**SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**

# Form 10-Q

**[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)**
**OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended June 30, 2007**

**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, or a non-accelerated filer.

Large accelerated filer [x]    Accelerated filer [ ]    Non-accelerated filer [ ]

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

Yes [ ]    No [x]

As of July 31, 2007, 46,430,960 shares of the issuer's common stock were outstanding.

# FORM 10-Q
# UNIT CORPORATION

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## PART I. FINANCIAL INFORMATION

**Item 1. Financial Statements**

### UNIT CORPORATION AND SUBSIDIARIES
### CONSOLIDATED CONDENSED BALANCE SHEETS (UNAUDITED)

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (In thousands) | |
| **ASSETS** | | |
| Current Assets: | | |
| Cash and cash equivalents | $ 578 | $ 589 |
| Restricted cash | 19 | 18 |
| Accounts receivable | 205,578 | 200,415 |
| Materials and supplies | 18,997 | 18,901 |
| Other | 12,209 | 13,017 |
| Total current assets | 237,381 | 232,940 |
| Property and Equipment: | | |
| Drilling equipment | 914,646 | 781,190 |
| Oil and natural gas properties, on the full cost method: | | |
| Proved properties | 1,455,960 | 1,330,010 |
| Undeveloped leasehold not being amortized | 61,039 | 53,687 |
| Gas gathering and processing equipment | 103,351 | 85,339 |
| Transportation equipment | 22,808 | 20,749 |
| Other | 19,270 | 17,082 |
| | 2,577,074 | 2,288,057 |
| Less accumulated depreciation, depletion, amortization and impairment | 825,820 | 735,394 |
| Net property and equipment | 1,751,254 | 1,552,663 |
| Goodwill | 63,071 | 57,524 |
| Other Intangible Assets, Net | 15,782 | 17,087 |
| Other Assets | 14,108 | 13,882 |
| Total Assets | $ 2,081,596 | $ 1,874,096 |

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

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

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (In thousands) | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| Current Liabilities: | | |
| Accounts payable | $ 90,705 | $ 92,125 |
| Accrued liabilities | 39,151 | 52,166 |
| Income taxes payable | 3,220 | 2,956 |
| Contract advances | 6,533 | 5,061 |
| Current portion of other liabilities | 10,461 | 8,634 |
| Total current liabilities | 150,070 | 160,942 |
| Long-Term Debt | 209,800 | 174,300 |
| Other Long-Term Liabilities | 55,428 | 55,741 |
| Deferred Income Taxes | 373,258 | 325,077 |
| 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, 46,424,360 and 46,283,990 shares issued, respectively | 9,279 | 9,257 |
| Capital in excess of par value | 339,992 | 333,833 |
| Accumulated other comprehensive income | 114 | 1,339 |
| Retained earnings | 943,655 | 813,607 |
| Total shareholders' equity | 1,293,040 | 1,158,036 |
| Total Liabilities and Shareholders' Equity | $ 2,081,596 | $ 1,874,096 |

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

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

| | Three Months Ended June 30, 2007 | Three Months Ended June 30, 2006 | Six Months Ended June 30, 2007 | Six Months Ended June 30, 2006 |
|---|---|---|---|---|
| | (In thousands except per share amounts) | | | |
| Revenues: | | | | |
| Contract drilling | $ 154,349 | $ 175,908 | $ 314,634 | $ 337,338 |
| Oil and natural gas | 96,343 | 81,954 | 182,449 | 176,280 |
| Gas gathering and processing | 35,769 | 21,720 | 66,537 | 47,202 |
| Other | 179 | 767 | 291 | 2,337 |
| Total revenues | 286,640 | 280,349 | 563,911 | 563,157 |
| Expenses: | | | | |
| Contract drilling: | | | | |
| Operating costs | 74,729 | 79,117 | 151,016 | 159,426 |
| Depreciation | 13,682 | 12,845 | 26,399 | 24,686 |
| Oil and natural gas: | | | | |
| Operating costs | 24,461 | 18,988 | 46,600 | 37,294 |
| Depreciation, depletion and amortization | 30,723 | 25,041 | 60,070 | 49,223 |
| Gas gathering and processing: | | | | |
| Operating costs | 31,395 | 18,717 | 58,896 | 41,518 |
| Depreciation and amortization | 2,555 | 1,232 | 4,894 | 2,382 |
| General and administrative | 5,247 | 4,402 | 10,429 | 8,368 |
| Interest | 1,729 | 1,017 | 3,370 | 2,007 |
| Total expenses | 184,521 | 161,359 | 361,674 | 324,904 |
| Income Before Income Taxes | 102,119 | 118,990 | 202,237 | 238,253 |
| Income Tax Expense: | | | | |
| Current | 19,649 | 33,141 | 42,346 | 63,299 |
| Deferred | 16,904 | 11,032 | 29,843 | 25,224 |
| Total income taxes | 36,553 | 44,173 | 72,189 | 88,523 |
| Net Income | $ 65,566 | $ 74,817 | $ 130,048 | $ 149,730 |
| Net Income per Common Share: | | | | |
| Basic | $ 1.41 | $ 1.62 | $ 2.81 | $ 3.24 |
| Diluted | $ 1.41 | $ 1.61 | $ 2.79 | $ 3.23 |

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

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

| | Six Months Ended June 30, 2007 | 2006 |
|---|---|---|
| | (In thousands) | |
| Cash Flows From Operating Activities: | | |
| Net income | $ 130,048 | $ 149,730 |
| Adjustments to reconcile net income to net cash provided (used) by operating activities: | | |
| Depreciation, depletion and amortization | 91,807 | 76,640 |
| Deferred tax expense | 29,843 | 25,224 |
| Other | 5,080 | 3,566 |
| Changes in operating assets and liabilities increasing (decreasing) cash: | | |
| Accounts receivable | (5,163) | 7,650 |
| Accounts payable | (22,029) | (30,993) |
| Material and supplies inventory | (96) | (669) |
| Accrued liabilities | (12,510) | (14,114) |
| Contract advances | 1,472 | 5,304 |
| Other – net | 900 | 1,147 |
| Net cash from operating activities | 219,352 | 223,485 |
| Cash Flows From (Used In) Investing Activities: | | |
| Capital expenditures (including producing property, drilling rig and other acquisitions) | (262,031) | (214,452) |
| Proceeds from disposition of assets | 3,279 | 3,795 |
| Other-net | (1) | 250 |
| Net cash used in investing activities | (258,753) | (210,407) |
| Cash Flows From (Used In) Financing Activities: | | |
| Borrowings under line of credit | 124,900 | 115,600 |
| Payments under line of credit | (89,400) | (130,900) |
| Proceeds from exercise of stock options | 605 | 654 |
| Book overdrafts | 3,285 | 1,422 |
| Net cash from (used in) financing activities | 39,390 | (13,224) |
| Net Decrease in Cash and Cash Equivalents | (11) | (146) |
| Cash and Cash Equivalents, Beginning of Period | 589 | 947 |
| Cash and Cash Equivalents, End of Period | $ 578 | $ 801 |

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

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

| | Three Months Ended June 30, 2007 | Three Months Ended June 30, 2006 | Six Months Ended June 30, 2007 | Six Months Ended June 30, 2006 |
|---|---|---|---|---|
| | (In thousands) | | | |
| Net Income | $ 65,566 | $ 74,817 | $ 130,048 | $ 149,730 |
| Other Comprehensive Income, Net of Taxes: | | | | |
| Change in value of derivative instruments used as cash flow hedges (net of tax of $363, $91, $(514) and $225) | 630 | 155 | (904) | 379 |
| Reclassification - Derivative settlements (net of tax of $(62), $(41), $(176) and $(70)) | (112) | (69) | (321) | (119) |
| Comprehensive Income | $ 66,084 | $ 74,903 | $ 128,823 | $ 149,990 |

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

## NOTE 1 - BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited consolidated condensed financial statements include the accounts of Unit Corporation and its directly or indirectly wholly owned subsidiaries (company) and have been prepared under the rules and regulations of the Securities and Exchange Commission (SEC). As applicable under these regulations, certain information and footnote disclosures have been condensed or omitted and the consolidated condensed financial statements do not include all disclosures required by accounting principles generally accepted in the United States of America. In the opinion of the company, the unaudited consolidated condensed financial statements contain all adjustments necessary (all adjustments are of a normal recurring nature) to state fairly the interim financial information.

Results for the three months and six months ended June 30, 2007 are not necessarily indicative of the results to be realized during the full year. The consolidated condensed financial statements should be read with the company's Annual Report on Form 10-K for the year ended December 31, 2006. With respect to the unaudited financial information for the three and six month periods ended June 30, 2007 and 2006 included in this Form 10-Q, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of that information. However, their Report dated August 2, 2007 which is included in this quarterly report, states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the reliance placed on their 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 their 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.

