive income,		
Net of taxes:		
Change in value of derivative instruments used as cash flow hedges (net of tax of $13,294 and $877)	(22,664)	(1,534)
Reclassification - derivative settlements (net of tax of $1 and $114)	(1)	(209)
Comprehensive income	$ 54,399	$ 62,739

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

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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 its subsidiaries and affiliates, except as otherwise clearly indicated or as the context otherwise requires.

The accompanying interim condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Form 10-K, filed February 28, 2008, for the year ended December 31, 2007. The accompanying condensed consolidated financial statements include all normal recurring adjustments that we consider necessary to state fairly our financial position at March 31, 2008, results of operations and cash flows for the three months ended March 31, 2008 and 2007. All intercompany transactions have been eliminated.

Our financial statements are prepared in conformity with generally accepted accounting principles (GAAP) in the U.S. Preparing financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the amounts reported in our condensed consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Results for the three months ended March 31, 2008 and 2007 are not necessarily indicative of the results to be realized during the full year. With respect to the unaudited financial information of the Company for the three month periods ended March 31, 2008 and 2007, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards for a review of that information. Its separate report, dated May 6, 2008, 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 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 for its report on the unaudited financial information because that report is not a "report" or a "part" of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 - 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, 2008:					
Basic earnings per common share	$	77,064	46,481	$	1.66
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)		—	319		(0.01)
Diluted earnings per common share	$	77,064	46,800	$	1.65
For the three months ended March 31, 2007:					
Basic earnings per common share	$	64,482	46,330	$	1.39
Effect of dilutive stock options, restricted stock and SARs		—	203		—
Diluted earnings per common share	$	64,482	46,533	$	1.39

The number of stock options and stock appreciaton rights (SARs) (and their average exercise price) not included in the computation of diluted earnings per share for the three months ended March 31, 2008 and 2007 because their option exercise prices were greater than the average market price of our common stock was:

		2008		2007
Options and SARs		105,665		33,000
Average Exercise Price	$	56.33	$	61.40

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NOTE 3 – 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, 2008	December 31, 2007
	(In thousands)	
Revolving credit facility, with interest at March 31, 2008 of 4.7% and December 31, 2007 of 6.0%	$ 116,600	$ 120,600
Less current portion	—	—
Total long-term debt	$ 116,600	$ 120,600

On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of $400.0 million maturing on May 24, 2012. Borrowings under the Credit Facility are limited to a commitment amount that we elect. As of March 31, 2008, the commitment amount was $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the beginning of the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for the first quarter of 2008, which includes the effect of our interest rate swaps, was 5.4%. At March 31, 2008 and April 30, 2008, borrowings were $116.6 million and $115.3 million, respectively.

The borrowing base under the Credit Facility is subject to redetermination by our lenders on April 1 and October 1 of each year. The current borrowing base is $500.0 million. Each redetermination is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. We or the lenders may request a one time special redetermination of the borrowing base between each scheduled redetermination date. In addition, we may request a redetermination following the consummation of an acquisition that meets certain requirements contained in the Credit Facility. The lenders' aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which LIBOR options apply may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate payable at the end of each month and the principal borrowed may be paid anytime, in part or in whole, without a premium or penalty. At March 31, 2008, all of the $116.6 million of our borrowings was subject to LIBOR.

The Credit Facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and

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- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of our lenders.

The Credit Facility also requires that we have at the end of each quarter:

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

On March 31, 2008, we were in compliance with each of these covenants.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2008	December 31, 2007
	(In thousands)	
Plugging liability	$ 34,085	$ 33,191
Derivative liabilities – commodity hedges	32,744	—
Derivative liabilities – interest rate swaps	1,515	249
Workers' compensation	22,717	22,469
Separation benefit plans	5,300	4,945
Gas balancing liability	3,364	3,364
Deferred compensation plan	2,856	2,987
Retirement agreement	565	723
	103,146	67,928
Less current portion including derivative liabilities	36,632	8,813
Total other long-term liabilities	$ 66,514	$ 59,115

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning April 1, 2008 through 2013 are $36.6 million, $15.3 million, $2.5 million, $2.5 million and $118.5 million, respectively. Based on the borrowing rates currently available to us for debt with similar terms and maturities, our long-term debt at March 31, 2008 approximates its fair value.

NOTE 4 – ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) we are required to record the fair value of liabilities associated with the retirement of long-lived assets. We own oil and natural gas wells which we are required to plug and abandon when the oil and natural gas reserves in the wells are depleted or the wells are no longer able to produce. Under FAS 143, these plugging and abondment expenses for a well are recorded in the period in which the liability is incurred (at the time the well is drilled or acquired). We do not have any assets restricted for the purpose of settling these well plugging liabilities.

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The following table shows the activity relating to our well plugging liability:

	Three Months Ended March 31,	
	2008	2007
	(In thousands)	
Plugging liability, January 1:	$ 33,191	$ 33,692
Accretion of discount	422	434
Liability incurred	588	325
Liability settled	(163)	(331)
Revision of estimates	47	135
Plugging liability, March 31	34,085	34,255
Less current portion	710	1,091
Total long-term plugging liability	$ 33,375	$ 33,164

NOTE 5 - NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements. In September 2006, the FASB issued Statement No. 157 (FAS 157), “Fair Value Measurements,” which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied FAS 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of FAS 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of FAS 157 to our financial instruments and the impact was not material. Under FSP 157-2, we will be required to apply FAS 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We are currently reviewing the applicability of FAS 157 to our nonfinancial assets and liabilities and the potential impact that application will have on our consolidated financial statements.

In February 2007, the FASB issued Statement No. 159 (FAS 159), “The Fair Value Option for Financial Assets and Financial Liabilities,” which allows companies to elect to measure specified financial assets and liabilities, firm commitments and non-financial warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. At January 1, 2008, we did not elect the fair value option under FAS 159 and therefore there was no impact on our consolidated financial statements.

Business Combinations. In December 2007, the FASB issued Statement No. 141R (FAS 141R), “Business Combinations,” which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. FAS 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of FAS 141R to our operations and its potential impact on our consolidated financial statements.

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), “Noncontrolling Interest in Consolidated Financial Statements – an amendment to ARB No. 51,” which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. We are currently reviewing the applicability of FAS 160 to our operations and its potential impact on our consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued Statement No. 161 (FAS 161), “Disclosures about Derivative Instruments and Hedging Activities - an Amendment of FASB Statement 133,” which requires enhanced disclosures about how derivative and hedging activities affect our financial position, financial performance and cash flows. FAS 161 is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of FAS 161 to our consolidated financial statement disclosures.

NOTE 6 – STOCK-BASED COMPENSATION

We use Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment, (FAS 123(R)) to account for our stock-based employee compensation. Among other items, FAS 123(R) requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. On adoption of FAS 123(R) at January 1, 2006, we elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Staff Position No. FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards", issued on November 10, 2005. For all unvested stock options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value on the original grant date, is being recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification, is recognized in the financial statements over the vesting period. To the extent equity compensation cost relates to employees directly involved in our oil and natural gas segment these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to our oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights. The value of restricted stock grants is based on the closing stock price on the date of the grant.

