SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2005

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 ☒ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ☒ No ☐

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

Yes ☐ No ☒

Common Stock, $.20 par value	**45,859,404**

Class	Outstanding at August 2, 2005

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

	June 30, 2005 (Unaudited)	December 31, 2004
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,616	$ 665
Restricted cash	17	2,571
Accounts receivable	106,065	93,180
Materials and supplies	14,590	13,054
Other	8,444	9,131
Total current assets	130,732	118,601
Property and Equipment:		
Drilling equipment	551,634	508,845
Oil and natural gas properties, on the full cost method:		
Proved properties	816,040	731,622
Undeveloped leasehold not being amortized	36,424	28,170
Gas gathering and processing equipment	50,193	38,417
Transportation equipment	14,975	13,559
Other	11,550	10,946
	1,480,816	1,331,559
Less accumulated depreciation, depletion, amortization and impairment	515,532	466,923
Net property and equipment	965,284	864,636
Goodwill	31,615	30,509
Other Assets	11,503	9,390
Total Assets	$ 1,139,134	$ 1,023,136

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS - CONTINUED

	June 30, 2005 (Unaudited)	December 31, 2004
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of other liabilities	$ 1,239	$ 5,837
Accounts payable	64,936	49,268
Accrued liabilities	25,862	19,818
Income taxes payable	5,047	33
Contract advances	2,677	2,220
Total current liabilities	99,761	77,176
Long-Term Debt	94,900	95,500
Other Long-Term Liabilities	37,760	37,725
Deferred Income Taxes	226,003	204,466
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	---	---
Common stock, $.20 par value, 75,000,000 shares authorized, 45,859,404 and 45,745,399 shares issued, respectively	9,172	9,149
Capital in excess of par value	312,556	310,132
Accumulated other comprehensive income (loss)	(350)	---
Retained earnings	359,332	288,988
Total shareholders' equity	680,710	608,269
Total Liabilities and Shareholders' Equity	$ 1,139,134	$ 1,023,136

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 **Six Months Ended**

	June 30,	June 30,

2005	2004	2005	2004

(In thousands except per share amounts)

Revenues:

Contract drilling	$	105,825	$	67,110	$	202,506	$	130,324

Oil and natural gas	61,976	46,334	118,840	84,324

Gas gathering and processing	21,104	58	39,334	88

Other	962	526	767	902

Total revenues	189,867	114,028	361,447	215,638

Expenses:

Contract drilling:

Operating costs	64,298	48,364	127,729	94,920

Depreciation	10,381	7,754	19,991	15,218

Oil and natural gas:

Operating costs	12,590	10,496	25,003	20,128

Depreciation, depletion

and amortization	14,845	11,535	29,277	21,712

Gas gathering and processing:

Operating costs	19,387	20	36,221	35

Depreciation	727	21	1,365	38

General and administrative	3,160	3,103	7,131	5,874

Interest	585	514	1,272	931

Total expenses	125,973	81,807	247,989	158,856

Income Before Income Taxes	63,894	32,221	113,458	56,782

Income Tax Expense:

Current	12,140	1,556	21,557	2,127

Deferred	12,140	10,751	21,557	19,514

Total income taxes	24,280	12,307	43,114	21,641

Equity in Earnings of

Unconsolidated Investments,

Net of Income Tax	---	270	---	550

Net Income	$ 39,614	$ 20,184	$ 70,344	$ 35,691

Net Income per Common Share:

Basic	$ 0.86	$ 0.44	$ 1.53	$ 0.78

Diluted	$	0.86	$	0.44	$	1.53	$	0.78

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, 2005	Six Months Ended June 30, 2004
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 70,344	$ 35,691
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion and amortization	51,025	37,446
Deferred tax expense	21,557	19,851
Other	1,803	(139)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(12,885)	416
Accounts payable	(37,082)	(1,335)
Material and supplies inventory	(1,536)	(4,224)
Accrued liabilities	6,803	5,303
Contract advances	457	1,091
Other – net	881	74
Net cash provided by operating activities	101,367	94,174
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (including producing property acquisitions and other acquisitions)	(113,481)	(167,620)
Proceeds from disposition of assets	3,563	1,475
Other-net	(43)	1,735
Net cash used in investing activities	(109,961)	(164,410)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(600)	69,600
Net payments of notes payable and other long-term debt	180	(33)
Proceeds from exercise of stock options	559	380
Book overdrafts	9,406	5,470
Net cash from financing activities	9,545	75,417
Net Increase in Cash and Cash Equivalents	951	5,181
Cash and Cash Equivalents, Beginning of Year	665	598
Cash and Cash Equivalents, End of Period	$ 1,616	$ 5,779

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,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In thousands)		
Net Income	$ 39,614	$ 20,184	$ 70,344	$ 35,691
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	1,012	(252)	(452)	(556)
Adjustment reclassification - derivative settlements	74	347	102	425
Comprehensive Income	$ 40,700	$ 20,279	$ 69,994	$ 35,560

The accompanying notes are an integral part of the

consolidated condensed financial statements.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO 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 wholly owned subsidiaries (company) and have been prepared under the rules and regulations of the Securities and Exchange Commission. 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 generally accepted accounting principles. 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 present fairly the interim financial information. Certain reclassifications have been made to prior year financial information to conform to the current period presentation.

Results for the three months and six months ended June 30, 2005 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, 2004. The company's independent registered public accounting firm performed a review of these interim financial statements in accordance with standards of the Public Company Accounting Oversight Board (United States). Under Rule 436(c) under the Securities Act of 1933, their report of that review should not be considered as part of any registration statements prepared or certified by them within the meaning of Section 7 and 11 of that Act and the independent registered public accounting firm's liability under Section 11 does not extend to it.

The company's stock-based compensation plans are accounted for under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense included in reported net income is the company's matching 401(k) contribution. The following table illustrates the effect on net income and earnings per share if the company had applied the fair value recognition provisions of Financial Accounting Standards Board Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In thousands except per share amounts)			
Net Income, as Reported	$ 39,614	$ 20,184	$ 70,344	$ 35,691
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax	397	219	946	438

Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(890)	(627)	(1,920)	(1,140)
Pro Forma Net Income	$ 39,121	$ 19,776	$ 69,370	$ 34,989
Basic Earnings per Share:				
As reported	$ 0.86	$ 0.44	$ 1.53	$ 0.78
Pro forma	$ 0.85	$ 0.43	$ 1.51	$ 0.77
Diluted Earnings per Share:				
As reported	$ 0.86	$ 0.44	$ 1.53	$ 0.78
Pro forma	$ 0.85	$ 0.43	$ 1.51	$ 0.76

The fair value of each option granted is estimated using the Black-Scholes model. There were no options granted in the first quarter of 2004. In the second quarter of 2004, options were granted for 31,500 shares with an estimated fair value of approximately $0.5 million. In the first quarter of 2005 options for 4,000 shares with an estimated fair market value of approximately $0.1 million were granted, and in the second quarter of 2005 options for 54,500 shares with an estimated fair market value of approximately $1.2 million were granted. For options granted in the first and second quarter of 2005, the company's estimate of stock volatility was 0.55 and 0.51, respectively, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 4.42% and 4.35%, respectively. Expected life ranged from 1 to 10 years based on prior experience depending on the vesting periods involved and the make up of participating employees.