Before January 1, 2006, the company accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. Under APB 25, no stock-based employee compensation costs relating to stock options was not reflected in net income since all options granted under the company's plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, the company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment, (FAS 123(R)) to account for stock-based employee compensation. FAS 123(R) eliminated the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize in their financial statements the cost of employee services received in exchange for equity awards based on the grant date fair value of those awards. The company has elected to use the modified prospective method in applying FAS123(R), which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Financial statements for prior periods have not been restated. On adoption of FAS 123(R), the company 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 options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at 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 will be recognized in the financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and operating costs of the company's business segments. The company utilizes 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.

In the second quarter and first six months of 2007, the company recognized stock compensation expense for restricted stock awards, stock appreciation rights and stock options of $1.0 million and $1.6 million, respectively and capitalized stock compensation cost for oil and natural gas properties of $0.1 million and $0.2 million, respectively. The tax benefit related to this stock based compensation was $0.2 million and $0.4 million for the second quarter and first six months of 2007, respectively. In the second quarter and first six months of 2006, the company recognized stock compensation expense for restricted stock awards and stock options of $0.6 million and $1.3 million, respectively and capitalized stock compensation cost for oil and natural gas properties of $0.2 million and $0.4 million, respectively. The tax benefit related to this stock based compensation was $0.2 million and $0.5 million, respectively for the second quarter and first six months of 2006. The remaining unrecognized compensation cost related to unvested awards at June 30, 2007 is approximately $3.4 million with $0.6 million of this amount to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 years.

No stock appreciation rights were granted during the second quarters or first six months of 2007 and 2006.

The following table estimates the fair value of each option granted during the three and six month periods ending June 30, 2007 and 2006 using the Black-Scholes model applying the estimated values presented in the table:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| Options Granted | 28,000 | 33,000 | 28,000 | 33,000 |
| Estimated Fair Value (In Millions) | $ 0.6 | $ 0.8 | $ 0.6 | $ 0.8 |
| Estimate of Stock Volatility | 0.33 | 0.38 | 0.33 | 0.38 |
| Estimated Dividend Yield | ---% | ---% | ---% | ---% |
| Risk Free Interest Rate | 5.00% | 5.00% | 5.00% | 5.00% |
| Expected Life Based on Prior Experience (In Years) | 5 | 3 to 7 | 5 | 3 to 7 |

Expected volatilities are based on the historical volatility of the company's common stock. The company uses historical data to estimate option exercise and employee termination rates within the model and aggregates groups of employees that have similar historical exercise behavior for valuation purposes. The company has historically not paid dividends on its stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised. The stock options granted in the second quarter of 2007 increased stock compensation expense for the second quarter and first six months of 2007 by $0.2 million.

The following table shows the fair value of restricted stock awards granted during the three and six month periods ending June 30, 2007 and 2006:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| Shares Granted | 5,500 | --- | 5,500 | --- |
| Estimated Fair Value (In Millions) | $ 0.3 | $ --- | $ 0.3 | $ --- |
| Percentage of Shares Granted Expected to be Distributed | 95% | --- | 95% | --- |

The restricted stock awards granted in the second quarter of 2007 increased stock compensation expense for the second quarter and first six months of 2007 by $16,000.

## NOTE 2 - EARNINGS PER SHARE

Basic and diluted earnings per share for the three month periods indicated were computed as follows:

| | Income (Numerator) | Weighted Shares (Denominator) | Per-Share Amount |
|---|---|---|---|
| | (In thousands except per share amounts) | | |
| For the Three Months Ended June 30, 2007: | | | |
| Basic earnings per common share | $ 65,566 | 46,371 | $ 1.41 |
| Effect of dilutive stock options and restricted stock bonus shares | -- | 232 | -- |
| Diluted earnings per common share | $ 65,566 | 46,603 | $ 1.41 |
| For the Three Months Ended June 30, 2006: | | | |
| Basic earnings per common share | $ 74,817 | 46,228 | $ 1.62 |
| Effect of dilutive stock options | -- | 215 | (0.01) |
| Diluted earnings per common share | $ 74,817 | 46,443 | $ 1.61 |

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended June 30, 2007 and 2006 because the option exercise prices were greater than the average market price of the common stock:

| | 2007 | 2006 |
|---|---|---|
| Options | 29,500 | 29,500 |
| Average Exercise Price | $ 62.29 | $ 62.29 |

Basic and diluted earnings per share for the six month periods indicated were computed as follows:

| | Income (Numerator) | Weighted Shares (Denominator) | Per-Share Amount |
|---|---|---|---|
| | (In thousands except per share amounts) | | |
| For the Six Months Ended June 30, 2007: | | | |
| Basic earnings per common share | $ 130,048 | 46,350 | $ 2.81 |
| Effect of dilutive stock options and restricted stock bonus shares | -- | 223 | (0.02) |
| Diluted earnings per common share | $ 130,048 | 46,573 | $ 2.79 |
| For the Six Months Ended June 30, 2006: | | | |
| Basic earnings per common share | $ 149,730 | 46,214 | $ 3.24 |
| Effect of dilutive stock options | -- | 204 | (0.01) |
| Diluted earnings per common share | $ 149,730 | 46,418 | $ 3.23 |

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the six months ended June 30, 2007 and 2006 because the option exercise prices were greater than the average market price of the common stock:

| | 2007 | 2006 |
|---|---|---|
| Options | 61,000 | 29,500 |
| Average Exercise Price | $ 59.66 | $ 62.29 |

**NOTE 3 – ACQUISITION**

On June 5, 2007, the company's wholly owned subsidiary, Unit Drilling Company, completed the acquisition of a privately owned drilling company operating primarily in the Texas Panhandle. The acquisition included nine drilling rigs, drill pipe and collars, a fleet of 11 trucks, an office, shop, equipment yard and personnel. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Seven of the nine drilling rigs were operating on the acquisition date. One drilling rig is being refurbished and should be operational during the third quarter of 2007. Results of operations for the acquired company are included in the company's statement of income beginning June 5, 2007. The total purchase price paid in this acquisition (excluding working capital) was allocated as follow (in thousands):

| | | |
|---|---|---|
| Drilling Rigs | $ | 39,326 |
| Spare Drilling Equipment | | 1,613 |
| Drill Pipe and Collars | | 7,784 |
| Trucks | | 1,551 |
| Other Vehicles | | 190 |
| Yard and Office | | 846 |
| Goodwill | | 5,548 |
| Deferred Income Taxes | | (18,358) |
| Total Consideration | $ | 38,500 |

An additional settlement for working capital will be made in the third quarter of 2007. This settlement is not expected to be material.

**NOTE 4 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES**

As of June 30, 2007 and December 31, 2006, long-term debt consisted of the following:

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (In thousands) | |
| Revolving Credit Facility, with Interest at June 30, 2007 and December 31, 2006 of 6.5% and 6.4%, Respectively | $ 209,800 | $ 174,300 |
| Less Current Portion | --- | --- |
| Total Long-Term Debt | $ 209,800 | $ 174,300 |

On May 24, 2007, the company 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 elected by the company. As of June 30, 2007, the current commitment amount was $275.0 million. The company is 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. The company incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility. These fees are being amortized over the remaining life of the agreement. The average interest rate for the second quarter and first six months of 2007 was 6.5%. At June 30, 2007 and July 31, 2007, borrowings were $209.8 million and $197.8 million, respectively.

The borrowing base under the Credit Facility is subject to re-determination on April 1 and October 1 of each year. The current borrowing base as determined by the lenders is $425.0 million. Each re-determination is based primarily on a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the lenders, and to a lesser extent, the loan value the lenders reasonably attribute to Superior Pipeline Company's cash flow as defined in the Credit Facility. The Credit Facility allows for one requested special re-determination of the borrowing base by either the banks or the company between each scheduled re-determination date and additional redeterminations may be requested by the borrowers following the consummation of any acquisition as defined in the Credit Facility. The lender's aggregate commitment is limited to the lesser of the amount of the borrowing base or $400 million.

At the company's election, any part of the outstanding debt may be fixed at a London Interbank Offered Rate (LIBOR) Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which the LIBOR Rate 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 Rate is computed at the LIBOR Base Rate 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 Rate 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 June 30, 2007, all of the $209.8 million of the company's borrowings was subject to the LIBOR rate.

The Credit Facility includes prohibitions against:

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

The Credit Facility also requires that the company 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 June 30, 2007, the company was in compliance with the covenants of the Credit Facility.