For the three months ended March 31, 2008 and 2007, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.5 million and $0.6 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.8 million and $0.1 million, respectively. The tax benefit related to this stock based compensation was $0.9 million and $0.2 million, respectively. The remaining unrecognized compensation cost related to unvested awards at March 31, 2008 is approximately $24.6 million with $5.7 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 1.1 years.

We did not grant any stock options or SARs during the first quarters of 2008 or 2007.

The following table shows the fair value of restricted stock awards granted:

	Three Months Ended March 31, 2008	2007
Number of shares granted	14,500	—
Estimated fair value (in millions)	$ 0.6	$ —
Percentage of shares granted that are expected to be distributed	89%	—

The restricted stock awards granted in the first three months of 2008 increased stock compensation expense and capitalized cost related to oil and natural gas properties for the first quarter of 2008 by less than $0.1 million.

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NOTE 7 – DERIVATIVES

Interest Rate Swaps

We have entered into interest rate swaps to help manage our exposure to possible future interest rate increases. As of March 31, 2008, we had two outstanding interest rate swaps both of which were cash flow hedges. There was no material amount of ineffectiveness. The fair value of these swaps was recognized on the March 31, 2008 balance sheet as current and non-current derivative liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
		($ in thousands)		
December 2007 – May 2012	$ 15,000	4.53%	3 month LIBOR	$ (868)
December 2007 – May 2012	$ 15,000	4.16%	3 month LIBOR	(647)
				$ (1,515)

As a result of these interest rate swaps, interest expense decreased by $0.1 million for the three months ended March 31, 2008. A loss of $0.9 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of March 31, 2008. During the first quarter of 2007, we had an outstanding interest rate swap covering $50.0 million of our bank debt which swapped a variable interest rate for a fixed rate. As a result of that swap, our interest expense decreased by $0.2 million for the three months ended March 31, 2007.

Commodity Hedges

We have entered into various types of derivative instruments covering a portion of our projected natural gas, oil and NGL production or processing, as applicable, to reduce our exposure to market price volatility as discussed more fully below. As of March 31, 2008, our derivative instruments were comprised of swaps and collars defined below:

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

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

- Fractionation Spreads. In our mid-stream segment, we enter into both NGL sales swaps and natural gas purchase swaps, to lock in our fractionation spread for a percentage of our natural gas processed. The fractionation spread is the difference in the value received for the natural gas liquids (NGLs) recovered from natural gas in comparison to the amount received for the equivalent MMBtu's of natural gas if unprocessed.

Currently all of our commodity hedges are cash flow hedges and there is no material amount of ineffectiveness. At March 31, 2008, we recorded the fair value of our commodity hedges on our balance sheet as current derivative assets of $0.1 million and current and non-current derivative liabilities of $32.7 million. During the first quarter of 2007, we had one collar for 10,000 MMBtus/day covering the periods of January through December of 2007 and two collars for 10,000 MMBtus/day each covering the periods of March through December 2007. These collars contained prices ranging from a floor of $6.00 to a ceiling of $10.00. At March 31, 2007, we had current derivative assets of $0.5

million and current derivative liabilities of $1.2 million.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2008, we had a loss of $20.9 million, net of tax, from our oil and natural gas segment derivatives and a gain of $0.3 million, net of tax, from our mid-stream segment derivatives in accumulated other comprehensive income (loss). At March 31, 2008, commodity instruments with a net fair value liability of $26.3 million were short-term and will be settled into earnings within twelve months. Realized gains and losses from our commodity derivative settlements included in revenues and expenses were as follows for the three months ended March 31:

	2008	2007
	(In thousands)	
Increases (decreases) in:		
Oil and natural gas revenue	$ (112)	$ 152
Gas gathering and processing revenue	(119)	—
Gas gathering and processing expense	(182)	—
Impact on pre-tax earnings	$ (49)	$ 152

At March 31, 2008, we had the following cash flow hedges outstanding:

Oil and Natural Gas Segment:

Term	Sell/ Purch.	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Market
Apr'08	Sell	Liquids – swap (1)	582,000 Gal/mo	$1.16	OPIS - Conway
Apr'08	Sell	Liquids – swap (1)	750,000 Gal/mo	$1.11	OPIS – Mont Belvieu
Apr – Dec'08	Sell	Crude oil – swap	1,000 Bbl/day	$91.32	WTI - NYMEX
Apr – Dec'08	Sell	Crude oil - collar	1,000 Bbl/day	$85.00 put & $98.75 call	WTI - NYMEX
Apr – Dec'08	Sell	Crude oil - collar	500 Bbl/day	$90.00 put & $102.50 call	WTI - NYMEX
Apr – Dec'08	Sell	Natural gas – swap	20,000 MMBtu/day	$7.52	IF – Centerpoint East
Apr – Dec'08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.00 put & $8.40 call	IF – Centerpoint East
Apr – Dec'08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.20 put & $8.80 call	IF – Tenn (Zone 0)
Apr – Dec'08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.50 put & $8.70 call	NGPL-TXOK
Jan – Dec'09	Sell	Natural gas – swap	10,000 MMBtu/day	$7.77	IF – Centerpoint East
Jan – Dec'09	Sell	Natural gas – swap	10,000 MMBtu/day	$8.28	IF – Tenn (Zone 0)

(1) Types of liquids involved are ethane and propane.

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Weighted Average Fixed Price	Market
Apr'08	Sell	Liquids – swap (1)	1,836,000 Gal/mo	$ 1.34	OPIS - Conway
Apr'08	Purchase	Natural gas – swap	171,000 MMBtu/mo	$ 6.46	IF - PEPL
May – Jul'08	Sell	Liquids – swap (1)	1,330,000 Gal/mo	$ 1.27	OPIS - Conway
May – Jul'08	Purchase	Natural gas – swap	116,300 MMBtu/mo	$ 6.93	IF - PEPL
Aug – Dec'08	Sell	Liquid – swap (2)	188,000 Gal/mo	$ 1.43	OPIS - Conway
Aug – Dec'08	Purchase	Natural gas – swap	17,000 MMBtu/mo	$ 6.91	IF - PEPL

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and natural butane.
(2) Type of liquid involved is propane.

After March 31, 2008, we entered into the following cash flow hedges:

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Weighted Average Fixed Price	Market
May – Dec'08	Sell	Liquids – swap (1)	507,020 Gal/mo	$ 1.41	OPIS - Conway
May – Jul'08	Purchase	Natural gas – swap	43,175 MMBtu/mo	$ 9.41	IF - PEPL
Aug – Dec'08	Sell	Liquid – swap (2)	217,400 Gal/mo	$ 1.68	OPIS - Conway
Aug – Dec'08	Purchase	Natural gas – swap	63,090 MMBtu/mo	$ 9.55	IF - PEPL

(1) Types of liquids involved are natural gasoline, ethane, isobutane and natural butane.
(2) Type of liquid involved is propane.

Fair Value Measurements

As of January 1, 2008, we applied the provisions of FAS 157 to our financial instruments. FAS 157 establishes a fair value hierarchy 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 valuation technique we use to measure the fair values of our financial instruments is based on the inputs available to us.