NOTE 2 - EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share for the company.

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Three Months Ended June 30, 2005:			
Basic earnings per common share	$ 39,614	45,859	$ 0.86
Effect of dilutive stock options	--	235	--
Diluted earnings per common share	$ 39,614	46,094	$ 0.86

For the Three Months Ended June 30, 2004:			
Basic earnings per common share	$ 20,184	45,723	$ 0.44
Effect of dilutive stock options	--	208	--
Diluted earnings per common share	$ 20,184	45,931	$ 0.44

All of the stock options outstanding at June 30, 2005 and 2004 were included in the computation of diluted earnings per share for the three months ended June 30, 2005 and 2004.

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Six Months Ended June 30, 2005:			
Basic earnings per common share	$ 70,344	45,829	$ 1.53
Effect of dilutive stock options	--	234	--
Diluted earnings per common share	$ 70,344	46,063	$ 1.53
For the Six Months Ended June 30, 2004:			
Basic earnings per common share	$ 35,691	45,697	$ 0.78
Effect of dilutive stock options	--	190	--
Diluted earnings per common share	$ 35,691	45,887	$ 0.78

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, 2005 and 2004 because the option exercise prices were greater than the average market price of common shares:

	2005	2004
Options	---	24,500

Average Exercise Price	$ ---	$ 28.23

NOTE 3 – ACQUISITIONS

On January 5, 2005 the company acquired a subsidiary of Strata Drilling LLC for $10.5 million in cash. In this acquisition the company acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two rigs are 1,500 horsepower, diesel electric rigs with the capacity to drill 12,000 to 20,000 feet. One rig was operating under contract when acquired and the other rig is completing refurbishment for approximately $3.1 million and will be placed in service in August 2005. Both rigs will be used in our Rocky Mountain division. The results of operations for this acquired company are included in the statement of income for the period after January 5, 2005.

The $10.5 million paid in this acquisition was allocated as follows (in thousands):

Rigs	$ 5,712
Spare Drilling Equipment	2,715
Drill Pipe and Collars	932
Goodwill	1,106
Total consideration	$ 10,465

On June 15, 2005, the company completed its acquisition of certain oil and natural gas properties from a private company for a purchase price of $23.1 million in cash. The acquisition consisted of approximately 14.0 Bcfe of proved oil and natural gas reserves and several probable locations. The acquired properties are located in Oklahoma and currently produce 2.5 MMcfe per day. The effective date of the acquisition was April 1, 2005. The results of operations for the acquired properties are included in the statement of income beginning June 1, 2005 with the results for the period from April 1, 2005 through May 31, 2005 included as part of the purchase price. The $23.1 million paid in this acquisition increased our basis in oil and natural gas properties held under the full cost method.

NOTE 4 – CREDIT AGREEMENT

Long-term debt consisted of the following as of June 30, 2005 and December 31, 2004:

	June 30, 2005	December 31, 2004
	(In thousands)	
Revolving Credit Loan, with Interest at June 30, 2005 and December 31, 2004 of 4.2% and 3.1%, Respectively	$ 94,900	$ 95,500
Less Current Portion	--	--

Total Long-Term Debt	$ 94,900	$ 95,500

The company has a revolving $150 million credit facility having a four year term ending January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and the company has elected to have the full $150.0 million available as the commitment amount. The company pays a commitment fee of .375 of 1% for any unused portion of the commitment amount. The company incurred origination, agency and syndication fees of $515,000 associated with the agreement, $40,000 of which will be paid annually. The fees will be amortized over the four year life of the loan.

On June 13, 2005, but effective as of June 1, 2005, the company (including certain of its subsidiaries) and its lenders entered into a first amendment to the credit agreement. The principle change to the credit agreement was to include an amount for the Superior Pipeline Company LLC (Superior) cash flow (as described and defined in the amendment) in the borrowing base provision.

The borrowing base under the current credit facility is subject to re-determination on May 10 and November 10 of each year. Each re-determination is based primarily on the sum of a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of the company's drilling rig fleet, limited to $20 million, and such loan value as the lenders shall reasonably attribute to the Superior cash flow, is added to the borrowing base. The agreement also allows for one requested special re-determination of the borrowing base (by either the lenders or the company) between each scheduled re-determination date if conditions warrant such a request.

At the company's election, any part of the outstanding debt may be fixed at a 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 1.50% depending on the level of debt as a percentage of the total loan value 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 JPMorgan Chase 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.

The credit agreement 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 banks.

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

- consolidated net worth of at least $350 million,
- a current ratio (as defined in the loan agreement) of not less than 1 to 1, and

- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the loan agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On June 30, 2005, the company was in compliance with the covenants in its credit agreement.

<u>NOTE 5 – ASSET RETIREMENT OBLIGATIONS</u>

Under Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations” (FAS 143) the company is required to 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. 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, 2005 and 2004 relating to the company’s retirement obligation for plugging liability:

	Six Months Ended	
	2005	2004
	(In Thousands)	
Short-Term Plugging Liability:		
Liability at beginning of period	$ 226	$ 303
Accretion of discount	12	5
Liability settled in the period	(103)	(67)
Liability sold	---	(21)
Reclassification of liability from long-term to short-term	204	5
Plugging liability at end of period	$ 339	$ 225
Long-Term Plugging Liability:		
Liability at beginning of period	$ 18,909	$ 11,691
Accretion of discount	447	393
Liability incurred in the period	338	5,745
Liability sold	---	(63)
Reclassification of liability from long-term to short-term	(204)	(5)
Revision of estimates	(856)	---
Plugging liability at end of period	$ 18,634	$ 17,761

NOTE 6 - NEW ACCOUNTING PRONOUNCEMENTS

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. The company does not expect this statement to have a material impact on its results of operations, financial condition or cash flows.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended Accounting Principles Board (APB) Opinion No. 29, "Accounting for Non-monetary Transactions." FAS 153 requires that non-monetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at the book value of the assets. This statement is effective for non-monetary transactions occurring in fiscal periods beginning after June 15, 2005. The company does not expect this statement to have a material impact on its results of operations, financial condition or cash flows.