Other long-term liabilities consisted of the following:

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (In thousands) | |
| Separation Benefit Plans | $ 3,999 | $ 3,516 |
| Deferred Compensation Plan | 2,829 | 2,544 |
| Retirement Agreement | 1,059 | 1,386 |
| Workers' Compensation | 22,503 | 22,157 |
| Gas Balancing Liability | 1,080 | 1,080 |
| Plugging Liability | 34,419 | 33,692 |
| | 65,889 | 64,375 |
| Less Current Portion | 10,461 | 8,634 |
| Total Other Long-Term Liabilities | $ 55,428 | $ 55,741 |

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning July 1, 2007 through 2010 are \$10.5 million, \$4.1 million, \$1.9 million, \$2.3 million and \$2.4 million. Based on the borrowing rates currently available to the company for debt with similar terms and maturities, long-term debt at June 30, 2007 approximates its fair value.

**NOTE 5 – ASSET RETIREMENT OBLIGATIONS**

Under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) the company must record the fair value of liabilities associated with the retirement of long-lived assets. The company owns oil and natural gas properties which require cash to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted or the wells are no longer able to produce. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). The company does not have any assets restricted for the purpose of settling these plugging liabilities.

The following table shows the activity for the six months ending June 30, 2007 and 2006 relating to the company's retirement obligation for plugging liability:

| | Six Months Ended | |
|---|---|---|
| | 2007 | 2006 |
| | (In Thousands) | |
| Plugging Liability, January 1: | $ 33,692 | $ 22,015 |
| Accretion of Discount | 889 | 696 |
| Liability Incurred | 786 | 1,867 |
| Liability Settled | (1,113) | (101) |
| Revision of Estimates | 165 | 6,984 |
| Plugging Liability, June 30 | 34,419 | 31,461 |
| Less Current Portion | 1,629 | 607 |
| Total Long-Term Plugging Liability | $ 32,790 | $ 30,854 |

**NOTE 6 - NEW ACCOUNTING PRONOUNCEMENTS**

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS No. 109, "Accounting for Income Taxes" and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The company adopted the provisions of FIN 48 effective January 1, 2007. The company has no unrecognized tax benefits and the adoption of FIN 48 had no effect on the company's results of operations or financial condition and we do not expect any significant changes in unrecognized tax benefits in the next twelve months.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation".) which became effective for the company on January 1, 2007. According to the provisions of EITF 06-3:

- taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

- that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies." In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

Because the provisions of EITF 06-3 require only the presentation of additional disclosures, the adoption of EITF 06-3 did not have an effect on the company's statements of income, financial condition or cash flows. The company collects sales and use tax when it sells used equipment or rents drilling equipment to third parties. The sales and use tax is reported net. Gross production taxes associated with the sale of oil and natural gas production is reported on a gross basis and was $12.1 million for the first six months of 2007 and $11.0 million for the first six months of 2006.

In September 2006, the FASB issued FAS No. 157, "Fair Value Measurements" (FAS 157). FAS 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS 157 is effective for fiscal years beginning after November 15, 2007. The company is currently assessing the impact of FAS 157 on its statement of income, financial condition and cash flows.

In February 2007, the FASB issued FAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115", (FAS 159) which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. The company is currently assessing the impact of FAS 159 on its statement of income, financial condition and cash flows.

## NOTE 7 – GOODWILL

Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill of $5.5 million was added from the acquisition completed in the second quarter of 2007. An annual impairment test is performed in the fourth quarter of each year to determine whether the fair value has decreased and additionally when events indicate an impairment may have occurred. Goodwill is all related to the company's drilling segment.

## NOTE 8 – HEDGING ACTIVITY

The company periodically enters into derivative commodity instruments to hedge its exposure to the fluctuations in the prices it receives for its oil and natural gas production and mid-stream activities. These instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists.

In June 2007, the company entered into natural gas liquids sales swaps and natural gas purchase swaps to lock in a percentage of the company's Mid-Stream segment's frac spread for natural gas processed. The frac spread is the difference in the value received for liquids recovered from natural gas in comparison to the amount received for the equivalent MMBtu's of natural gas if unprocessed. These swaps pertain to approximately 65% of our Mid-Stream segments total liquid sales. The following table provides additional information pertaining to the swap contracts for the time periods covering July through November of 2007:

| Commodity | Quantity | Price | Underlying Commodity Price |
|---|---|---|---|
| Ethane | 623,868 gal./month | $ 0.6225 | OPIS Ethane Conway |
| Propane | 396,690 gal./month | $ 1.1475 | OPIS Propane Conway |
| Propane | 396,690 gal./month | $ 1.15 | OPIS Propane Conway |
| Iso Butane | 61,782 gal./month | $ 1.2625 | OPIS Iso Butane Conway |
| Iso Butane | 61,782 gal./month | $ 1.2975 | OPIS Iso Butane Conway |
| Normal Butane | 163,632 gal./month | $ 1.2975 | OPIS Normal Butane Conway |
| Normal Butane | 163,632 gal./month | $ 1.27 | OPIS Normal Butane Conway |
| Natural Gasoline | 411,012 gal./month | $ 1.7375 | OPIS Nat. Gas Conway In-Well |
| Natural Gas | 107,710 MMBtu/month | $ 7.00 | IF PEPL Natural Gas |
| Natural Gas | 107,710 MMBtu/month | $ 7.04 | IF PEPL Natural Gas |

All of these swaps are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the swap contracts was recognized on the June 30, 2007 balance sheet as a derivative liability of $1.7 million and a loss of $1.0 million, net of tax, in accumulated other comprehensive income.

In January and February 2007, the company entered into the following two natural gas collar contracts:

| **First Contract:** | |
|---|---|
| Production volume covered | 10,000 MMBtu/day |
| Period covered | May through December of 2007 |
| Prices | Floor of $6.00 and a ceiling of $10.00 |
| Underlying commodity price | Centerpoint Energy Gas Transmission Co., East – Inside FERC |

| **Second Contract:** | |
|---|---|
| Production volume covered | 10,000 MMBtu/day |
| Period covered | March through December of 2007 |
| Prices | Floor of $6.25 and a ceiling of $9.25 |
| Underlying commodity price | Centerpoint Energy Gas Transmission Co., East – Inside FERC |

In December 2006, the company also entered into the following natural gas hedging transaction:

| **Contract:** | |
|---|---|
| Production volume covered | 10,000 MMBtu/day |
| Period covered | January through December of 2007 |
| Prices | Floor of $6.00 and a ceiling of $9.60 |
| Underlying commodity price | Centerpoint Energy Gas Transmission Co., East – Inside FERC |

All of these hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the June 30, 2007 balance sheet as a derivative asset of $1.4 million and at a gain of $0.9 million, net of tax, in accumulated other comprehensive income.

In February 2005, the company entered into an interest rate swap to help manage its exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, in the second quarter and first six months of 2007 the company's interest expense was decreased by $0.2 million and $0.3 million, respectively. The company's interest expense was decreased by $0.1 million in the second quarter of 2006 and $0.2 million for the six months ended June 30, 2006. The fair value of the swap was recognized on the June 30, 2007 balance sheet as current and non-current derivative assets totaling $0.4 million and a gain of $0.3 million, net of tax, in accumulated other comprehensive income.

## NOTE 9 - INDUSTRY SEGMENT INFORMATION

The company has three business segments:

- Contract Drilling,
- Oil and Natural Gas and
- Mid-Stream

These three segments represent the company's three main business units offering different products and services. 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.

The company evaluates the performance of these operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. The company has natural gas production in Canada, which is not significant. Information regarding the company's operations by segment for the three and six month periods ended June 30, 2007 and 2006 is as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In thousands) | | | |
| Revenues: | | | | |
| Contract drilling | $ 164,987 | $ 185,793 | $ 333,800 | $ 353,475 |
| Elimination of inter-segment revenue | 10,638 | 9,885 | 19,166 | 16,137 |
| Contract drilling net of inter-segment revenue | 154,349 | 175,908 | 314,634 | 337,338 |
| Oil and natural gas | 96,343 | 81,954 | 182,449 | 176,280 |
| Gas gathering and processing | 38,935 | 25,020 | 72,866 | 54,258 |
| Elimination of inter-segment revenue | 3,166 | 3,300 | 6,329 | 7,056 |
| Gas gathering and processing net of inter-segment revenue | 35,769 | 21,720 | 66,537 | 47,202 |
| Other (1) | 179 | 767 | 291 | 2,337 |
| Total revenues | $ 286,640 | $ 280,349 | $ 563,911 | $ 563,157 |
| Operating Income (2): | | | | |
| Contract drilling | $ 65,938 | $ 83,946 | $ 137,219 | $ 153,226 |
| Oil and natural gas | 41,159 | 37,925 | 75,779 | 89,763 |
| Gas gathering and processing | 1,819 | 1,771 | 2,747 | 3,302 |
| Total operating income | 108,916 | 123,642 | 215,745 | 246,291 |
| General and administrative expense | (5,247) | (4,402) | (10,429) | (8,368) |
| Interest expense | (1,729) | (1,017) | (3,370) | (2,007) |
| Other income - net | 179 | 767 | 291 | 2,337 |
| Income before income taxes | $ 102,119 | $ 118,990 | $ 202,237 | $ 238,253 |

(1) Includes a $1.0 million gain from insurance proceeds on the loss of a drilling rig from a blow out and fire in January 2006.