The following table sets forth our recurring fair value measurements:

	March 31, 2008			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ —	$ —	$ (1,515)	$ (1,515)
Crude oil swaps	—	(2,241)	—	(2,241)
Natural gas and NGL swaps and crude oil and natural gas collars	—	—	(30,382)	(30,382)

Our Level 2 inputs are determined using estimated internal discounted cash flow calculations using NYMEX futures index for our crude oil swaps. Our level 3 inputs are determined for fair values with multiple inputs. The fair values of interest rate swaps, as well as, natural gas and NGL swaps and crude oil and natural gas collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the agreements.

The following table sets forth a reconciliation of our Level 3 fair value measurements:

	Net Derivatives	
	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)	
January 1, 2008	$ (153)	$ 2,625
Total gains or losses (realized and unrealized):		
Included in earnings (1)	51	554
Included in other comprehensive income (loss)	(1,362)	(33,007)
Purchases, issuance and settlements	(51)	(554)
March 31, 2008	$ (1,515)	$ (30,382)
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held as of March 31, 2008	$ —	$ —

(1) Interest rate swaps and commodity sales swaps and collars are reported in the condensed consolidated statements of income in interest expense and revenues, respectively. Our Mid-stream natural gas purchase swaps are reported in the condensed consolidated statements of income in expense.

NOTE 8 - 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 the performance of each segment based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Our natural gas production in Canada is not significant. Certain information regarding each of our segment's operations follows:

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(In thousands)	
Revenues:		
Contract drilling	$ 163,914	$ 168,813
Elimination of inter-segment revenue	16,667	8,528
Contract drilling net of inter-segment revenue	147,247	160,285
Oil and natural gas	130,002	86,106
Gas gathering and processing	56,559	33,931
Elimination of inter-segment revenue	12,336	3,163
Gas gathering and processing net of inter-segment revenue	44,223	30,768
Other	(110)	112
Total revenues	$ 321,362	$ 277,271
Operating Income (1):		
Contract drilling	$ 57,422	$ 71,281
Oil and natural gas	66,686	34,620
Gas gathering and processing	5,670	928
Total operating income	129,778	106,829
General and administrative expense	(6,525)	(5,182)
Interest expense	(820)	(1,641)
Other income - net	(110)	112
Income before income taxes	$ 122,323	$ 100,118

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

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, 2008, and the related condensed consolidated statements of income and comprehensive income for each of the three-month periods ended March 31, 2008 and 2007 and the condensed consolidated statements of cash flows for the three-month periods ended March 31, 2008 and 2007. 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, 2007, and the related consolidated statements of income, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 28, 2008 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, 2007, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 6, 2008

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 operating results and financial condition by focusing on changes in key measures from year to year. MD&A is organized in the following sections:

- General
- Executive Summary
- Financial Condition and Liquidity
- New Accounting Pronouncements
- Results of Operations

MD&A should be read in conjunction with the condensed consolidated financial statements and related notes included in this report as well as 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 and, as appropriate, and/or one or more of its subsidiaries.

General

We were founded in 1963 as a contract drilling company. Today, 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 to a lesser extent 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.
- Gas Gathering and Processing (Mid-Stream) – carried out by our subsidiary Superior Pipeline Company, L.L.C. This segment buys, sells, gathers, processes and treats natural gas for third parties and for our own account.

With multiple energy segments, we are focused on being a diversified energy company. With this diversification, our goal is to increase the opportunities for us to capitalize on market upswings, while mitigating the potential risks that can occur during industry downturns in a particular segment. We strive to grow all of our segments while maintaining a conservative debt position.

In our contract drilling segment, we focus on maximizing our rig utilization along with retaining key drilling personnel to provide quality service to our drilling customers while continuing to search for opportunities to expand our operational area and rig fleet. Our oil and natural gas segment focuses on low-risk exploration and development drilling to drive reserve growth from internally generated prospects and we make producing property acquisitions on a more limited basis only when the acquisitions meet our economic criteria. We have an annual goal of adding reserves in excess of 150% of annual production. Our mid-stream segment's goal is to expand this segment of our business through both construction of gathering systems and plants while acquiring existing facilities as opportunities become available.

Executive Summary

Contract Drilling

Demand for drilling rigs remained competitive throughout most of 2007 resulting in a decline in dayrates and in this competitive market we have focused on maintaining somewhat consistent utilization rates of approximately 80% to help retain key drilling personnel while preserving as high a dayrate as possible. In the first quarter of 2008, we had a utilization rate of 78% with an average dayrate of $17,997, a decrease of 1% from the fourth quarter of 2007 and 7% from the first quarter of 2007. Direct profit (contract drilling revenue less contract drilling operating expense) decreased 8% and 13% from the fourth quarter of 2007 and the first quarter of 2007, respectively, primarily due to the decrease in dayrates. Operating cost per day increased 1% from the fourth quarter of 2007, but decreased 7% from the first quarter of 2007. In the first quarter of 2008, commodity prices increased significantly and should commodity prices remain strong, we anticipate increases in both utilization percentages and dayrates later in the year as medium depth range drilling rigs industry-wide become more fully utilized. We are constructing two new 1,500 horsepower, diesel electric drilling rigs which we anticipate placing into service in the second quarter of 2008 in our Rocky Mountain Division. We also have plans to build two additional 1,500 horsepower, diesel electric drilling rigs to be placed in service in the fourth quarter of 2008.

Oil and Natural Gas

Production from our oil and natural gas segment in the first quarter of 2008 was 162,000 Mcfe per day, a 2% increase over the fourth quarter of 2007 and a 14% increase over the first quarter of 2007. Increases in production came from wells completed throughout 2007 and in the first quarter of 2008 from our development drilling program. In addition, there was a decrease in production during the first quarter of 2008 due to a third-party processing plant being shut down and in the first quarter of 2007 primarily due to a refinery fire. Oil and natural gas revenues increased 14% from the fourth quarter of 2007 and 51% from the first quarter of 2007. Oil and natural gas prices we received increased significantly in the first quarter of 2008 rising 33% and 21%, respectively, from the fourth quarter of 2007 and 69% and 20%, respectively, from the first quarter of 2007. Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 19% from the fourth quarter of 2007 and 60% from the first quarter of 2007 primarily from the increase in commodity prices and to a lesser extent from an increase in production. Operating cost per Mcfe produced remained unchanged between the first quarter of 2008 and the fourth quarter of 2007 and increased 8% from the first quarter of 2007. We hedged 72 % of our current daily oil production and 40% of our current natural gas production in 2008 to help manage our cash flow and capital expenditure requirements in 2008. Our estimated production for 2008 is 59.0 to 61.0 Bcfe an 8% to 12% increase over 2007. To increase our reserve base, we plan to drill approximately 280 well during 2008, an increase of 11% over 2007. Although increases in commodity prices should result in increased demand for drilling rigs we do not believe the increased demand will significantly affect our ability to find drilling rigs to drill wells under our oil and natural gas and exploration drilling program in 2008. We continue to look for producing property acquisitions which meet our economic requirements.

On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was $16.8 million which consisted of $15.8 million allocated to the reserves of the wells and $1.0 million allocated to the undeveloped leasehold. The production and reserves acquired in this purchase are included in our 2008 results. We continue to look for producing property acquisitions which meet our economic requirements.