In December 2004, the FASB issued FAS 123R "Share-Based Payment", which requires that compensation cost relating to share-based payments be recognized in the company's financial statements. The company currently accounts for those payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under FAS 123R, the company would have been required to implement the standard as of the beginning of the first interim period that begins after June 15, 2005. On April 15, 2005, the Securities and Exchange Commission (SEC) approved a new rule that allows the implementation of Statement No. 123R at the beginning of the next fiscal year after June 15, 2005 (January 1, 2006 for the company). The company is preparing to implement this standard effective January 1, 2006. On March 29, 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) on FAS 123R to assist preparers by simplifying some on the implementation challenges of FAS123R. Although the transition method to be used to adopt the standard has not been selected, see Note 1 for the effect on net income and earnings per share for the three and six month periods ended June 30, 2005 and 2004 if the company had applied the fair value recognition provision of FAS 123 to stock based employee compensation.

In June 2005, the FASB issued Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections," which establishes new standards on accounting for changes in accounting principles. Pursuant to the new rules, all such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. FAS 154 completely replaces APB 20 and FAS 3, though it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. FAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after May 2005. The application of FAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of FAS 154. The company does not expect this statement to have a material impact on its results of operations, financial condition or cash flows.

NOTE 7 – GOODWILL

Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company, CDC Drilling Company, SerDrilco Incorporated, Sauer Drilling

Company and Strata Drilling LLC over the fair value of the net assets acquired. An impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to the company's drilling segment. In the first quarter of 2005, the carrying amount of goodwill was increased by $1.1 million for the goodwill recorded in the acquisition of Strata Drilling LLC.

NOTE 8 – HEDGING ACTIVITY

The company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on its oil and natural gas production. Such 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.

During the first and second quarters of 2004, the company entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu of production per day. One contract covered the period of April through October of 2004 and had a floor of $4.50 and a ceiling of $6.76. The other contract covered the period of May through October of 2004 and had a floor of $5.00 and a ceiling of $7.00. The company also entered into an oil hedge covering 1,000 barrels of oil production per day. This transaction covered the periods of February through December of 2004 and had an average price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contract and the hedge was recognized on the June 30, 2004 balance sheet as a derivative liability of $0.2 million and at a loss of $0.1 million, net of tax, in accumulated other comprehensive income. Oil revenues were reduced by $0.6 million in the second quarter of 2004 due to the settlement of the oil hedge and oil revenues were reduced by $0.7 million for the six months ended June 30, 2004.

In January 2005, the company entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu of production per day. One contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.19. The other contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.30. In March 2005, the company also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covers the period of April through December of 2005 and has a floor of $45.00 and a ceiling of $69.25. 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, 2005 balance sheet as a derivative liability of $0.5 million and at a loss of $0.3 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. This period coincides with the remaining length of the company's current credit facility. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. The company's interest expense was increased by $0.1 million in the second quarter of 2005 and $0.2 million for the six months ended June 30, 2005. The fair value of the swap was recognized on the June 30, 2005 balance sheet as a derivative liability of $0.1 million and at a loss of $0.1 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 Exploration and Production and Gas Gathering and Processing, representing its 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 Exploration and Production segment is engaged in the development, acquisition and production of oil and natural gas properties and the Gas Gathering and Processing segment is engaged in the purchasing, gathering, processing and treating of natural gas.

The company evaluates the performance of its 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 industry segment for the three and six month periods ended June 30, 2005 and 2004 is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In thousands)			
Revenues:				
Contract drilling	$ 110,098	$ 70,581	$ 209,418	$ 136,161
Elimination of inter-segment revenue	4,273	3,471	6,912	5,837
Contract drilling net of inter-segment revenue	105,825	67,110	202,506	130,324
Oil and natural gas	61,976	46,334	118,840	84,324
Gas gathering and processing	23,038	502	43,126	837
Elimination of inter-segment revenue	1,934	444	3,792	749
Gas gathering and processing net of inter-segment revenue	21,104	58	39,334	88
Other	962	526	767	902
Total revenues	$ 189,867	$ 114,028	$ 361,447	$ 215,638
Operating Income (1):				
Contract drilling	$ 31,146	$ 10,992	$ 54,786	$ 20,186
Oil and natural gas	34,541	24,303	64,560	42,484
Gas gathering and processing	990	17	1,748	15
Total operating income	66,677	35,312	121,094	62,685
General and administrative expense	(3,160)	(3,103)	(7,131)	(5,874)
Interest expense	(585)	(514)	(1,272)	(931)
Other income (expense) - net	962	526	767	902
Income before income taxes	$ 63,894	$ 32,221	$ 113,458	$ 56,782

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

expenses, interest expense or income taxes.

NOTE 10 – SUBSEQUENT EVENT

On August 5, 2005, the company's wholly owned subsidiary, Unit Drilling Company, signed a purchase and sale agreement to acquire seven drilling rigs from Texas Wyoming Drilling, Inc., a Texas-based privately-owned company. The purchase price of the acquisition is $32 million, $20 million to be paid in cash and $12 million to be issued in stock. The acquisition is anticipated to close on or before August 31, 2005.

Of the seven drilling rigs, five are currently operating under contract and two are in the process of refurbishment and are anticipated to be operational before the closing date. Six of the seven drilling rigs are mechanical, with one being a diesel electric rig. The rigs range from 400 to 1,700 horsepower. The rigs are active in the Barnett Shale area of North Texas.

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, 2005, and the related consolidated condensed statements of income and comprehensive income for each of the three and six month periods ended June 30, 2005 and 2004 and the consolidated condensed statements of cash flows for the six month periods ended June 30, 2005 and 2004. 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, 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, 2004, and the related consolidated statements of income, shareholders' equity and of cash flows for the year then ended, management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the company's internal control over financial reporting as of December 31, 2004; and in our report dated March 14, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated condensed balance sheet as of December 31, 2004, 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 8, 2005

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

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 agreement. 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 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.

At June 30, 2005, we had cash totaling $1.6 million and we had borrowed $94.9 million of the $150.0 million we had elected to have available under our credit agreement. On August 5, 2005, our wholly owned subsidiary Unit Drilling Company signed a purchase agreement to acquire seven drilling rigs from Texas Wyoming Drilling, Inc., a Texas-based privately-owned company. The purchase price of this acquisition is $32 million, with $20 million to be paid in cash financed through our credit agreement and the remaining $12 million paid through the issuance of our common stock.

Our three principal business segments are:

- contract drilling carried out by our subsidiaries Unit Drilling Company and Service Drilling Southwest, L.L.C.;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company and, until it was merged into Unit Petroleum Company in March 2005, PetroCorp Incorporated; and
- natural gas purchasing, gathering and processing carried out by our subsidiary Superior Pipeline Company, L.L.C.