(2) 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 consolidated condensed balance sheet of Unit Corporation and its subsidiaries as of June 30, 2007, and the related consolidated condensed statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2007 and 2006 and the consolidated condensed statements of cash flows for the six-month periods ended June 30, 2007 and 2006. 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 consolidated condensed 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, 2006, 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 March 1, 2007 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated condensed balance sheet as of December 31, 2006, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
August 2, 2007

**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:

- Financial Condition
- Results of Operations
- New Accounting Pronouncements

MD&A should be read in conjunction with the Consolidated Condensed Financial Statements and related notes included in this report as well as the information contained in our Annual Report on Form 10-K.

Unless otherwise indicated or required by the content, as 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.

**FINANCIAL CONDITION**

***Summary***. Our financial condition and liquidity depends on the cash flow from our three principal business segments (and our subsidiaries that carry out those operations) and borrowings under our bank credit facility.

Our cash flow is influenced mainly by:

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

Our three principal business segments are:

- contract drilling carried out by our subsidiaries Unit Drilling Company and it subsidiaries Unit Texas Drilling, L.L.C. and Leonard Hudson Drilling Company;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company; and its subsidiaries; and
- mid stream operations (consisting of natural gas buying, selling, gathering, processing and treating) carried outby our subsidiary Superior Pipeline Company, L.L.C.

The following is a summary of certain financial information as of June 30, 2007 and 2006 and for the six months ended June 30, 2007 and 2006:

| | June 30, 2007 | June 30, 2006 | Percent Change |
|---|---|---|---|
| | (In thousands except percent amounts) | | |
| Working Capital | $ 87,311 | $ 75,659 | 15% |
| Long-Term Debt | $ 209,800 | $ 129,700 | 62% |
| Shareholders' Equity | $ 1,293,040 | $ 992,101 | 30% |
| Ratio of Long-Term Debt to Total Capitalization | 14% | 12% | 17% |
| Net Income | $ 130,048 | $ 149,730 | (13)% |
| Net Cash From Operating Activities | $ 219,352 | $ 223,485 | (2)% |
| Net Cash Used in Investing Activities | $ (258,753) | $ (210,407) | 23% |
| Net Cash From (Used in) Financing Activities | $ 39,390 | $ (13,224) | 398% |

The following table summarizes certain operating information for the six months ended June 30, 2007 and 2006:

| | June 30, 2007 | June 30, 2006 | Percent Change |
|---|---|---|---|
| Oil Production (MBbls) | 789 | 685 | 15% |
| Natural Gas Production (MMcf) | 21,301 | 21,150 | 1% |
| Average Oil Price Received | $ 50.66 | $ 55.88 | (9)% |
| Average Oil Price Received Excluding Hedges | $ 50.66 | $ 55.88 | (9)% |
| Average Natural Gas Price Received | $ 6.58 | $ 6.41 | 3% |
| Average Natural Gas Price Received Excluding Hedges | $ 6.57 | $ 6.41 | 2% |
| Average Number of Our Drilling Rigs in Use During the Period | 97.4 | 109.5 | (11)% |
| Total Number of Drilling Rigs Available at the End of the Period | 128 | 115 | 11% |
| Average Dayrate | $ 19,062 | $ 17,870 | 7% |
| Gas Gathered—MMBtu/day | 222,164 | 229,448 | (3)% |
| Gas Processed—MMBtu/day | 42,984 | 30,835 | 39% |
| Gas Liquids Sold—Gallons/day | 104,946 | 50,749 | 107% |
| Number of Active Natural Gas Gathering Systems | 37 | 37 | ---% |
| Number of Active Processing Systems | 7 | 6 | 17% |

At June 30, 2007, we had unrestricted cash totaling $0.6 million and we had borrowed $209.8 million of the $275.0 million we have elected to have available under our Credit Facility.

***Our Bank Credit Facility.*** On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) which amended and restated the credit facility entered into between us and our lenders on January 30, 2004. The Credit Facility is a revolving credit facility maturing on May 24, 2012 and has a maximum credit amount of $400.0 million. Borrowings under the Credit Facility are limited to a commitment amount elected by us. On May 24, 2007, we elected to have an initial aggregate commitment amount of $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 six months of 2007 was 6.5%. At June 30, 2007 and July 31, 2007, our borrowings were $209.8 million and $197.8 million, respectively.

The borrowing base under the Credit Facility is subject to re-determination on April 1 and October 1 of each year. The current borrowing base as determined by the lenders is $425.0 million. Each re-determination is based primarily on a percentage of the discounted future value of our oil and natural gas reserves, as determined by the lenders, and to a lesser extent, the loan value the lenders reasonably attribute to Superior Pipeline Company's cash flow as defined in the Credit Facility. The Credit Facility allows for one requested special re-determination of the borrowing base by either the banks or us between each scheduled re-determination date and additional redeterminations may be requested by us following the consummation of any acquisition as defined in the Credit Facility. The lender's aggregate commitment is limited to the lesser of the amount of the borrowing base or $400 million.

At our election, any part of the outstanding debt may be fixed at a London Interbank Offered Rate (LIBOR) Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which such LIBOR Rate 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 Rate is computed at the LIBOR Base Rate 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 Rate 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 June 30, 2007, all of the $209.8 million we had borrowed was subject to the LIBOR rate.

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
- 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 June 30, 2007, we were in compliance with the Credit Facility's covenants.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was decreased by $0.3 million in the first six months of 2007. The fair value of the swap was recognized on the June 30, 2007 balance sheet as current and non-current derivative assets totaling $0.4 million and a gain of $0.3 million, net of tax, in accumulated other comprehensive income.

***Contractual Commitments***. At June 30, 2007 we had the following contractual obligations:

| Contractual Obligations | Total | Less Than 1 Year | 2-3 Years | 4-5 Years | After 5 Years |
|---|---|---|---|---|---|
| | **Payments Due by Period** | | | | |
| | | | **(In thousands)** | | |
| Bank Debt (1) | $ 270,328 | $ 12,376 | $ 24,684 | $ 233,268 | $ --- |
| Retirement Agreements (2) | 1,059 | 726 | 333 | --- | --- |
| Operating Leases (3) | 4,232 | 1,479 | 2,386 | 367 | --- |
| Drill Pipe, Drilling Rigs and Equipment Purchases (4) | 19,071 | 19,071 | --- | --- | --- |
| Total Contractual Obligations | $ 294,690 | $ 33,652 | $ 27,403 | $ 233,635 | $ --- |

(1) See the previous discussion in Management Discussion and Analysis regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated at the June 30, 2007 interest rate of 6.48% including the effect of the interest rate swap related to $50.0 million of the outstanding debt.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expense 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, will be paid in monthly payments of $25,000 starting in July 2003 and continuing through June 2009. In the first quarter of 2004, we acquired a liability for the present value of a separation agreement between PetroCorp Incorporated and one of its previous officers. The liability associated with this agreement will be paid in quarterly payments of $12,500 through December 31, 2007. 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, will be paid in monthly payments of $31,250 starting 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; 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) Due to the potential for limited availability of new drill pipe within the industry, we have committed to purchase approximately $16.6 million of drill pipe and drill collars. We have also committed to purchase $3.1 million of drilling rig components with 20% or $0.6 million paid through June 30, 2007.

At June 30, 2007, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

| Other Commitments | Total Amount Committed Or Accrued | Amount of Commitment Expiration Per Period: Less Than 1 Year | 2-3 Years | 4-5 Years | After 5 Years |
|---|---|---|---|---|---|
| | | (In thousands) | | | |
| Deferred Compensation Agreement (1) | $ 2,829 | Unknown | Unknown | Unknown | Unknown |
| Separation Benefit Agreement (2) | $ 3,999 | Unknown | Unknown | Unknown | Unknown |
| Plugging Liability (3) | $ 34,419 | $ 1,629 | $ 1,558 | $ 3,188 | $ 28,044 |
| Gas Balancing Liability (4) | $ 1,080 | Unknown | Unknown | Unknown | Unknown |
| Repurchase Obligations (5) | Unknown | Unknown | Unknown | Unknown | Unknown |
| Workers' Compensation Liability (6) | $ 22,503 | $ 8,106 | $ 4,067 | $ 1,469 | $ 8,861 |

(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 condensed 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 4 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 June 30, 2007, there were 33 eligible employees to participate in the plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143), 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 certain properties where we believe there are insufficient oil and natural gas reserves available 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 2007, with a subsidiary of ours serving as general partner. The Partnerships were formed for the purpose of conducting oil and natural gas

acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $7,000, $4,000 and $14,000 in 2006, 2005 and 2004, respectively and have not had any repurchases in 2007.