Mid-Stream

Our mid-stream segment continues to grow as liquids sold per day increased 8% in the first quarter of 2008 compared to the fourth quarter of 2007 and 92% compared to the first quarter of 2007. Gas processed per day increased 2% and 38% over the fourth quarter of 2007 and the first quarter of 2007, respectively. In 2007, we upgraded several of our existing processing facilities and added three processing plants which was the primary reason for increased volumes. Gas gathered per day decreased 6% in the first quarter of 2008 compared to the fourth quarter of 2007 and 11% compared to the first quarter of 2007 primarily from our Southeast Oklahoma gathering system due to natural production declines associated with connected wells and the shutdown of a third-party processing plant in another location in February for approximately 10 days. Liquids prices in the first quarter of 2008 increased 6% over the price received in the fourth quarter of 2007 and 57% over the price received in the first quarter of 2007. The price of liquids as compared to natural gas affects the revenue in our mid-stream operations and determines the fractionation spread which is the difference in the value received for the NGLs recovered from natural gas in comparison to the amount received for the equivalent MMBtu's of natural gas if unprocessed. We have hedged 47% of our current fractional spread volumes to help manage our cash flow from this segment in 2008. Direct profit (mid-stream revenues less mid-stream operating expense) increased 37% from the fourth quarter of 2007 and 180% from the first quarter of 2007 primarily from the combination of both increased commodity prices and volumes processed and sold. Total operating cost for our mid-stream segment increased 8% from the fourth quarter of 2007 and 28% from the first quarter of 2007. As operators are encouraged to drill more wells while commodity prices are strong, we anticipate this will result in opportunity for growth in 2008. Wells being connected to existing gathering systems and the opportunity to build more gathering systems should increase in the later part of 2008 and into 2009.

Financial Condition and Liquidity

Summary. Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our bank credit facility. Our cash flow is influenced mainly by:

- 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 natural gas production and, to a lesser extent, the prices we receive for our oil and NGL 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, 2008 and 2007 and for the three months ended March 31, 2008 and 2007:

	March 31,				%
		2008		2007	Change
	(In thousands except percentages)				
Working capital	$	36,095	$	47,292	(24)%
Long-term debt	$	116,600	$	152,000	(23)%
Shareholders' equity	$	1,496,981	$	1,225,651	22%
Ratio of long-term debt to total capitalization		7.2%		11.0%	(35)%
Net income	$	77,064	$	64,482	20%
Net cash provided by operating activities	$	158,790	$	128,706	23%
Net cash used in investing activities	$	(158,768)	$	(111,251)	43%
Net cash used in financing activities	$	(250)	$	(17,441)	(99)%

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The following table summarizes certain operating information:

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	100.6	96.8	4%
Total number of drilling rigs owned at the end of the period	129	118	9%
Average dayrate	$ 17,997	$ 19,427	(7)%
Oil and Natural Gas:			
Oil production (MBbls)	292	232	26%
Natural gas liquids production (MBbls)	306	124	147%
Natural gas production (MMcf)	11,161	10,673	5%
Average oil price per barrel received	$ 93.32	$ 55.13	69%
Average oil price per barrel received excluding hedges	$ 96.25	$ 55.13	75%
Average NGL price per barrel received	$ 52.04	$ 33.43	56%
Average NGL price per barrel received excluding hedges	$ 51.49	$ 33.43	54%
Average natural gas price per mcf received	$ 7.65	$ 6.37	20%
Average natural gas price per mcf received excluding hedges	$ 7.60	$ 6.36	19%
Mid-Stream:			
Gas gathered—MMBtu/day	200,697	226,081	(11)%
Gas processed—MMBtu/day	59,797	43,327	38%
Gas liquids sold — gallons/day	183,924	95,964	92%
Number of natural gas gathering systems	36	37	(3)%
Number of processing plants	8	7	14%

At March 31, 2008, we had unrestricted cash totaling $0.8 million and we had borrowed $116.6 million of the $275.0 million we had elected to have available under our bank credit facility. Our bank credit facility is used for working capital and capital expenditures. Most of our capital expenditures are discretionary and directed toward future growth.

Working Capital. Our working capital balance fluctuates primarily as a result of the timing of our accounts receivable and accounts payable. We had working capital of $36.1 million and $47.3 million as of March 31, 2008 and 2007, respectively.

Contract Drilling. Our drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our drilling rigs and our ability to supply the equipment needed.

Competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future requirements of the drilling industry remains strong; therefore, we anticipate labor costs per hour to remain at current levels. If current demand for drilling rigs strengthens above the first quarter 2008 levels of 78%, shortages of experienced personnel would affect our ability to operate additional drilling rigs.

Most of our drilling rig fleet is used to drill natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we charge for our contract drilling services. As natural gas prices declined late in 2006 and the first part of 2007, demand for drilling rigs also declined. As a result, dayrates throughout the industry have declined to maintain rig utilization levels. For the first three months of 2008, our average dayrate was $17,997 per day compared to $19,427 per day for the first three months of 2007. The average number of our drilling rigs used in the first quarter of 2008 was 100.6 drilling rigs (78%) compared with 96.8 drilling rigs (83%) in the first quarter of 2007. Based on the average utilization of our drilling rigs during the first quarter of 2008, a $100 per day change in dayrates has a $10,060 per day ($3.7 million annualized) change in our pre-tax operating cash flow. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas, the levels of natural gas storage and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services contain the same terms and rates as the contracts we use with unrelated third parties for comparable type projects. During the first quarter of 2008 and 2007, we drilled 34 and 17 wells, respectively, for our exploration and production subsidiary. The profit associated with these wells received by our contract drilling segment of $7.5 million and $4.5 million, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Impact of Prices for Our Oil, NGLs and Natural Gas. As of December 31, 2007, natural gas comprised 82% of our oil, NGLs and natural gas reserves. Any significant change in natural gas prices has a material affect on our revenues, cash flow and the value of our oil, liquids and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our first quarter 2008 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 $349,000 per month ($4.2 million annualized) change in our pre-tax operating cash flow. Our first quarter 2008 average natural gas price received was $7.65 compared to an average natural gas price of $6.37 for the first quarter of 2007. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $92,000 per month ($1.1 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 $95,000 per month ($1.1 million annualized) change in our pre-tax operating cash flow based on our production in the first quarter of 2008. Our first quarter 2008 average oil price per barrel received was $93.32 compared with an average oil price of $55.13 in the first quarter of 2007 and our first quarter 2008 average NGLs price per barrel received was $52.04 compared with an average NGL price of $33.43 in the first quarter of 2007.

Because natural gas prices have such a significant affect on the value of our oil, NGLs and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our bank 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.

Most of our natural gas production is sold to third parties under month-to-month contracts.

Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. Superior is a mid-stream company engaged primarily in the buying and selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, eight processing plants, 36 gathering systems and 697 miles of pipeline. This subsidiary enhances our ability to gather and market not only our own natural gas but also that owned by third parties and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During the first quarter of 2008 and 2007, Superior purchased $11.3 million and $1.9 million, respectively of our natural gas production and natural gas liquids and provided gathering and transportation services of $1.1 million and $1.3 million, respectively. The increase in natural gas production and natural gas liquids purchased was primarily due to a purchasing agreement entered into between Superior and Unit Petroleum in the second quarter of 2007, relating to production in the Texas panhandle. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas exploration operations has been eliminated in our consolidated condensed financial statements.