The following is a summary of certain financial information on June 30, 2005 and June 30, 2004 and for the six months ended June 30, 2005 and June 30, 2004:

	June 30, 2005	June 30, 2004	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 30,971	$ 26,970	15%
Long-Term Debt	$ 94,900	$ 70,000	36%
Shareholders' Equity	$ 680,710	$ 553,114	23%
Ratio of Long-Term Debt to Total Capitalization	12%	11%	
Net Income	$ 70,344	$ 35,691	97%
Net Cash Provided by Operating Activities	$ 101,367	$ 94,174	8%
Net Cash Used in Investing Activities	$ (109,961)	$ (164,410)	33%
Net Cash Provided by Financing Activities	$ 9,545	$ 75,417	(87%)

The following table summarizes certain operating information for the first six months of 2005 and 2004:

	June 30, 2005	June 30, 2004	Percent Change
Oil Production (MBbls)	537	494	9%
Natural Gas Production (MMcf)	15,514	12,908	20%
Average Oil Price Received	$ 45.15	$ 30.91	46%
Average Oil Price Received Excluding Hedge	$ 45.15	$ 32.30	40%
Average Natural Gas Price Received	$ 5.98	$ 5.24	14%
Average Natural Gas Price Received Excluding Hedge	$ 5.98	$ 5.24	14%
Average Number of Our Drilling Rigs in Use During the Period	99.8	82.6	21%
Total Number of Our Drilling Rigs Available at the End of the Period	103.0	89.0	16%
Gas Gathered - MMBtu/day	114,472	23,719	383%
Gas Processed - MMBtu/day	31,005	63	49,114%
Number of Natural Gas Gathering Systems	35	18	94%

Our Bank Credit Agreement. At June 30, 2005, we had a $150.0 million bank credit agreement consisting of a revolving credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and we currently elected to have the full $150.0 million available as the commitment amount. We are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We incurred origination, agency and syndication fees of $515,000 associated with the new agreement, $40,000 of which will be paid annually. The remainder of the fees will be amortized over the four year life of the loan. The average interest rate for the first six months of 2005 was 4.2% including the interest incurred from the settlement of our interest rate swap. At June 30, 2005 and August 2, 2005 our borrowings were $94.9 million and $89.8 million, respectively.

On June 13, 2005, but effective as of June 1, 2005, the company (including certain of its subsidiaries) and its lenders entered into a first amendment to the credit agreement. The principle change to the credit agreement was to include an amount for the Superior cash flow (as described and defined in the amendment) in the borrowing base provision.

The borrowing base under our credit facility is subject to re-determination on May 10 and November 10 of each year. The latest re-determination supported the full $150.0 million. Each re-determination is based primarily on the sum of a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of our drilling rig fleet, limited to $20 million, and such loan value as the lenders shall reasonably attribute to the Superior cash flow, is added to the borrowing base. The agreement also allows for one requested special re-determination of the borrowing base (by either the lenders or us) between each scheduled re-determination date if conditions warrant such a request.

At our election, any part of the outstanding debt may be fixed at a 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 1.50% depending on the level of debt as a percentage of the total loan value 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 JPMorgan Chase 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.

The credit agreement 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 the company's banks.

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

- consolidated net worth of at least $350 million,

- a current ratio (as defined in the loan agreement) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the loan agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

We were in compliance with the covenants of our credit agreement as of June 30, 2005.

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. This period coincides with the remaining length of our current credit facility. The fixed rate is 3.99%. The swap is a cash flow hedge. As a result of our hedge, our interest expense was increased by $0.1 million in the second quarter of 2005 and by $0.2 million for the six months ended June 30, 2005. The fair value of the swap was recognized on the June 30, 2005 balance sheet as a derivative liability of $0.1 million and at a loss of $0.1 million, net of tax, in accumulated other comprehensive income.

Contractual Commitments. At June 30, 2005 we have the following contractual obligations:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Bank Debt (1)	$ 104,426	$ 3,872	$ 100,554	$ ---	$ ---
Retirement Agreements (2)	2,075	350	1,300	425	---
Operating Leases (3)	3,665	1,074	1,580	1,011	---
Drill Pipe, Drilling Rigs and Equipment Purchases (4)	31,182	31,182	---	---	---
Casing Purchases (5)	1,615	1,615	---	---	---
Derivative Contracts (6)	564	512	52	---	---
Total Contractual Obligations	$ 143,527	$ 38,605	$ 103,486	$ 1,436	$ ---

(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt. This obligation is presented in accordance with the terms of the credit agreement signed on January 30, 2004 and includes interest calculated at the June 30, 2005 interest rate of 4.2% including the effect of the interest rate swap related to $50.0 million of debt outstanding.

(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 payment 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; Pinedale, Wyoming and Denver, Colorado under the terms of operating leases expiring through January 31, 2010. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess rig equipment and production inventory.

(4) Due to the potential for limited availability of new drill pipe within the industry, we have a commitment to purchase approximately $12.8 million of drill pipe and drill collars. We have also committed to purchase $3.2 million of additional rig components for the construction of new rigs and have committed $15.2 million

for the purchase of two drilling rigs with a 30% down payment in the third quarter of 2005 and the remainder at delivery in the first quarter of 2006.

(5) Our oil and natural gas segment has a commitment to purchase $1.6 million of intermediate and tie-back casing for delivery during the third quarter of 2005.

(6) We have recorded a $0.5 million liability for the market-to-market value associated with our oil and natural gas collar contracts and a $0.1 million liability for the market-to-market value associated with our interest rate swap. These transactions are discussed further under the hedging section below.

At June 30, 2005, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Amount of Commitment Expiration Per Period			
Other Commitments	Total Amount Committed Or Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred Compensation Agreement (1)	$ 2,351	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement (2)	$ 2,858	$ 599	$ 129	Unknown	Unknown
Plugging Liability (3)	$ 18,973	$ 339	$ 1,352	$ 1,047	$ 16,235
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$ 18,280	$ 6,393	$ 1,955	$ 1,153	$ 8,779

(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. As of June 30, 2005, there were no participants in the Special Plan.

(3) On January 1, 2003 we adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled or acquired).

(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 2004, 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. Repurchases of $14,000 and $4,000 were made in the first six months of 2004 and 2005, respectively.

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

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

During the first and second quarters of 2004, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu of production per day. One contract covered the period of April through October of 2004 and had a floor of $4.50 and a ceiling of $6.76. The other contract covered the period of May through October of 2004 and had a floor of $5.00 and a ceiling of $7.00. We also entered into an oil hedge covering 1,000 barrels of oil production per day. This transaction covered the periods of February through December of 2004 and had an average price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contract and the hedge was recognized on the June 30, 2004 balance sheet as a derivative liability of $0.2 million and at a loss of $0.1 million, net of tax, in accumulated other comprehensive income. Oil revenues were

reduced by $0.6 million for the second quarter of 2004 due to the settlement of the oil hedge, and oil revenues were reduced by $0.7 million for the six months ended June 30, 2004.