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

***Hedging.*** Periodically we hedge the prices we will receive for a portion of our future natural gas and oil production and mid-stream activities. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow.

In June 2007, we entered into the following natural gas liquids sales swaps and natural gas purchase swaps to lock in a percentage of our Mid-Stream segment's frac spread for natural gas processed. The frac spread is the difference in the value received for liquids recovered from natural gas in comparison to the amount received for the equivalent MMBtu's of natural gas if unprocessed. These swaps pertain to approximately 65% of our Mid-Stream segments total liquid sales. The following table provides additional information pertaining to the swap contracts for the time periods covering July through November of 2007:

| Commodity | Quantity | Price | Underlying Commodity Price |
|---|---|---|---|
| Ethane | 623,868 gal./month | $ 0.6225 | OPIS Ethane Conway |
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| Natural Gas | 107,710 MMBtu/month | $ 7.00 | IF PEPL Natural Gas |
| Natural Gas | 107,710 MMBtu/month | $ 7.04 | IF PEPL Natural Gas |

All of these swaps are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the swap contracts was recognized on the June 30, 2007 balance sheet as a derivative liability of $1.7 million and a loss of $1.0 million, net of tax, in accumulated other comprehensive income.

In January and February 2007, we entered into the following two natural gas collar contracts:

**First Contract:**

| | |
|---|---|
| Production volume covered | 10,000 MMBtu/day |
| Period covered | May through December of 2007 |
| Prices | Floor of $6.00 and a ceiling of $10.00 |
| Underlying commodity price | Centerpoint Energy Gas Transmission Co., East – Inside FERC |

**Second Contract:**

| | |
|---|---|
| Production volume covered | 10,000 MMBtu/day |
| Period covered | March through December of 2007 |
| Prices | Floor of $6.25 and a ceiling of $9.25 |
| Underlying commodity price | Centerpoint Energy Gas Transmission Co., East – Inside FERC |

In December 2006, we entered into the following natural gas collar contract:

**Contract:**

| | |
|---|---|
| Production volume covered | 10,000 MMBtu/day |
| Period covered | January through December of 2007 |
| Prices | Floor of $6.00 and a ceiling of $9.60 |
| Underlying commodity price | Centerpoint Energy Gas Transmission Co., East – Inside FERC |

All of these hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the June 30, 2007 balance sheet as a derivative asset of $1.4 million and at a gain of $0.9 million, net of tax, in accumulated other comprehensive income.

We did not have any oil, natural gas or natural gas liquids hedges outstanding at June 30, 2006.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was decreased by $0.2 million in the second quarter of 2007 and $0.3 million for the six months ended June 30, 2007. In the second quarter and first six months of 2006, our interest expense was decreased by $0.1 million and $0.2 million, respectively, as a result of the interest rate swap. The fair value of the swap was recognized on the June 30, 2007 balance sheet as current and non-current derivative assets totaling $0.4 million and a gain of $0.3 million, net of tax, in accumulated other comprehensive income.

***Self-Insurance or Retentions***. 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 $0.5 million for Oklahoma workers' compensation 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. With respect to our drilling operations conducted by Unit Texas Drilling LLC in Texas, we have elected to use an ERISA governed occupational injury benefit plan to cover that company's field and support staff in lieu of covering them under an insured Texas workers' compensation plan.

***Impact of Prices for Our Oil and Natural Gas***. Natural gas comprises 85% of our total oil and natural gas reserves. Any significant change in natural gas prices has a material effect on our revenues, cash flow and the value of our oil 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 six months 2007 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $334,000 per month ($4.0 million annualized) change in our pre-tax operating cash flow. Our first six month 2007 average natural gas price was $6.57 compared to an average natural gas price of $6.41 for the first six months of 2006. A $1.00 per barrel change in our oil price would have a $124,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow based on our production in the first six months of 2007. Our first six month 2007 average oil price was $50.66 compared with an average oil price of $55.88 received in the first six months of 2006.

Because oil and natural gas prices have such a significant affect on the value of our oil 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 effect 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 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.

***Oil and Natural Gas Acquisitions and Capital Expenditures.*** Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We drilled 121 wells (42.31 net wells) in the first six months of 2007 compared to 103 wells (38.65 net wells) in the first six months of 2006. Our total capital expenditures for oil and natural gas exploration in the first six months of 2007 totaled $135.1 million. We currently anticipate we will drill approximately 270 gross wells in 2007. We have estimated our total 2007 capital expenditures for oil and natural gas exploration to be approximately $326.0 million Whether we are able to drill the number of wells we anticipate drilling in 2007 is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, the weather and the efforts of our outside industry partners.

On May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition were included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. Included in this acquisition were all of Brighton's oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and results of operations from this acquisition are included in the statement of income beginning October 1, 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

***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 rigs and our ability to supply the equipment needed.

Although rig utilization declined in the fourth quarter of 2006 and continued to slowly decline in the first six months of 2007, we do not anticipate declines in labor cost per hour due to the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future technological requirements of the drilling industry. To help keep qualified labor, we previously implemented longevity pay incentives and as recently as the second quarter of 2006 provided pay increases in some of our operating districts. To date, these efforts have allowed us to meet our labor requirements. However, if current demand for drilling rigs strengthens above the first six month levels of 82%, shortages of experienced personnel may limit our ability to operate our drilling rigs.

We currently do not have any shortages of drill pipe and drilling equipment. Because of the potential for shortages in the availability of new drill pipe, at June 30, 2007 we have commitments to purchase approximately $16.6 million of drill pipe and drill collars in 2007 and we have also committed to purchase $3.1 million of additional rig components with 20% or a $0.6 million paid through June 30, 2007. We are refurbishing a drilling rig acquired in the second quarter 2007 drilling acquisition which should be placed in service in the third quarter of 2007 and one additional rig is scheduled to be placed in service in the fourth quarter of 2007.

Most of our contract drilling fleet is targeted to the drilling of 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 can charge for our contract drilling services. In June 2007, our average dayrate for the 128 drilling rigs that we owned was $18,637 with an 80% utilization rate. In the first six months of 2007 our average dayrate was $19,062 per day compared to $17,870 in the first six months of 2006. The average number of drilling rigs used was 97.4 (82%) in the first six months of 2007 compared to 109.5 (98%) in the first six months of 2006. Based on the average utilization of our drilling rigs during the first six months of 2007, a $100 per day change in dayrates has a $9,740 per day ($3.6

million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first six months of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with high levels of natural gas storage throughout the majority of the winter season. 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 are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties for comparable type projects. During the first six months of 2007 and 2006, we drilled 32 and 29 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $9.9 million and $8.6 million during the first six months of 2007 and 2006, respectively, reduced the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

***Drilling Acquisitions and Capital Expenditures.*** In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This drilling rig has been modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May 2006, we began moving a 1,500 horsepower drilling rig to our Rocky Mountain Division following completion of its construction in the first quarter of 2006 for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two new 1,500 horsepower drilling rigs for a total of $15.2 million of which $4.6 million was paid before the second quarter of 2006 and the balance of $10.6 million was paid at delivery of the rigs. An additional $3.0 million of modifications were made to the rigs before the rigs were placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower rig for approximately $9.5 million which was moved into our Rocky Mountain Division. In the last half of 2006 we completed construction of a 750 horsepower rig for approximately $4.5 million.

During 2006 we paid $4.5 million for the purchase of major components to construct two 1,500 horsepower drilling rigs. The first rig was being moved to the Rocky Mountain division at the end of March 2007 and was constructed for approximately $9.6 million. The second rig was placed in service in the second quarter of 2007 and was constructed for approximately $7.6 million. On June 5, 2007, we completed the acquisition of a privately owned drilling company operating primarily in the Texas Panhandle. The acquired drilling company owns 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. Seven of the nine drilling rigs were operating under contract at the acquisition date. Results of operations for the acquired company are included in the company’s statement of income beginning June 5, 2007. Total consideration paid for this acquisition was $38.5 million.

For our contract drilling operations, during the first six months of 2007, we recorded $147.2 million in capital expenditures including the effect of an $18.4 million deferred tax liability and $5.5 million in goodwill associated with our second quarter 2007 acquisition. For the year 2007, we have budgeted capital expenditures of approximately $131.0 million excluding acquisitions.