Superior gathered 200,697 MMBtu per day in the first quarter of 2008 compared to 226,081 MMBtu per day in the first quarter of 2007, processed 59,797 MMBtu per day in the first quarter of 2008 compared to 43,327 MMBtu per day in the first quarter of 2007 and sold NGLs of 183,924 gallons per day in the first quarter of 2008 compared to 95,964 gallons per day in the first quarter of 2007. Gas gathering volumes per day in 2008 decreased 11% compared to 2007 primarily due to a volumetric decline in our Southeast Oklahoma gathering system due to natural production declines associated with the connected wells and the shutdown of a third-party processing plant in another location in February for approximately 10 days. Volumes processed increased 38% over the comparative quarters and NGLs sold increased 92% over the comparative quarters due to the addition of three natural gas processing plants in 2007.

Our Credit Facility. Our current Credit Facility with a maximum credit amount of $400.0 million matures on May 24, 2012. Borrowings under the Credit Facility are limited to a commitment amount that we elect. As of March 31, 2008, the commitment amount was $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of our total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for the first quarter of 2008, which includes the effect of our interest rate swaps, was 5.4% compared to 6.1% for the first quarter of 2007. At March 31, 2008 and April 30, 2008, our borrowings were $116.6 million and $115.3 million, respectively.

The borrowing base under the Credit Facility is subject to redetermination on April 1 and October 1 of each year. The current borrowing base is $500.0 million. Each redetermination is based primarily on a percentage of the discounted future value of our oil, NGLs and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The company or the lenders may request a one time special redetermination of the borrowing base between each scheduled redeterminations. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility. The lenders' aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period the outstanding principal balance of the promissory note to which such LIBOR option applies may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under the LIBOR bear interest at the BOKF National Prime Rate payable at the end of each month and the principal borrowed may be paid anytime, in part or in whole, without premium or penalty. At March 31, 2008, all of the $116.6 million we had borrowed was subject to LIBOR.

The Credit Facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain very limited exceptions and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of our lenders.

The Credit Facility also requires that we have at the end of each quarter:

- a consolidated net worth of at least $900.0 million,
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1 and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

On March 31, 2008, we were in compliance with each of these covenants.

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Capital Requirements

Drilling Acquisitions and Capital Expenditures. During 2006, we purchased major components to be used in the construction of two new 1,500 horsepower drilling rigs. The first rig was placed into service in our Rocky Mountain division at the end of March 2007 and the second rig was placed into service in the second quarter of 2007. The combined capitalized cost of both drilling rigs was $19.4 million. On June 5, 2007, we completed the acquisition of Leonard Hudson Drilling Co., Inc., a privately owned drilling company operating primarily in the Texas Panhandle. The acquired company owned nine drilling rigs, a fleet of 11 trucks, and an office, shop and equipment yard. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Eight of the nine drilling rigs were operating under contracts on the acquisition date. The remaining drilling rig was refurbished and placed in service during March of 2008. Results of operations for the acquired company have been included in our statements of income beginning June 5, 2007. Total consideration paid for this acquisition was $38.5 million.

In 2007, our contract drilling segment recorded $220.4 million in capital expenditures including the effect of a $19.4 million deferred tax liability and $5.3 million in goodwill associated with the Leonard Hudson Drilling acquisition. For 2008, we anticipate capital expenditures for this segment will be approximately $119.0 million excluding acquisitions and have spent $39.5 million in capital expenditures as of March 31, 2008. We are constructing two new 1,500 horsepower, diesel electric drilling rigs. We anticipate placing these drilling rigs into service in our Rocky Mountain division during the second quarter of 2008. Also, we have plans to build two additional 1,500 horsepower, diesel electric drilling rigs anticipated to be placed into service during the fourth quarter of 2008.

We currently do not have a shortage of drill pipe and drilling equipment. At March 31, 2008, we had commitments to purchase approximately $14.5 million of drill pipe, drill collars and related equipment in 2008.

Oil and Natural Gas Acquisitions and Capital Expenditures. On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was $16.8 million which consisted of $15.8 million allocated to the reserves of the wells and $1.0 million allocated to the undeveloped leasehold. The production and reserves acquired in this purchase are included in our 2008 results.

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. Due to limited availability of acquisitions that met our economic criteria in 2007, we focused on our developmental drilling program. We completed drilling 57 gross wells (28.56 net wells) in the first three months of 2008 compared to 54 gross wells (22.95 net wells) in the first three months of 2007. Our first quarter 2008 total capital expenditures for oil and natural gas exploration, excluding a $0.5 million increase in the plugging liability, totaled $104.8 million. Currently we plan to participate in drilling an estimated 280 gross wells in 2008 and estimate our total capital expenditures for oil and natural gas exploration to be approximately $360.0 million, excluding acquisitions. Whether we are able to drill the full number of wells we are planning on drilling is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, prices for oil, NGLs and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners.

Mid-Stream Capital Expenditures. During the first quarter of 2008, the mid-stream segment incurred $8.1 million in capital expenditures as compared to $7.9 million in the first quarter of 2007. For 2008, we have budgeted capital expenditures of approximately $32.0 million. Our plan is to grow this segment through the construction of new facilities or acquisitions.

Contractual Commitments. At March 31, 2008, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Bank debt (1)	$ 138,787	$ 5,349	$ 10,699	$ 122,739	$ —
Retirement agreements (2)	565	550	15	—	—
Operating leases (3)	3,774	1,818	1,763	193	—
Drill pipe, drilling components and equipment purchases (4)	15,639	15,639	—	—	—
Total contractual obligations	$ 158,765	$ 23,356	$ 12,477	$ 122,932	$ —

(1) See previous discussion in MD&A regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated using our March 31, 2008 interest rate of 4.6% which includes the effect of the interest rate swaps.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $25,000 which started in July 2003 and continues through June 2009. In the first quarter of 2005, we recorded $0.7 million in additional employee benefit expense for the present value of a separation agreement made in connection with the retirement of John Nikkel from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $31,250 which started in November 2006 and continuing through October 2008. These liabilities, as presented above, are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston and Midland, Texas; Pittsburgh, Pennsylvania and Denver, Colorado under the terms of operating leases expiring through January 31, 2012. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(4) For 2008, we have committed to purchase approximately $14.5 million of drill pipe, drill collars and related equipment and $1.1 million of tubing.

At March 31, 2008, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Accrued	Estimated Amount of Commitment Expiration Per Period Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred compensation plan (1)	$ 2,856	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 5,300	$ 72	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$ 32,744	$ 26,418	6,326	—	$ —
Derivative liabilities – interest rate swaps	$ 1,515	$ 343	686	486	$ —
Plugging liability (3)	$ 34,085	$ 710	$ 6,857	$ 2,562	$ 23,956
Gas balancing liability (4)	$ 3,364	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$ 22,717	$ 8,539	$ 3,974	$ 1,394	$ 8,810

(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 Consolidated Balance Sheet, 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 any 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. At March 31, 2008, there were 31 eligible employees to participate in the Special Plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143 (FAS 143), "Accounting for Asset Retirement Obligations," we have recorded 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 2008, 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.