In January 2005, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu of production per day. One contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.19. The other contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.30. In March 2005, we also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covers the periods of April through December of 2005 and has a floor of $45.00 and a ceiling of $69.25. 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, 2005 balance sheet as a derivative liability of $0.5 million and at a loss of $0.3 million, net of tax, in accumulated other comprehensive income.

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. This period coincides with the remaining term of our current credit facility. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. Our interest expense was increased by $0.1 million in the second quarter of 2005 and $0.2 million for the six months ended June 30, 2005 as a result of the interest rate swap. The fair value of the swap was recognized on the June 30, 2005 balance sheet as a derivative liability of $0.1 million and at a loss of $0.1 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 and employee medical benefits. Our insurance policies contain deductibles or retentions per occurrence ranging from $0.2 million for general liability to $1.0 million for 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 claims. There is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco we have continued to use its ERISA governed occupational injury benefit plan to cover its employees 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 month 2005 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $244,200 per month ($2.9 million annualized) change in our pre-tax operating cash flow. Our first six month 2005 average natural gas price was $5.98 compared to an average natural gas price of $5.24 for the first six months of 2004. A $1.00 per barrel change in our oil price would have a $84,100 per month ($1.0 million annualized) change in our pre-tax operating cash flow based on our production in the first six months of 2005. Our first six month 2005 average oil price was $45.15 compared with an average oil price of $30.91 received in the first six months of 2004.

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 agreement 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. Presently we believe that our buyers will be able to perform their commitments to us.

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 83 wells (28.61 net wells) in the first six months of 2005 compared to 73 wells (34.62 net wells) in the first six months of 2004. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first six months of 2005 totaled $92.8 million. Based on current prices, we plan to drill an estimated 220 to 230 wells in 2005 and estimate our total capital expenditures for oil and natural gas exploration and acquisitions to be approximately $156.0 million excluding the $23.1 million paid for producing properties in the second quarter of 2005. We have commitments to purchase $1.6 million of intermediate and tie-back casing for delivery during the third quarter of 2005.

On June 15, 2005, we completed the acquisition of certain oil and natural gas properties from a private company for an adjusted purchase price of $23.1 million in cash. The acquisition consisted of approximately 14.0 Bcfe of proved oil and natural gas reserves and several probable locations. The properties are located in Oklahoma and currently produce 2.5 MMcfe per day. The acquisition had an effective date of April 1, 2005. The results of operations for the acquired properties are included in the statement of income beginning June 1, 2005 with the results for the period from April 1, 2005 through May 31, 2005 included as part of the adjusted 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. Because of the current high demand for drilling rigs, we are experiencing some difficulty in hiring and keeping all of the rig crews we need.

In response, at the end of the first and fourth quarters of 2004, we increased wages in some of our drilling areas and implemented longevity pay incentives to help maintain our contract drilling labor base. At the end of the second quarter of 2005, we increased wages in our

drilling areas that had not received increases in the fourth quarter of 2004. To date, these efforts have allowed us to meet our labor requirements. If current demand for drilling rigs continues, shortages of experienced personnel may limit our ability to operate our drilling rigs at or above the 98% utilization rate we achieved in the first six months of 2005.

We currently do not have any shortages of drill pipe and drilling equipment. Because of increasing steel costs and the potential for shortages in the availability of new drill pipe, at June 30, 2005 we had commitments to purchase approximately $12.8 million of drill pipe and drill collars. We have also committed to purchase $3.2 million of additional rig components for the construction of new drilling rigs and $15.2 million for the purchase of two new drilling rigs which will be delivered in the first quarter of 2006. A down payment of 30% of the purchase price for the two new rigs will be made during the third quarter of 2005.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices influence the demand for our drilling rigs and the prices we can charge for our contract drilling services. The average rates we received for our drilling rigs during 2003 and 2004 reached a low of $7,275 per day in February of 2003. However, as natural gas and oil prices began to rise during the second quarter of 2003 and have continued to remain strong through the first six months of 2005, both demand for our drilling rigs and dayrates have improved. In the first six months of 2005, the average dayrate we received was $10,782 per day compared to $8,507 per day in the first six months of 2004. The average use of our drilling rigs in the first six months of 2005 was 99.8 drilling rigs (98%) compared with 82.6 rigs (94%) for the first six months of 2004. Based on the average utilization of our drilling rigs during the first quarter of 2005, a $100 per day change in dayrates has a $9,980 per day ($3.6 million annualized) change in our pre-tax operating cash flow. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiary provides 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 2005 and 2004, we drilled 24 and 17 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $2.4 million and $2.0 million during the six months of 2005 and 2004, 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. On January 5, 2005, we acquired a subsidiary of Strata Drilling LLC for $10.5 million in cash. This acquisition included two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two drilling rigs are 1,500 horsepower, diesel electric rigs with the capacity to drill 12,000 to 20,000 feet. One drilling rig was operating under contract when it was acquired and the other drilling rig is completing refurbishment for approximately $3.1 million and will be placed in service in August 2005. Both rigs will be in our Rocky Mountain division. The results of operations for this acquired company are included in the statement of income for the period after January 5, 2005.

On July 30, 2004, we completed our acquisition of Sauer Drilling Company, a Casper,

Wyoming-based drilling company. We paid $40.3 million in this acquisition which included $5.3 million for working capital. This acquisition includes nine drilling rigs, a fleet of trucks, and an equipment and repair yard with associated inventory, located in Casper, Wyoming. The rigs range from 500 horsepower to 1,000 horsepower with depth capacities rated from 5,000 feet to 16,000 feet. The fleet of trucks consists of four vacuum trucks and 11 rig-up trucks used to move the rigs to new drilling locations. The trucks also have the capacity to move third-party rigs. This acquisition increased our market share in the Rocky Mountains in the medium-to-smaller drilling rig depth ranges. The Casper, Wyoming equipment yard will continue to provide service space for the nine newly acquired drilling rigs and trucks as well as for our existing Rocky Mountain rig fleet. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004.

On May 4, 2004, we acquired two drilling rigs and related equipment for $5.5 million. The drilling rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. We refurbished the drilling rigs for approximately $4.0 million. One drilling rig was placed into service at the beginning of August 2004 and the other drilling rig was placed into service in the middle of September 2004. Both drilling rigs are working in our Rocky Mountain division.