***Mid-Stream Operations***. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiary. Superior is a mid-stream company engaged primarily in the buying and selling, gathering, processing and treating of natural gas and operates four natural gas treatment plants, seven operating processing plants, 37 active gathering systems and 641 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas and has been in business since 1996. 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 six months of 2007, Superior purchased $3.9 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $2.4 million. 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. In the first six months of 2006, we eliminated intercompany revenues of $4.5 million of natural gas and $2.6 million of natural gas liquids.

***Mid-Stream Acquisitions and Capital Expenditures.*** In September 2006, we closed the acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in the company's statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

During the first six months of 2007, Superior incurred $18.0 million in capital expenditures compared to $10.0 million for the same period in 2006. For 2007, we have budgeted capital expenditures of approximately $25.0 million for Superior. Our focus is on growing this segment through the construction of new facilities or acquisitions.

***Oil and Natural Gas Limited Partnerships and Other Entity Relationships.*** We are the general partner for 12 oil and natural gas limited partnerships. Each partnership's revenues and costs are shared under formulas prescribed in its limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by management to be reasonable. During 2006, the total paid to us for all of these fees was $1.3 million and we expect the amount to approximately be the same in 2007. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated condensed financial statements.

## NEW ACCOUNTING PRONOUNCEMENTS

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS No. 109, "Accounting for Income Taxes" and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted the provisions of FIN 48 effective January 1, 2007. We have no unrecognized tax benefits and the adoption of FIN 48 had no effect on our results of operations of financial condition and we do not expect any significant changes in unrecognized tax benefits in the next twelve months.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation".) which became effective for us on January 1, 2007. According to the provisions of EITF 06-3:

- taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

- that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies." In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

Because the provisions of EITF 06-3 require only the presentation of additional disclosures, the adoption of EITF 06-3 did not have an effect on our statements of income, financial condition or cash flows. We collect sales and use tax when we sell used equipment or rent drilling equipment to third parties. The sales and use tax is reported net. Gross production taxes associated with the sale of oil and natural gas production is reported gross and was $12.1 million for the first six months of 2007 and $11.0 million for the first six months of 2006.

In September 2006, the FASB issued FAS No. 157, "Fair Value Measurements" (FAS 157). FAS 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of FAS 157 on our statement of income, financial condition and cash flows.

In February 2007, the FASB issued FAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115", (FAS 159) which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. We are currently assessing the impact of FAS 159 on our statement of income, financial condition and cash flows.

**RESULTS OF OPERATIONS**

**Quarter Ended June 30, 2007 versus Quarter Ended June 30, 2006**

Provided below is a comparison of selected operating and financial data for the second quarter of 2007 versus the second quarter of 2006:

| | Quarter Ended June 30, 2007 | Quarter Ended June 30, 2006 | Percent Change |
|---|---|---|---|
| Total Revenue | $ 286,640,000 | $ 280,349,000 | 2% |
| Net Income | $ 65,566,000 | $ 74,817,000 | (12)% |
| **Drilling:** | | | |
| Revenue | $ 154,349,000 | $ 175,908,000 | (12)% |
| Operating costs excluding depreciation | $ 74,729,000 | $ 79,117,000 | (6)% |
| Percentage of revenue from daywork contracts | 100% | 100% | --- |
| Average number of rigs in use | 97.9 | 110.3 | (11)% |
| Average dayrate on daywork contracts | $ 18,710 | $ 18,588 | 1% |
| Depreciation | $ 13,682,000 | $ 12,845,000 | 7% |
| **Oil and Natural Gas:** | | | |
| Revenue | $ 96,343,000 | $ 81,954,000 | 18% |
| Operating costs excluding depreciation, depletion and amortization | $ 24,461,000 | $ 18,988,000 | 29% |
| Average natural gas price (Mcf) | $ 6.78 | $ 5.76 | 18% |
| Average oil price (Bbl) | $ 53.18 | $ 57.11 | (7)% |
| Natural gas production (Mcf) | 10,628,000 | 10,438,000 | 2% |
| Oil production (Bbl) | 433,000 | 359,000 | 21% |
| Depreciation, depletion and amortization rate (Mcfe) | $ 2.31 | $ 1.98 | 17% |
| Depreciation, depletion and amortization | $ 30,723,000 | $ 25,041,000 | 23% |
| **Gas Gathering and Processing:** | | | |
| Revenue | $ 35,769,000 | $ 21,720,000 | 65% |
| Operating costs excluding depreciation and amortization | $ 31,395,000 | $ 18,717,000 | 68% |
| Depreciation and amortization | $ 2,555,000 | $ 1,232,000 | 107% |
| Gas gathered – MMbtu/day | 218,290 | 243,399 | (10)% |
| Gas processed – MMbtu/day | 42,645 | 31,000 | 38% |
| Gas liquids sold – Gallons/day | 113,829 | 50,169 | 127% |
| | | | |
| General and Administrative Expense | $ 5,247,000 | $ 4,402,000 | 19% |
| Interest Expense | $ 1,729,000 | $ 1,017,000 | 70% |
| Income Tax Expense | $ 36,553,000 | $ 44,173,000 | (17)% |
| Average Interest Rate | 6.11% | 5.78% | 6% |
| Average Long-Term Debt Outstanding | $ 179,192,000 | $ 118,220,000 | 52% |

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first six months of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with the high levels of natural gas storage throughout the majority of the winter season and again this summer. Drilling revenues decreased $21.6 million or 12% in the second quarter of 2007 versus the second quarter of 2006. Since the first quarter of 2006, we have placed 16 additional drilling rigs into service. We have constructed seven drilling rigs and in June 2007 we acquired nine drilling rigs. Thirteen of these additional drilling rigs provided contract drilling services in the second quarter of 2007 increasing drilling revenues by $9.8 million or 6% of revenues in the second quarter of 2006. Revenues for rigs previously owned declined $31.4 million or 18% of the revenues in the second quarter of 2006 and more than offset the increase in revenue from rigs added subsequent to the second quarter of 2006. Average rig utilization declined from 110.3 rigs in the second quarter of 2006 to 97.9 in the second quarter of 2007. The decline in rig utilization decreased drilling revenues by $19.7 million while decreases in revenue per day between the comparative second quarters decreased revenue by $1.9 million. Our average dayrate in the second quarter of 2007 was 1% higher than in the second quarter of 2006. Demand for our drilling rigs is anticipated to remain in the 80% to 85% range in the short term. With decreases in drilling rig demand, we experienced a 4% decline in the second quarter 2007 average dayrate compared to the first quarter 2007 average dayrate and we expect further decreases in average dayrates to continue into the third quarter.

Drilling operating costs decreased $4.4 million or 6% between the comparative quarters. Operating cost decreased as utilization dropped 12.4 rigs between the comparative quarters. Operating cost per day increased $501 in the second quarter of 2007 when compared with the second quarter of 2006 and partially offset the decrease from reduced operating days. The majority of the increase in cost per day was attributable to indirect drilling cost for repair supplies and maintenance and property taxes and to a lesser extent costs directly associated with drilling wells. With continued competition for qualified labor and utilization continuing at 80% or above, we expect our drilling rig expenses per day to remain steady or increase slightly over the remainder of 2007. Contract drilling depreciation increased $0.8 million or 7%. The addition of the net 16 drilling rigs placed in service since the first quarter of 2006 and additional assets acquired in the 2007 second quarter rig acquisition increased depreciation $0.8 million with the increase partially offset from the effect of decreased utilization.

Oil and natural gas revenues increased $14.4 million or 18% in the second quarter of 2007 as compared to the second quarter of 2006 due to an increase in equivalent production volumes of 5% and an increase in average natural gas prices. The increases were partially offset by decreased oil prices. Average natural gas prices between the comparative quarters increased 18% to $6.78 per Mcf while oil prices declined 7% to $53.18 per barrel. In the second quarter of 2007, natural gas production increased by 2% while oil production increased 21%. Increased natural gas and oil production came primarily from our ongoing development drilling activity and from acquisitions completed in 2006. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2007 compared to 2006 will increase 6% to 10%. 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 29% in the second quarter of 2007 as compared to 2006. An increase in the average cost per equivalent Mcf produced represented 81% of the increase in production costs with the remaining 19% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 69% of the increase, gross production taxes 20%, general and administrative cost directly related to oil and natural gas production 10% and increased accretion on plugging liability 1%. Lease operating expenses per Mcfe increased 26% between the comparative quarters as post production transportation cost, salt water disposal fees and compression increased along with a 79% increase in workover cost. Gross production taxes increased due to the increase in oil and natural gas volumes produced between the comparative quarters and the increase in natural gas prices. 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. Total depreciation, depletion and amortization (“DD&A”) increased $5.7 million or 23%. Higher production volumes accounted for 22% of the increase while increases in our DD&A rate represented 78% of the increase. The increase in our DD&A rate in the second quarter of 2007 compared to the second quarter of 2006 resulted primarily from an 18% increase in our finding cost in 2006 and continued increases in our finding cost into the first six months of 2007. Increasing demand for drilling rigs prior to the fourth quarter of 2006 throughout our areas of exploration increased the dayrates we pay to drill wells in our developmental program. Increases in natural gas and oil prices over the last two years have also caused increased sales prices for producing property acquisitions and even with the increased sales prices, we continue to see strong competition for producing property acquisitions.