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

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Hedging Activities. Periodically we enter into hedge transactions covering part of the interest we incur under our bank credit facility as well as the prices to be received for a portion of our future oil, NGLs and natural gas production.

Interest Rate Swaps. We enter into interest rate swaps to help manage our exposure to possible future interest rate increases under our bank credit facility. As of March 31, 2008, we had two outstanding interest rate swaps which were cash flow hedges. There was no material amount of ineffectiveness. The fair value of these swaps was recognized on the March 31, 2008 balance sheet as current and non-current derivative assets and liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
		($ in thousands)		
December 2007 – May 2012	$ 15,000	4.53%	3 month LIBOR	$ (868)
December 2007 – May 2012	$ 15,000	4.16%	3 month LIBOR	(647)
				$ (1,515)

As a result of these interest rate swaps, interest expense decreased by $0.1 million for the three months ended March 31, 2008. A loss of $0.9 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of March 31, 2008. During the first quarter of 2007, we had an outstanding interest rate swap covering $50.0 million of our bank debt which swapped a variable interest rate for a fixed rate. As a result of that swap, our interest expense decreased by $0.2 million for the three months ended March 31, 2007.

Commodity Hedges. We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our products is based in part on our view of current and future market conditions. For 2008, in an attempt to better manage our cash flows, we have increased the amount of our hedged production. As of April 15, 2008, the below approximated percentages of our current production has been hedged:

Oil and Natural Gas Segment:

	Apr'08	Apr – Dec'08
Monthly NGL production	29%	—%
Daily oil production	72%	72%
Daily natural gas production	40%	40%

Mid-Stream Segment:

	Apr'08	May – Jul'08	Aug – Dec'08
Full stream fractionation spread	65%	—%	—%
Ethane frac spread	—%	70%	29%
Propane frac spread	—%	71%	46%
Iso-butane frac spread	—%	62%	24%
Normal butane frac spread	—%	62%	24%
Gasoline frac spread	—%	48%	24%

As of April 15, 2008, approximately 16% of our current daily natural gas production in our oil and gas segment is hedged for the period January through December 2009.

While the use of hedging arrangements limits the downside risk of adverse price movements, it also may limit increases in our future revenues from favorable price movements.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. At April 30, 2008, Bank of Montreal, Bank of Oklahoma, N.A. and Bank of America, N.A. were the counterparties with respect to all of our commodity hedging transactions. At March 31, 2008, the fair values of the net liabilities we had with each of these counterparties was $16.5 million, $8.5 million and $7.6 million, respectively.

Currently all of our commodity hedges are cash flow hedges and there is no material amount of ineffectiveness. At March 31, 2008, we recorded the fair value of our commodity hedges on our balance sheet as current derivative assets of $0.1 million and current and non-current derivative liabilities of $32.7 million. During the first quarter of 2007, we had one collar for 10,000 MMBtus/day covering the periods of January through December of 2007 and two collars for 10,000 MMBtus/day each covering the periods of March through December 2007. These collars contained prices ranging from a floor of $6.00 to a ceiling of $10.00. At March 31, 2007, we had current derivative assets of $0.5 million and current derivative liabilities of $1.2 million.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2008, we had a loss of $20.9 million, net of tax, from our oil and natural gas segment derivatives and a gain of $0.3 million, net of tax, from our mid-stream segment derivatives in accumulated other comprehensive income (loss). At March 31, 2008, commodity instruments with a net fair value liability of $26.3 million were short-term and will be settled into earnings within twelve months. Realized gains and losses from our commodity derivative settlements included in revenues and expenses were as follows for the three months ended March 31:

	2008	2007
	(In thousands)	
Increases (decreases) in:		
Oil and natural gas revenue	$ (112)	$ 152
Gas gathering and processing revenue	(119)	—
Gas gathering and processing expense	(182)	—
Impact on pre-tax earnings	$ (49)	$ 152

Stock and Incentive Compensation. During the first quarter of 2008, we granted awards covering 14,500 shares of restricted stock. These awards were granted as retention incentive awards. During the first quarter of 2008, we recognized compensation expense of $2.5 million for all of our restricted stock, stock options and SAR grants and capitalized $0.8 million of compensation cost for oil and natural gas properties. The first quarter 2008 restricted stock awards had an estimated fair value as of the grant date of $0.6 million. Compensation expense will be recognized over the three year vesting periods, and during the first quarter of 2008, we recognized less than $0.1 million in additional compensation expense and capitalized less than $0.1 million for these awards.

Self-Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.25 million for Oklahoma workers' compensation, as well as claims under our occupation benefits plan to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. If our insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. We have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas in lieu of covering them under Texas workers' compensation.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships.   We are the general partner of 13 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

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parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. During 2007, and the first quarter of 2008, the total we received for all of these fees was $1.6 million and $0.5 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

New Accounting Pronouncements

Fair Value Measurements. In September 2006, the FASB issued Statement No. 157 (FAS 157), "Fair Value Measurements," which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied FAS 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of FAS 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of FAS 157 to our financial instruments and the impact was not material. Under FSP 157-2, we will be required to apply FAS 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We are currently reviewing the applicability of FAS 157 to our nonfinancial assets and liabilities and the potential impact that application will have on our consolidated financial statements.

In February 2007, the FASB issued Statement No. 159 (FAS 159), "The Fair Value Option for Financial Assets and Financial Liabilities," which allows companies to elect to measure specified financial assets and liabilities, firm commitments and non-financial warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. At January 1, 2008, we did not elect the fair value option under FAS 159 and therefore there was no impact on our consolidated financial statements.

Business Combinations. In December 2007, the FASB issued Statement No. 141R (FAS 141R), "Business Combinations," which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. FAS 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of FAS 141R to our operations and its potential impact on our consolidated financial statements.

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), "Noncontrolling Interest in Consolidated Financial Statements – an amendment to ARB No. 51," which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. We are currently reviewing the applicability of FAS 160 to our operations and its potential impact on our consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued Statement No. 161 (FAS 161), "Disclosures about Derivative Instruments and Hedging Activities - an Amendment of FASB Statement 133," which requires enhanced disclosures about how derivative and hedging activities affect our financial position, financial performance and cash flows. FAS 161 is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of FAS 161 to our consolidated financial statement disclosures.