For our contract drilling operations, during the first six months of 2005, we incurred $51.7 million in capital expenditures, which includes $1.1 million in goodwill from the Strata Drilling LLC acquisition. For the year 2005, we have budgeted capital expenditures of approximately $69.0 million for our contract drilling operations. This amount excludes the $10.5 million paid in the Strata Drilling LLC acquisition, the estimated $13.2 million associated with two rigs to be constructed by us and placed in service during the first quarter of 2006 and the $15.2 million purchase price of the two rigs to be purchased from an outside party for delivery in the first quarter of 2006.

On August 5, 2005, our wholly owned subsidiary, Unit Drilling Company, signed a purchase and sale agreement to acquire seven drilling rigs from Texas Wyoming Drilling, Inc., a Texas-based privately-owned company. The purchase price of the acquisition is $32 million, $20 million to be paid in cash and $12 million to be issued in stock. The acquisition is anticipated to close on or before August 31, 2005.

Of the seven drilling rigs, five are currently operating under contract and two are in the process of refurbishment and are anticipated to be operational before the closing date. Six of the seven drilling rigs are mechanical, with one being a diesel electric rig. The rigs range from 400 to 1,700 horsepower. The rigs are active in the Barnett Shale area of North Texas. At the closing of this acquisition our rig fleet will consist of 111 drilling rigs.

Acquisition of Natural Gas Gathering and Processing Company. In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior Pipeline Company, L.L.C. we did not already own. We paid $19.8 million in this acquisition. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas. It operates one natural gas treatment plant, owns four processing plants, 35 active gathering systems and 480 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana and has been in

business since 1996. This acquisition and consolidation increases our ability to gather and market our natural gas (as well as third party natural gas) and construct or acquire existing natural gas gathering and processing facilities.

Before this acquisition, our 40% interest in the operations of Superior was shown as equity in earnings of unconsolidated investments. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. During the six months of 2005, Superior purchased $2.7 million of our natural gas production, provided gathering and transportation services of $1.1 million and paid $0.1 million for our natural gas liquids which were eliminated from our consolidated condensed financial statements.

During the first six months of 2005 we incurred $11.8 million in capital expenditures for our natural gas gathering and processing segment and for the year 2005 we have budgeted capital expenditures of approximately $20.0 million with the focus 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 11 oil and natural gas limited partnerships which were formed privately and publicly. 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 2004, the total paid to us for all of these fees was $0.7 million. We expect the fees in 2005 will be comparable to those in 2004. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. We do not expect this statement to have a material impact on our results of operations, financial condition or cash flows.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended Accounting Principles Board (APB) Opinion No. 29, "Accounting for Non-monetary Transactions." FAS 153 requires that non-monetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for non-monetary transactions occurring in fiscal periods beginning after June 15, 2005. We do not

expect this statement to have a material impact on our results of operations, financial condition or cash flows.

In December 2004, the FASB issued FAS 123R, which requires that compensation cost relating to share-based payments be recognized in our financial statements. We currently account for those payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under Statement No. 123R, we would have been required to implement the standard as of the beginning of the first interim period that begins after June 15, 2005. On April 15, 2005, the Securities and Exchange Commission (SEC) approved a new rule that allows the implementation of Statement No. 123R at the beginning of the next fiscal year that begins after June 15, 2005 (January 1, 2006 for us). We are preparing to implement this standard effective January 1, 2006. On March 29, 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) on FAS 123R to assist preparers by simplifying some on the implementation challenges of FAS123R. Although the transition method to be used to adopt the standard has not been selected, see Note 1 for the effect on net income and earnings per share for the three and six months ended June 30, 2005 and 2004 if we had applied the fair value recognition provision of FAS 123 to stock based employee compensation.

In June 2005, the FASB issued Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections," which establishes new standards on accounting for changes in accounting principles. Pursuant to the new rules, all such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. FAS 154 completely replaces APB 20 and FAS 3, though it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. FAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after May 2005. The application of FAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of FAS 154. We do not expect this statement to have a material impact on our results of operations, financial condition or cash flows.

RESULTS OF OPERATIONS

Quarter Ended June 30. 2005 versus Quarter Ended June 30, 2004

Provided below is a comparison of selected operating and financial data for the second quarter of 2005 versus the second quarter of 2004:

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Percent Change
Total Revenue	$ 189,867,000	$ 114,028,000	67%
Net Income	$ 39,614,000	$ 20,184,000	96%
Oil and Natural Gas:			
Revenue	$ 61,976,000	$ 46,334,000	34%
Operating costs	$ 12,590,000	$ 10,496,000	20%
Average natural gas price (Mcf)	$ 6.27	$ 5.57	13%
Average oil price (Bbl)	$ 45.79	$ 31.12	47%
Natural gas production (Mcf)	7,861,000	6,614,000	19%
Oil production (Bbl)	257,000	278,000	(8%)
Depreciation, depletion and amortization rate (Mcfe)	$ 1.57	$ 1.38	14%
Depreciation, depletion and amortization	$ 14,845,000	$ 11,535,000	29%
Drilling:			
Revenue	$ 105,825,000	$ 67,110,000	58%
Operating costs	$ 64,298,000	$ 48,364,000	33%
Percentage of revenue from daywork contracts	100%	100%	
Average number of rigs in use	100.3	83.7	20%
Average dayrate on daywork contracts	$ 11,298	$ 8,751	29%
Depreciation	$ 10,381,000	$ 7,754,000	34%
Gas Gathering and Processing:			
Revenue	$ 21,104,000	$ 58,000	36,286%
Operating costs	$ 19,387,000	$ 20,000	96,835%
Depreciation	$ 727,000	$ 21,000	3,362%
Gas gathered – MMbtu/day	121,611	25,331	380%
Gas processed – MMbtu/day	31,670	63	50,170%
General and Administrative Expense	$ 3,160,000	$ 3,103,000	2%

Interest Expense	$ 585,000	$ 514,000	14%
Average Interest Rate	4.64%	2.21%	110%
Average Long-Term Debt Outstanding	$ 84,267,000	$ 75,211,000	12%

Oil and natural gas revenues increased $15.6 million or 34% in the second quarter of 2005 as compared to the second quarter of 2004. Increased oil and natural gas prices accounted for 59% of the increase while increased equivalent natural gas production volumes accounted for 40% of the increase. In the second quarter of 2005, natural gas production increased by 19%

while oil production decreased 8%. Increased natural gas production came primarily from our ongoing development drilling activity.