Our mid-stream segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate four natural gas treatment plants and own seven operating processing plants, 37 active gathering systems and 641 miles of pipeline. These operations are conducted in Oklahoma, Texas, Louisiana and Kansas. Intercompany revenue from services and purchases of production between our natural gas gathering and processing segment and our oil and natural gas segments has been eliminated. Our mid-stream revenues were $14.0 million or 65% higher in the second quarter of 2007 as compared to the second quarter of 2006 due to the higher volumes of natural gas sales and processing combined with higher natural gas and liquids prices. The average price for gas sold was 18% higher and the average price for liquids sold was 9% higher. Gas processing volumes per day increased 38% between the comparative quarters and gas liquids sold per day increased 127% between the comparative quarters. A 10% decrease in gathering volumes per day and a 13% decrease in the average price received for gas transportation volumes combined to partially offset the increase in revenue from natural gas sales and processing. The significant increase in volumes processed per day is primarily attributable to the acquisition of a processing plant in September of 2006 and to a lesser extent volumes from wells added to existing systems throughout 2006. Gas liquids sold volumes per day increased due to recent upgrades to several of our processing facilities. Operating costs increased 68% in the second quarter of 2007 compared with the second quarter of 2006 due to a 19% increase in prices paid for natural gas purchased, a 35% increase in natural gas volumes purchased, a 69% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas processed and a 49% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 38%. The 107% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Gas gathering volumes per day in the second quarter of 2007 were down 3% compared to the first quarter of 2007 primarily due to a slow down of new well connections associated with adverse winter weather and pipeline construction delays. Subsequent declines will continue until further field development results in new well connections. Gas processing volumes per day in the second quarter of 2007 were relatively unchanged compared to the first quarter of 2007.

General and administrative expense increased $0.8 million in the second quarter of 2007 compared to the second quarter of 2006. The increase in cost was primarily from a 17% increase in the number of employees associated with the growth of the company and the increases in employee compensation cost.

Total interest expense increased 70% between the comparative quarters. Average debt outstanding was 52% higher in the second quarter of 2007 as compared to the second quarter of 2006 primarily due to the acquisition of producing properties in the last four months of 2006 and the acquisition of a drilling company in the second quarter of 2007. Average debt outstanding accounted for approximately 84% of the interest expense increase, with the remaining 16% resulting from an increase in average interest rates on our bank debt. Interest expense was reduced $0.2 million from the settlements of our interest rate swap. Associated with our increased level of development 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 second quarter of 2007 compared with $0.9 million in the second quarter of 2006.

Income tax expense decreased $7.6 million or 17% due primarily to the decrease in income before income taxes. Our effective tax rate for the second quarter of 2007 was 35.8% versus 37.1% in the second quarter of 2006 due primarily to the increase in manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense for the second quarter of 2007 was $19.7 million or 54% of total income tax expense as compared with $33.1 million or 75% of total income tax expense in the second quarter of 2006. Income taxes paid in the second quarter of 2007 were $28.0 million.

**Six Months Ended June 30, 2007 versus Six Months Ended June 30, 2006**

Provided below is a comparison of selected operating and financial data for the first six months of 2007 versus the first six months of 2006:

| | Six Months Ended June 30, 2007 | Six Months Ended June 30, 2006 | Percent Change |
|---|---|---|---|
| Total Revenue | $ 563,911,000 | $ 563,157,000 | ---% |
| Net Income | $ 130,048,000 | $ 149,730,000 | (13)% |
| **Drilling:** | | | |
| Revenue | $ 314,634,000 | $ 337,338,000 | (7)% |
| Operating costs excluding depreciation | $ 151,016,000 | $ 159,426,000 | (5)% |
| Percentage of revenue from daywork contracts | 100% | 100% | --- |
| Average number of rigs in use | 97.4 | 109.5 | (11)% |
| Average dayrate on daywork contracts | $ 19,062 | $ 17,870 | 7% |
| Depreciation | $ 26,399,000 | $ 24,686,000 | 7% |
| **Oil and Natural Gas:** | | | |
| Revenue | $ 182,449,000 | $ 176,280,000 | 3% |
| Operating costs excluding depreciation, depletion and amortization | $ 46,600,000 | $ 37,294,000 | 25% |
| Average natural gas price (Mcf) | $ 6.58 | $ 6.41 | 3% |
| Average oil price (Bbl) | $ 50.66 | $ 55.88 | (9)% |
| Natural gas production (Mcf) | 21,301,000 | 21,150,000 | 1% |
| Oil production (Bbl) | 789,000 | 685,000 | 15% |
| Depreciation, depletion and amortization rate (Mcfe) | $ 2.29 | $ 1.94 | 18% |
| Depreciation, depletion and amortization | $ 60,070,000 | $ 49,223,000 | 22% |
| **Gas Gathering and Processing:** | | | |
| Revenue | $ 66,537,000 | $ 47,202,000 | 41% |
| Operating costs excluding depreciation, and amortization | $ 58,896,000 | $ 41,518,000 | 42% |
| Depreciation and amortization | $ 4,894,000 | $ 2,382,000 | 105% |
| Gas gathered – MMbtu/day | 222,164 | 229,448 | (3)% |
| Gas processed – MMbtu/day | 42,984 | 30,835 | 39% |
| Gas liquids sold – Gallons/day | 104,946 | 50,749 | 107% |
| General and Administrative Expense | $ 10,429,000 | $ 8,368,000 | 25% |
| Interest Expense | $ 3,370,000 | $ 2,007,000 | 68% |
| Income Tax Expense | $ 72,189,000 | $ 88,523,000 | (18)% |
| Average Interest Rate | 6.14% | 5.60% | 10% |
| Average Long-Term Debt Outstanding | $ 171,862,000 | $ 115,922,000 | 48% |

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first six months of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with the high levels of natural gas storage throughout the majority of the winter season and again this summer.

Drilling revenues decreased $22.7 million or 7% in the first six months of 2007 versus the first six months of 2006. Since the first quarter of 2006, we have placed 16 additional drilling rigs into service. We have constructed seven drilling rigs and in June 2007 we acquired nine drilling rigs. Thirteen of these additional drilling rigs provided contract drilling services in the first six months of 2007 increasing drilling revenues by $16.7 million or 5% of revenues in the first six months of 2006. Revenues for rigs previously owned declined $39.4 million or 12% from revenues in the first six months of 2006 and more than offset the increase in revenue from rigs added subsequent to the first quarter of 2006. Average rig utilization declined from 109.5 rigs in the first six months of 2006 to 97.4 in the first six months of 2007. The decline in rig utilization decreased drilling revenues by $37.3 million while increases in dayrates between the comparative six months periods provided additional revenue of $14.6 million partially offsetting utilization decreases. Our average dayrate in the first six months of 2007 was 7% higher than in the first six months of 2006. Demand for our drilling rigs is anticipated to remain in the 80% to 85% range in the short term. With decreases in drilling rig demand, we experienced a 4% decline in the second quarter 2007 average dayrate compared to the first quarter 2007 average dayrate and we expect further decreases in average dayrates to continue into the third quarter.

Drilling operating costs decreased $8.4 million or 5% between the comparative six month periods. Operating cost decreased as utilization dropped 12.1 rigs between the comparative six month periods. Operating cost per day increased $523 in the first six months of 2007 when compared with the first six months of 2006 and partially offset the decrease from less operating days. The majority of the increase in cost per day was attributable to indirect drilling cost for repair supplies and maintenance and property taxes and costs directly associated with drilling wells. With continued competition for qualified labor and utilization continuing at 80% or above, we expect our drilling rig expenses per day to remain steady or increase slightly over the remainder of 2007. Contract drilling depreciation increased $1.7 million or 7%. The addition of the 16 drilling rigs placed in service since the first quarter of 2006 and additional assets acquired in the 2007 second quarter rig acquisition increased depreciation with the increase partially offset from the effect of decreased utilization.