Results of Operations

Quarter Ended March 31, 2008 versus Quarter Ended March 31, 2007

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

	Quarter Ended March 31, 2008	Quarter Ended March 31, 2007	Percent Change
Total revenue	$ 321,362,000	$ 277,271,000	16%
Net income	$ 77,064,000	$ 64,482,000	20%
Contract Drilling:			
Revenue	$ 147,247,000	$ 160,285,000	(8)%
Operating costs excluding depreciation	$ 74,461,000	$ 76,287,000	(2)%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	100.6	96.8	4%
Average dayrate on daywork contracts	$ 17,997	$ 19,427	(7)%
Depreciation	$ 15,364,000	$ 12,717,000	21%
Oil and Natural Gas:			
Revenue	$ 130,002,000	$ 86,106,000	51%
Operating costs excluding depreciation, depletion and amortization	$ 27,601,000	$ 22,139,000	25%
Average oil price (Bbl)	$ 93.32	$ 55.13	69%
Average NGL price (Bbl)	$ 52.04	$ 33.43	56%
Average natural gas price (Mcf)	$ 7.65	$ 6.37	20%
Oil production (Bbl)	292,000	232,000	26%
NGL production (Bbl)	306,000	124,000	147%
Natural gas production (Mcf)	11,161,000	10,673,000	5%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.41	$ 2.28	6%
Depreciation, depletion and amortization	$ 35,715,000	$ 29,347,000	22%
Mid-Stream Operations:			
Revenue	$ 44,223,000	$ 30,768,000	44%
Operating costs excluding depreciation and amortization	$ 35,072,000	$ 27,501,000	28%
Depreciation and amortization	$ 3,481,000	$ 2,339,000	49%
Gas gathered—MMBtu/day	200,697	226,081	(11)%
Gas processed—MMBtu/day	59,797	43,327	38%
Gas liquids sold—gallons/day	183,924	95,964	92%
General and administrative expense	$ 6,525,000	$ 5,182,000	26%
Interest expense	$ 820,000	$ 1,641,000	(50)%
Income tax expense	$ 45,259,000	$ 35,636,000	27%
Average interest rate	5.4%	6.1%	(11)%
Average long-term debt outstanding	$ 137,995,000	$ 164,451,000	(16)%

Contract Drilling:

Drilling revenues decreased $13.0 million or 8% in the first three months of 2008 versus the first three months of 2007 primarily due to decreases in dayrates between the comparative quarters. As natural gas prices declined late in 2006 and the first part of 2007, demand for drilling rigs also declined. As a result, dayrates throughout the industry have declined to maintain rig utilization levels. Our average dayrate in the first quarter of 2008 was 7% lower than in the first quarter of 2007. Decreases in revenue per day between the comparative periods decreased revenue by $21.2 million. This decrease was partially offset by an $8.2 million increase in revenues from additional rigs in use. Average rig utilization increased from 96.8 drilling rigs in the first quarter of 2007 to 100.6 in the first quarter of 2008. We anticipate average dayrates to slightly decline into the second quarter of 2008, with our utilization rate remaining at approximately 80%. In the first quarter of 2008, commodity prices increased significantly and should commodity prices remain strong, we anticipate increases in both utilization percentages and dayrates later in the year as medium depth range drilling rigs industry-wide become more fully utilized.

Drilling operating costs decreased $1.8 million or 2% between the comparative first quarters of 2008 and 2007 primarily due to the drilling of 34 wells for our oil and natural gas segment in the first quarter of 2008 compared to 17 wells drilled in the first quarter of 2007 which increased our intercompany elimination along with a reduction in the average direct cost per day. These decreases were offset by increased expense resulting from the additional yard, trucks and autos associated with our June 2007 rig acquisition and an additional 3.9 rigs working during the first quarter of 2008. With continued competition for qualified labor and utilization continuing around 80%, we expect our drilling rig expense per day to remain steady or increase slightly in 2008. Contract drilling depreciation increased $2.6 million or 21% as the total number of drilling rigs owned increased between the comparative periods.

Oil and Natural Gas:

Oil and natural gas revenues increased $43.9 million or 51% in the first three months of 2008 as compared to the first three months of 2007 due to an increase in equivalent production volumes of 15% and an increase in average oil, NGL and natural gas prices. Average oil prices between the comparative quarters increased 69% to $93.32 per barrel, NGL prices increased 56% to $52.04 per barrel and natural gas prices increased 20% to $7.65 per Mcf. In the first quarter of 2008 compared to the first quarter of 2007, oil production increased 26%, NGL production increased 147% and natural gas production increased 5%. Increased production came primarily from our ongoing development drilling activity. In addition, there was a decrease in production during the first quarter of 2008 due to a third-party processing plant being shut down and in the first quarter of 2007 primarily due to a refinery fire. With the continuation of our internal drilling program, our total production for 2008 compared to 2007 is anticipated to increase 8% to 11%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $5.5 million or 25% between the comparative first quarters of 2008 and 2007. An increase in the average cost per equivalent Mcf produced represented 35% of the increase in operating costs with the remaining 65% of the increase attributable to the increase in volumes produced as we continue to add wells from development drilling. Increases in general and administrative expenses directly related to oil and natural gas production and gross production taxes from higher revenues contributed to the majority of the operating cost increase. General and administrative expenses increased as labor costs increased primarily due to a 20% increase in the average number of employees working in the exploration and production area while lease operating expenses increased primarily due to an increase in the number of wells drilled and also from increases in the cost of goods purchased and services provided. Gross production taxes increased primarily as a result of the increase in oil and natural gas revenues. Total depreciation, depletion and amortization ("DD&A") increased $6.4 million or 22%. Higher production volumes accounted for 70% of the increase while increases in our DD&A rate represented 30% of the increase. The increase in our DD&A rate in the first quarter of 2008 compared to the first quarter of 2007 resulted primarily from increases in the cost of Mcf equivalents added to our reserves in 2007 and the first quarter of 2008 as compared to the average cost of Mcf equivalents added prior to the first quarter of 2007. The increase in commodity prices over the last two years has increased the cost of acquiring producing properties. Even with the increase in acquisition costs we continue to see strong competition for producing property acquisitions.

Mid-Stream:

Our mid-stream revenues were $13.5 million or 44% higher for the first three months of 2008 as compared to the first three months of 2007 due to the higher NGL volumes sold and processed volumes combined with higher NGL and natural gas prices. The average price for NGLs sold increased 56% and the average price for natural gas sold increased 17%. Gas processing volumes per day increased 38% between the comparative quarters and NGLs sold per day increased 92% between the comparative quarters. An 11% decrease in gathering volumes per day partially offset the increase in revenue from natural gas liquids and processing sales. The significant increase in volumes processed per day is primarily attributable to the installation of three processing plants in 2007, and to a lesser extent, volumes added from new wells connected to existing systems throughout 2007. NGLs sold volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes decreased

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primarily from a decline in volumes gathered from our Southeast Oklahoma gathering system due to natural declines of production in the formation and the shutdown of a third-party processing plant in another location in February for approximately 10 days. NGL sales were reduced $0.1 million due to the impact of NGL hedges in the first quarter of 2008.

Operating costs increased $7.6 million or 28% in the first quarter of 2008 compared to the first quarter of 2007 due to a 28% increase in natural gas volumes purchased per day and a 24% increase in prices paid for natural gas purchased, a 21% increase in field direct operating cost due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and a 77% increase in general and administrative expenses associated with our mid-stream segment. The total number of employees working in our mid-stream segment increased by 18%. Depreciation and amortization increased $1.1 million, or 49%, primarily attributable to the additional depreciation associated with assets acquired between the comparative periods. Operating costs were reduced by $0.2 million in the first quarter of 2008 compared to the first quarter of 2007 due to the impact of natural gas purchase hedges.

Other:

General and administrative expense increased $1.3 million or 26% in the first quarter of 2008 compared to the first quarter of 2007. The increase was primarily attributable to increased stock based compensation costs and increased payroll expenses due to a 10% increase in the number of employees added.