Oil and natural gas operating costs increased $2.1 million or 20% in the second quarter of 2005 as compared to 2004. An increase in the average cost per equivalent Mcf produced represented 32% of the increase in production costs with the remaining 68% of the increase attributable to the increase in volumes produced primarily from development drilling. Lease operating expenses represented 40% of the increase, gross production taxes 44% and general and administrative cost directly related to oil and natural gas production 16%. Operating costs per well increased, resulting in an increase in total lease operating expenses, while lease operating expenses per Mcfe remained essentially unchanged due to increases in natural gas production between the comparative quarters. Gross production taxes increased from both increases in the tax rate per Mcfe produced and from the additional natural gas volumes produced between the comparative quarters. General and administrative expenses increased as labor costs increased primarily attributable to a 31% increase in the number of employees working in the exploration and production area. Total depreciation, depletion and amortization (“DD&A”) increased $3.3 million or 29%. Higher production volumes accounted for 48% of the increase while increases in our DD&A rate represented 52% of the increase. The increase in our DD&A rate in the second quarter of 2005 compared to the second quarter of 2004 resulted primarily from an increase in finding cost of 21% experienced in 2004 and a 3% increase in finding cost incurred in the first six months of 2005 compared to the finding cost incurred 2004.

Industry demand for our drilling rigs increased throughout 2004 and the first six months of 2005 as natural gas prices continued to remain above $4.50. Drilling revenues increased $38.7 million or 58% in the second quarter of 2005 versus the second quarter of 2004. In July 2004, we added nine drilling rigs with the acquisition of Sauer Drilling Company. In addition to the Sauer drilling rigs, we also placed five additional drilling rigs in service since the second quarter of 2004. The 14 additional rigs increased our second quarter 2005 drilling revenues by approximately 22%. The increase in revenue from the acquired drilling rigs, the constructed drilling rigs and the increase in utilization of our previously owned drilling rigs represented 34% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 66% of the increase in total drilling revenues. Our average dayrate in the second quarter of 2005 was 29% higher than in the second quarter of 2004.

Drilling operating costs increased $15.9 million or 33% between the comparative quarters. The increase in operating costs from the 14 drilling rigs placed in service since the second quarter of 2004 and increased utilization of our previously owned drilling rigs represented 60% of the total increase in operating cost. Increases in operating cost per day accounted for 40% of the increase in total operating costs. Operating cost per day increased $698 in the second quarter of 2005 when compared with the second quarter of 2004. Approximately $460 of the increase was attributable to costs directly associated with the drilling of wells with increases in labor cost the primary reason for the increase. Indirect drilling costs made up most of the remainder of the increase in per day costs and consisted primarily of property taxes, safety related expenses, repairs, and the implementation of a central hiring system for our Oklahoma drilling rigs. We expect the demand for drilling rigs to remain high throughout 2005 and this demand will result in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in 2004 or in the first six months of 2005. Contract drilling depreciation increased $2.6 million or 34%. The addition of the 14 drilling rigs placed in service since the second quarter of 2004 increased depreciation $1.0 million or 13% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior we did not already own. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior's operations. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas and operates one natural gas treatment plant and owns four processing plants, 35 active gathering systems and 480 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana.

Before the Superior acquisition, our 40% interest in the income or loss from the operations of Superior was shown as equity in earnings of unconsolidated investments and was $0.3 million net of income tax in the second quarter of 2004. The results of operations for Superior are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. Our natural gas gathering and processing revenues, operating expenses and depreciation were $21.0 million, $19.4 million and $0.7 million higher in the second quarter of 2005 versus 2004, respectively, all due to the Superior acquisition.

Total interest expense increased 14% between the comparative quarters. Average debt outstanding was higher in the second quarter of 2005 as compared to the second quarter of 2004 due to the acquisition of Strata Drilling LLC and the acquisition of oil and natural gas properties in the second quarter of 2005. Average debt outstanding accounted for approximately 9% of the interest expense increase with 21% of the increase resulting from the settlement of the interest rate swap and 70% resulting from an increase in average interest rates on our bank debt. Associated with our increased level of development of oil and natural gas properties and the construction of additional drilling rigs and natural gas gathering systems, we capitalized $0.5 million of interest in the second quarter of 2005. No interest was capitalized in 2004.

Income tax expense increased $12.0 million or 97% due to the increase in income before income taxes. Our effective tax rate for the second quarter of 2005 was 38.0% versus 38.2% in the second quarter of 2004. With our increase in income and the reduction of a majority of our net operating loss carryforwards in prior periods, the portion of our taxes reflected as current income tax expense has increased in the second quarter of 2005 when compared with the second quarter of 2004. Current tax expense for the second quarter of 2005 and 2004 was $12.1 million and $1.6 million, respectively. Income tax amounts paid in the second quarter of 2005 were $16.2 million.

Six Months Ended June 30, 2005 versus Six Months Ended June 30, 2004

Provided below is a comparison of selected operating and financial data for the first six months of 2005 versus the first six months of 2004:

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	Percent Change

Total Revenue	$ 361,447,000	$ 215,638,000	68%
Net Income	$ 70,344,000	$ 35,691,000	97%
Oil and Natural Gas:			
Revenue	$ 118,840,000	$ 84,324,000	41%
Operating costs	$ 25,003,000	$ 20,128,000	24%
Average natural gas price (Mcf)	$ 5.98	$ 5.24	14%
Average oil price (Bbl)	$ 45.15	$ 30.91	46%
Natural gas production (Mcf)	15,514,000	12,908,000	20%
Oil production (Bbl)	537,000	494,000	9%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.55	$ 1.36	14%
Depreciation, depletion and amortization	$ 29,277,000	$ 21,712,000	35%
Drilling:			
Revenue	$ 202,506,000	$ 130,324,000	55%
Operating costs	$ 127,729,000	$ 94,920,000	35%
Percentage of revenue from daywork contracts	100%	100%	
Average number of rigs in use	99.8	82.6	21%
Average dayrate on daywork contracts	$ 10,782	$ 8,507	27%
Depreciation	$ 19,991,000	$ 15,218,000	31%
Gas Gathering and Processing:			
Revenue	$ 39,334,000	$ 88,000	44,598%
Operating costs	$ 36,221,000	$ 35,000	103,389%
Depreciation	$ 1,365,000	$ 38,000	3,492%
Gas gathered – MMbtu/day	114,472	23,719	383%
Gas processed – MMbtu/day	31,005	63	49,114%
General and Administrative Expense	$ 7,131,000	$ 5,874,000	21%
Interest Expense	$ 1,272,000	$ 931,000	37%
Average Interest Rate	4.21%	2.20%	91%
Average Long-Term Debt Outstanding	$ 90,537,000	$ 65,615,000	38%

Oil and natural gas revenues increased $34.5 million or 41% in the first six months of 2005 as compared to the first six months of 2004. Increased oil and natural gas prices accounted for 55% of the increase while increased production volumes accounted for 44% of the increase. Increased production came primarily from our ongoing development drilling activity.

Oil and natural gas operating costs increased $4.9 million or 24% in the first six months of 2005 as compared to 2004. An increase in the average cost per equivalent Mcf produced represented 25% of the increase in production costs with the remaining 75% attributable to the increase in volumes produced primarily from development drilling. Lease operating expenses represented 45% of the increase, gross production taxes 40% and general and administrative cost directly related to oil and natural gas production

15%. Operating costs per well increased, resulting in an increase in total lease operating expenses, while lease operating expenses per Mcfe remained essentially unchanged due to increases in natural gas production between the comparative six month periods. Gross production taxes increased from both increases in the tax rate per Mcfe produced and from the additional natural gas volumes produced between the comparative six month periods. General and administrative expenses increased as labor costs increased primarily attributable to a 28% increase in the number of employees working in the exploration and production area. Total DD&A increased $7.6 million or 35%. Higher production volumes accounted for 52% of the increase while increases in our DD&A rate represented 48% of the increase. The increase in our DD&A rate in the first six months of 2005 compared to the first six months of 2004 resulted primarily from an increase in finding cost of 21% experienced in 2004 and a 3% increase in finding cost incurred in the first six months of 2005 compared to the finding cost incurred 2004.

Industry demand for our drilling rigs increased throughout 2004 and the first six months of 2005 as natural gas prices continued to remain above $4.50. Drilling revenues increased $72.2 million or 55% in the first six months of 2005 versus the first six months of 2004. In July 2004, we added nine drilling rigs with the acquisition of Sauer Drilling Company. In addition to the Sauer drilling rigs, we also placed five additional drilling rigs in service since the first six months of 2004. The 14 additional rigs increased our first six months of 2005 drilling revenues by approximately 22%. The increase in revenue from the acquired drilling rigs, the constructed drilling rigs and the increase in utilization of our previously owned drilling rigs represented 36% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 64% of the increase in total drilling revenues. Our average dayrate in the first six months of 2005 was 27% higher than in the first six months of 2004.

Drilling operating costs increased $32.8 million or 35% between the comparative quarters. The increase in operating costs from the 14 drilling rigs placed in service since the first six months of 2004 and increased utilization of our previously owned drilling rigs represented 58% of the total increase in operating cost. Increases in operating cost per day accounted for 42% of the increase in total operating costs. Operating cost per day increased $766 per day in the first six months of 2005 when compared with the first six months of 2004. Approximately $533 of the increase was attributable to costs directly associated with the drilling of wells with increases in labor cost the primary reason for the increase. Indirect drilling costs made up most of the remainder of the increase in per day costs and consisted primarily of property taxes, safety related expenses, repairs and the implementation of a central hiring system for our Oklahoma drilling rigs. We expect the demand for drilling rigs to remain high throughout 2005 and this demand will result in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in 2004 or in the first six months of 2005. Contract drilling depreciation increased $4.8 million or 31%. The addition of the 14 drilling rigs placed in service since the first six months of 2004 increased depreciation $2.0 million or 13% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior we did not already own. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior's operations. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas and operates one natural gas treatment plant and owns four processing plants, 35 active gathering systems and 480 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana.

Before the Superior acquisition, our 40% interest in the income or loss from the operations of Superior was shown as equity in earnings of unconsolidated investments and was $0.6 million net of income tax in the first six months of 2004. The results of operations for Superior are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. Our natural gas gathering and processing revenues, operating expenses and depreciation were $39.2 million, $36.2 million and $1.3 million higher in the first six months of 2005 versus 2004, respectively, all due to the Superior acquisition.

General and administrative expense increased $1.3 million or 21%. Increases in office cost due to growth within the company and increase in external auditing cost along with a $0.7 million increase in personnel cost from the recognition of a liability associated with the retirement of Mr. John Nikkel from his position as Chief Executive Officer all contributed to the increase.

Total interest expense increased $0.3 million or 37%. Average debt outstanding was higher in the first six months of 2005 as compared to the first six months of 2004 due to the PetroCorp, Superior, Sauer Drilling and Strata Drilling acquisitions and the acquisition of certain oil and natural gas properties in 2004 and 2005. Average debt outstanding accounted for approximately 27% of the interest expense increase with 14% of the increase resulting from the settlement of the interest rate swap and 59% resulting from an increase in average interest rates on our bank debt. Associated with our increased level of development of oil and natural gas properties and the construction of additional drilling rigs and natural gas gathering systems, we capitalized $0.8 million of interest in the first six months of 2005. No interest was capitalized in 2004.

Income tax expense increased $21.5 million or 99% due to the increase in income before income taxes. Our effective tax rate for the first six months of 2005 was 38.0% versus 38.1% in the first six months of 2004. With our increase in income and the reduction of a majority of our net operating loss carryforwards in prior periods, the portion of our taxes reflected as current income tax expense has increased in the first six months of 2005 when compared with the first six months of 2004. Current tax expense for the first six months of 2005 and 2004 was $21.6 million and $2.1 million, respectively. Income tax amounts paid in the first six months of 2005 were $16.2 million.

Item 3. Quantitative and Qualitative Disclosures 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. The price we receive is 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 2005 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $0.2 million per month ($2.9 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $0.1 million per month ($1.0 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.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the JPMorgan Chase 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. Historically, we have not used any financial instruments, such as interest rate swaps, to manage our exposure to possible increases in interest rates. However, 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 2005, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $0.4 million.

Item 4. 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 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries).

There were no changes in the company's internal controls or in other factors that could significantly affect these internal controls subsequent to the date of our most recent evaluation.

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;
- wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- business strategy;
- production of oil and natural gas reserves;
- growth potential for our gathering and processing operations;
- gathering systems and processing plants to be constructed or acquired;
- 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. 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.

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the preceding discussion outlines certain factors that in the future could cause our consolidated results for 2005 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

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 Securities and Exchange Commission. We encourage you to get and read that document.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

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 4, 2005 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 Nominees: King P. Kirchner, Don Cook and J. Michael Adcock

Nominee	Numbers of Votes For	Ag W
King P. Kirchner	41,315,312	9
Don Cook	41,652,735	5
J. Michael Adcock	41,762,001	4

The following directors, whose term of office did not expire at the annual meeting, continue as directors of the Company: John G. Nikkel, Mark E. Monroe, William B. Morgan, John H. Williams and Larry D. Pinkston.

II. Ratification of the appointment of PricewaterhouseCoopers L L P as the Company's independent registered public accounting firm for the fiscal year 2005.

For -	41,311,649
Against -	917,130
Abstain -	19,372

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 8, 2005	By:	/s/ Larry I
			LARRY D. PINKSTON Chief Executive Officer and Director
Date:	August 8, 2005	By:	/s/ David
			DAVID T. MERRILL Chief Financial Officer and Treasurer