Oil and natural gas revenues increased $6.2 million or 3% in the first six months of 2007 as compared to the first six months of 2006 due to an increase in equivalent production volumes of 3% and an increase in average natural gas prices. The increases were partially offset by decreased oil prices. Average natural gas prices between the comparative six month periods increased 3% to $6.58 per Mcf while oil prices declined 9% to $50.66 per barrel. In the first six months of 2007, natural gas production increased by 1% while oil production increased 15%. Increased natural gas and oil production came primarily from our ongoing development drilling activity and from acquisitions completed in 2006. Production increases primarily in the first quarter of 2007 were limited due to the impact from a Texas refinery fire, adverse winter weather, pipeline construction delays preventing the connection of wells recently drilled and the timing of completion of certain wells. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2007 compared to 2006 will increase 6% to 10%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $9.3 million or 25% in the first six months of 2007 as compared to the first six months of 2006. An increase in the average cost per equivalent Mcf produced represented 87% of the increase in production costs with the remaining 13% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 74% of the increase, gross production taxes 11%, general and administrative cost directly related to oil and natural gas production 13% and increased accretion on plugging liability 2%. Lease operating expenses per Mcfe increased 26% between the comparative six month periods as post production transportation cost, salt water disposal fees and compression increased along with a 63% increase in workover cost. Gross production taxes increased due to the increase in oil and natural gas volumes produced between the comparative quarters and the increase in natural gas prices. General and administrative expenses increased as labor costs increased primarily due to a 13% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization (“DD&A”) increased $10.8 million or 22%. Higher production volumes accounted for 14% of the increase while increases in our DD&A rate represented 86% of the increase. The increase in our DD&A rate in the first six months of 2007 compared to the first six months of 2006 resulted primarily from an 18% increase in our finding cost in 2006 and continued increases in our finding cost into the first six months of 2007. Increasing demand for drilling rigs prior to the fourth quarter of 2006 throughout our areas of exploration increased the dayrates we pay to drill wells in our developmental program. Increases in natural gas and oil prices over the last two years have also caused increased sales prices for producing property acquisitions and even with the increased sales prices, we continue to see strong competition for producing property acquisitions.

Our mid-stream segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate four natural gas treatment plants and own seven operating processing plants, 36 active gathering systems and 641 miles of pipeline. These operations are conducted in Oklahoma, Texas, Louisiana and Kansas. Intercompany revenue from services and purchases of production between our natural gas gathering and processing segment and our oil and natural gas segments has been eliminated. Our mid-stream revenues were $19.3 million or 41% higher in the first six months of 2007 as compared to the first six months of 2006 due to the higher volumes of natural gas sales and processing combined with higher natural gas prices. The average price for gas sold was 1% higher and the average price for liquids sold was unchanged. Gas processing volumes per day increased 39% between the comparative six month periods and gas liquids sold per day increased 107% between the comparative six month periods. A 3% decrease in gathering volumes per day as gas transportation prices remained unchanged partially offset the increase in revenue from natural gas sales and processing. The significant increase in volumes processed per day is primarily attributable to the acquisition of a processing plant in September of 2006 and to a lesser extent volumes from wells added to existing systems throughout 2006. Gas liquids sold volumes per day increased due to recent upgrades to several of our processing facilities. Operating costs increased 42% in the first six months of 2007 compared with the first six months of 2006 due an 19% increase in prices paid for natural gas purchased, to a 19% increase in natural gas volumes purchased, an 84% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas processed and a 40% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 13%. The 105% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Gas gathering volumes per day in the second quarter of 2007 were down 3% compared to the first quarter of 2007 primarily due to a slow down of new well connections associated with adverse winter weather and pipeline construction delays. Subsequent declines will continue until further field development results in new well connections. Gas processing volumes per day in the second quarter of 2007 were relatively unchanged compared to the first quarter of 2007.

General and administrative expense increased $2.1 million in the first six months of 2007 compared to the first six months of 2006. The increase in cost was primarily from a 17% increase in the number of employees associated with the growth of the company and increases in employee compensation cost.

Total interest expense increased 68% between the comparative six month periods. Average debt outstanding was 48% higher in the first six months of 2007 as compared to the six months of 2006 primarily due to the acquisition of producing properties in the last four months of 2006 and the acquisition of a drilling company in the second quarter of 2007. Average debt outstanding accounted for approximately 78% of the interest expense increase, with the remaining 22% resulting from an increase in average interest rates on our bank debt. Interest expense was reduced $0.3 million from settlements of our interest rate swap. Associated with our increased level of development of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $2.2 million of interest in the first six months of 2007 compared with $1.6 million in the first six months of 2006.

Income tax expense decreased $16.3 million or 18% due primarily to the decrease in income before income taxes. Our effective tax rate for the first six months of 2007 was 35.7% versus 37.2% in the first six months of 2006 due primarily to the increase in manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense for the first six months of 2007 was $42.3 million or 59% of total income tax expense in the first six months of 2007 as compared with $63.3 million or 72% of total income tax expense in the first six months of 2006. Income taxes paid in the first six months of 2007 were $36.0 million.

In January 2006, one of our drilling rigs was destroyed by a fire. No personnel were injured although the drilling rig was a total loss. Insurance proceeds for the loss exceeded our net book value and provided a gain of approximately $1.0 million which is recorded in other revenues.

## SAFE HARBOR STATEMENT

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

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

- the amount and nature of our future capital expenditures;
- 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 six months of 2007 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $334,000 per month ($4.0 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $124,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow.

In an effort to try and reduce the impact of price fluctuations, over the past several years we have periodically used hedging strategies to hedge the price we will receive for a portion of our future oil and natural gas production. A detailed explanation of those transactions has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above.

In an effort to try and reduce the impact of price fluctuations received for natural gas liquids, in June 2007 we entered into a series of natural gas liquid sales and natural gas purchase swaps to effectively lock in the frac spread we receive on approximately 65% of our liquids processed and sold. A detailed explanation of those transactions has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above.

***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. In February 2005, we entered into an interest rate swap for $50.0 million of our outstanding debt to help manage our exposure to any future interest rate volatility. A detailed explanation of this transaction has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above. Based on our average outstanding long-term debt subject to the floating rate in the first six months of 2007, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $1.2 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 the company's disclosure controls and procedures are effective as of June 30, 2007 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 the company's internal controls over financial reporting during the quarter ended June 30, 2007 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, 2006, 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, 2006.

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

Not applicable

### Item 3. Defaults Upon Senior Securities

Not applicable

### Item 4. Submission of Matters to a Vote of Security Holders

On May 2, 2007 we held our Annual Meeting of Stockholders. At the meeting the following matters were voted on, with each receiving the votes indicated:

I. Election of Director Nominees William B. Morgan, John H. Williams and LarryD. Pinkston for a three-year term expiring in 2010.

| Nominee | Numbers of Votes For | Against or Withheld |
|---|---|---|
| William B. Morgan | 40,984,461 | 1,034,430 |
| John H. Williams | 41,010,193 | 1,008,698 |
| Larry D. Pinkston | 41,025,845 | 993,046 |

The following directors, whose term of office did not expire at the annual meeting, continue as directors of the Company: King P. Kirchner, Don Cook, J. Michael Adcock, John G. Nikkel, Robert J. Sullivan, Jr., and Gary R. Christopher.

II. Ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year 2007.

| | |
|---|---|
| For - | 41,910,421 |
| Against - | 56,528 |
| Abstain - | 51,947 |

**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: August 2, 2007

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

Date: August 2, 2007

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

EX-15 2 exhibit15v2.htm EXHIBIT 15 AWARENESS LETTER

**Exhibit 15**

August 2, 2007

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

Commissioners:

We are aware that our report dated August 2, 2007 on our review of interim financial information of Unit Corporation for the three and six month periods ended June 30, 2007 and 2006 and included in the Company's quarterly report on Form 10-Q for the quarter ended June 30, 2007 is incorporated by reference in its registration statements on Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166, 333-39584, 333-135194 and 333-137857) and Form S-3 (File No.'s 333-104165, 333-83551, 333-99979 and 333-128213).

Very truly yours,

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

EX-31.1 3 exhibit311.htm EXHIBIT 31.1 CERTIFICATION OF CEO

**Exhibit 31.1**

**302 CERTIFICATIONS**

I, Larry D. Pinkston, certify that:

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

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

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

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

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

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

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

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

and

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

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

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

Date: August 2, 2007

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

EX-31.2 4 exhibit312.htm EXHIBIT 31.2 CERTIFICATION OF CFO

**Exhibit 31.2**

**SECTION 302 CERTIFICATIONS**

I, David T. Merrill, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 2, 2007

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

EX-32 5 exhibit32.htm EXHIBIT 32 SECTION 906 CERTIFICATION

**Exhibit 32**

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

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

The Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of June 30, 2007 and December 31, 2006 and for the three and six month periods ended June 30, 2007 and 2006.

Dated: August 2, 2007

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

Dated: August 2, 2007

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

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

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