Total interest expense decreased $0.8 million or 50% between the comparative quarters. Lower average debt outstanding was 16% lower in the first quarter of 2008 as compared to the first quarter of 2007 as we paid down debt in 2007 after the acquisition of producing properties acquired in the last four months of 2006. Average debt outstanding accounted for approximately 65% of the interest expense decrease, with the remaining 35% resulting from a decrease in average interest rates on our bank debt. Interest expense was reduced $0.1 million in the first three months of 2008 and $0.2 million in the first three months of 2007 from settlements on our interest rate swaps. Associated with our increased level of undeveloped inventory of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $1.2 million of interest in the first quarter of 2008 compared to $1.0 million in the first quarter of 2007.

Income tax expense increased $9.6 million or 27% due primarily to the increase in income before income taxes. Our effective tax rate for the first quarter of 2008 was 37% versus 35.6% for the first quarter of 2007 with the change due primarily to the decrease in manufacturing tax deduction for 2008. The portion of our taxes reflected as current income tax expense for the first quarter of 2008 was $15.4 million or 34% of total income tax expense in 2008 as compared with $22.7 million or 64% of total income tax expense in the first quarter of 2007. The reduction in the percentage of tax expense recognized as current is the result of expected bonus depreciation on equipment and increased intangible drilling costs to be deducted in the current year. Income taxes paid in the first quarter of 2008 were $0.3 million.

Safe Harbor Statement

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

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

- the amount and nature of our future capital expenditures;
- the amount of wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- our exploration prospects;
- estimates of our proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas reserves;
- growth potential for our mid-stream operations;
- 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; and
- demand for our drilling rigs and drilling rig rates.

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

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations; 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 as a result 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 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 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 quarter 2008 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 $349,000 per month ($4.2 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 an

$92,000 per month ($1.1 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 $95,000 per month ($1.1 million annualized) change in our pre-tax operating cash flow.

We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our products is based in part on our view of current and future market conditions. For 2008, in an attempt to better manage our cash flows, we have increased the amount of our hedged production through various financial transactions that hedge the future prices received. These transactions include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we will settle the difference with the counterparty to the collars. These financial hedging activities are intended to support oil and gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

At March 31, 2008, we had the following cash flow hedges outstanding:

Oil and Natural Gas Segment:

Term	Sell/ Purch.	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Market
Apr'08	Sell	Liquids – swap (1)	582,000 Gal/mo	$1.16	OPIS - Conway
Apr'08	Sell	Liquids – swap (1)	750,000 Gal/mo	$1.11	OPIS – Mont Belvieu
Apr – Dec'08	Sell	Crude oil – swap	1,000 Bbl/day	$91.32	WTI - NYMEX
Apr – Dec'08	Sell	Crude oil - collar	1,000 Bbl/day	$85.00 put & $98.75 call	WTI - NYMEX
Apr – Dec'08	Sell	Crude oil - collar	500 Bbl/day	$90.00 put & $102.50 call	WTI - NYMEX
Apr – Dec'08	Sell	Natural gas – swap	20,000 MMBtu/day	$7.52	IF – Centerpoint East
Apr – Dec'08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.00 put & $8.40 call	IF – Centerpoint East
Apr – Dec'08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.20 put & $8.80 call	IF – Tenn (Zone 0)
Apr – Dec'08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.50 put & $8.70 call	NGPL-TXOK
Jan – Dec'09	Sell	Natural gas – swap	10,000 MMBtu/day	$7.77	IF – Centerpoint East
Jan – Dec'09	Sell	Natural gas – swap	10,000 MMBtu/day	$8.28	IF – Tenn (Zone 0)

(1) Types of liquids involved are ethane and propane.

Mid-Stream Segment:

Term	Commodity	Market

	Sell/ Purchase		Hedged Volume	Weighted Average Fixed Price	
Apr’08	Sell	Liquids – swap (1)	1,836,000 Gal/mo	$ 1.34	OPIS - Conway
Apr’08	Purchase	Natural gas – swap	171,000 MMBtu/mo	$ 6.46	IF - PEPL
May – Jul’08	Sell	Liquids – swap (1)	1,330,000 Gal/mo	$ 1.27	OPIS - Conway
May – Jul’08	Purchase	Natural gas – swap	116,300 MMBtu/mo	$ 6.93	IF - PEPL
Aug – Dec’08	Sell	Liquid – swap (2)	188,000 Gal/mo	$ 1.43	OPIS - Conway
Aug – Dec’08	Purchase	Natural gas – swap	17,000 MMBtu/mo	$ 6.91	IF - PEPL

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and natural butane.
(2) Type of liquid involved is propane.

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After March 31, 2008, we entered into the following cash flow hedges:

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Weighted Average Fixed Price	Market
May – Dec'08	Sell	Liquids – swap (1)	507,020 Gal/mo	$ 1.41	OPIS - Conway
May – Jul'08	Purchase	Natural gas – swap	43,175 MMBtu/mo	$ 9.41	IF - PEPL
Aug – Dec'08	Sell	Liquid – swap (2)	217,400 Gal/mo	$ 1.68	OPIS - Conway
Aug – Dec'08	Purchase	Natural gas – swap	63,090 MMBtu/mo	$ 9.55	IF - PEPL

(1) Types of liquids involved are natural gasoline, ethane, isobutane and natural butane.
(2) Type of liquid involved is propane.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. To help manage our exposure to any future interest rate volatility, we currently have two $15.0 million interest rate swaps, one at a fixed rate of 4.53% and one at a fixed rate of 4.16%, both expiring in May 2012. Based on our average outstanding long-term debt subject to the floating rate in the first three months of 2008, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $1.1 million.

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, 2008 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, 2008 that could significantly affect these internal controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The company is a party to certain litigation arising in the ordinary course of its business. Although the amount of any liability that could arise with respect to these actions cannot be accurately predicted, in the company's opinion, any such liability will not have a material adverse effect on our business, financial condition and/or operating results.

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2007, 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, 2007.

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 first quarter of 2008:

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, 2008 to January 31, 2008	6,037	$ 46.25	6,037	—
February 1, 2008 to February 29, 2008	—	—	—	—
March 1, 2008 to March 31, 2008	—	—	—	—
Total	6,037	$ 46.25	6,037	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the January 1, 2008 vesting distribution for grants previously made from our “Unit Corporation Stock and Incentive Compensation Plan” (2,794 shares) adopted May 3, 2006 and our “Employee Stock Bonus Plan” (3,243 shares) adopted December 1984 and terminated for the purpose of future grants on 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. Submission of Matters to a Vote of Security Holders

Not applicable

Item 5. Other Information

Not applicable

Item 6. Exhibits

Exhibits:

15 Letter re: Unaudited Interim Financial Information.

31.1 Certification of Chief Executive Officer under Rule 13a – 14(a) of the
Exchange Act.

31.2 Certification of Chief Financial Officer under Rule 13a – 14(a) of the
Exchange Act.

32 Certification of Chief Executive Officer and Chief Financial Officer under
Rule 13a – 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted
under Section 906 of the Sarbanes-Oxley Act of 2002.

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 6, 2008	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: May 6, 2008	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer