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 September 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	**46,138,393**

Class	Outstanding at November 1, 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 (UNAUDITED)

	September 30, 2005	December 31, 2004
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 728	$ 665
Restricted cash	17	2,571
Accounts receivable	140,922	93,180
Materials and supplies	11,854	13,054
Other	11,281	9,131
Total current assets	164,802	118,601
Property and Equipment:		
Drilling equipment	599,011	508,845
Oil and natural gas properties, on the full cost method:		
Proved properties	850,365	731,622
Undeveloped leasehold not being amortized	47,596	28,170
Gas gathering and processing equipment	56,111	38,417
Transportation equipment	15,454	13,559
Other	12,212	10,946
	1,580,749	1,331,559
Less accumulated depreciation, depletion, amortization and impairment	541,321	466,923
Net property and equipment	1,039,428	864,636
Goodwill	32,015	30,509
Other Assets	16,402	9,390
Total Assets	$ 1,252,647	$ 1,023,136

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

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

	September 30,	December 31,

	2005	2004
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of other liabilities	$ 7,552	$ 5,837
Accounts payable	68,030	49,268
Accrued liabilities	24,424	19,818
Income taxes payable	4,464	33
Contract advances	3,334	2,220
Total current liabilities	107,804	77,176
Long-Term Debt	115,600	95,500
Other Long-Term Liabilities	39,470	37,725
Deferred Income Taxes	239,971	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, 46,136,293 and 45,745,399 shares issued, respectively	9,227	9,149
Capital in excess of par value	325,070	310,132
Accumulated other comprehensive income (loss)	(1,465)	---
Retained earnings	416,970	288,988
Total shareholders' equity	749,802	608,269
Total Liabilities and Shareholders' Equity	$ 1,252,647	$ 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	Nine Months Ended

	September 30,	September 30,

2005	2004	2005	2004

(In thousands except per share amounts)

Revenues:

Contract drilling	$ 119,873	$ 80,887	$ 322,379	$ 211,211

Oil and natural gas	83,979	46,394	202,819	130,718

Gas gathering and processing	26,561	11,474	65,895	11,562

Other	635	4,595	1,402	5,497

Total revenues	231,048	143,350	592,495	358,988

Expenses:

Contract drilling:

Operating costs	67,161	57,816	194,890	152,736

Depreciation	11,019	8,903	31,010	24,121

Oil and natural gas:

Operating costs	15,913	9,746	40,916	29,871

Depreciation, depletion

amortization	16,355	12,316	45,632	34,028

Gas gathering and processing:

Operating costs	24,395	10,480	60,616	10,515

Depreciation	902	451	2,267	489

General and administrative	3,324	3,081	10,455	8,955

Interest	885	820	2,157	1,751

Total expenses	139,954	103,613	387,943	262,466

Income Before Income Taxes	91,094	39,737	204,552	96,522

Income Tax Expense:

Current	19,628	1,470	41,185	3,597

Deferred	13,828	13,673	35,385	33,187

Total income taxes	33,456	15,143	76,570	36,784

Equity in Earnings of

Investments, Net of Income Tax	---	53	---	603

Net Income	$	57,638	$	24,647	$	127,982	$	60,341

Net Income per Common Share:

Basic	$	1.25	$	0.54	$	2.79	$	1.32

Diluted	$ 1.25	$ 0.54	$ 2.78	$ 1.31

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

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2005	2004
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 127,982	$ 60,341
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion and amortization	79,520	59,327
Deferred tax expense	35,385	33,559
Other	2,647	(3,464)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(47,742)	(4,968)
Accounts payable	(17,892)	(2,627)
Material and supplies inventory	1,200	(3,476)
Accrued liabilities	8,638	15,241
Prepaid expenses	(909)	(1,874)
Contract advances	1,009	(305)
Other – net	14	17
Net cash provided by operating activities	189,852	151,771
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (including producing property acquisitions and other acquisitions)	(222,157)	(269,103)
Proceeds from disposition of assets	4,772	8,395
Other-net	(4,627)	2,132
Net cash used in investing activities	(222,012)	(258,576)
Cash Flows From (Used In) Financing Activities:		
Borrowings under line of credit	161,800	186,900
Payments under line of credit	(141,700)	(79,800)
Net change in other long-term liabilities	181	(1,833)
Proceeds from exercise of stock options	1,128	424
Book overdrafts	10,814	2,056
Net cash from financing activities	32,223	107,747
Net Increase in Cash and Cash Equivalents	63	942
Cash and Cash Equivalents, Beginning of Year	665	598
Cash and Cash Equivalents, End of Period	$ 728	$ 1,540

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 September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
		(In thousands)		
Net Income	$ 57,638	$ 24,647	$ 127,982	$ 60,341
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	(1,901)	(1,663)	(2,353)	(2,219)
Reclassification - derivative settlements	786	717	888	1,142
Comprehensive Income	$ 56,523	$ 23,701	$ 126,517	$ 59,264

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 directly or indirectly 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 state 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 nine months ended September 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. With respect to the unaudited financial information of Unit Corporation for the three and nine month periods ended September 30, 2005 and 2004, included in this Form 10-Q, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated November 3, 2005 appearing herein, states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a "report" or a "part" of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands except per share amounts)			
Net Income, as Reported	$ 57,638	$ 24,647	$ 127,982	$ 60,341
Add Stock-Based Employee Compensation Expense Included in Reported Net				

Income, Net of Tax	410	318	1,356	756
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(962)	(784)	(2,882)	(1,924)
Pro Forma Net Income	$ 57,086	$ 24,181	$ 126,456	$ 59,173
Basic Earnings per Share:				
As reported	$ 1.25	$ 0.54	$ 2.79	$ 1.32
Pro forma	$ 1.24	$ 0.53	$ 2.76	$ 1.29
Diluted Earnings per Share:				
As reported	$ 1.25	$ 0.54	$ 2.78	$ 1.31
Pro forma	$ 1.23	$ 0.53	$ 2.74	$ 1.29

The following options were granted during the three and nine month periods ending September 30, 2005 and 2004. The fair value of each option granted is estimated using the Black-Scholes model using the estimated values presented in the table:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2005	**2004**	**2005**	**2004**
Options Granted	---	---	58,500	31,500
Estimated Fair Value (In Millions)	---	---	$ 1.3	$ 0.5
Estimate of Stock Volatility	---	---	0.51 to 0.55	0.52
Estimated Dividend Yield	---	---	---	---
Risk Free Interest Rate	---	---	4.35% to 4.42%	4.7%
Expected Life Range Based on Prior Experience (In Years)	---	---	6 to 10	6 to 10

NOTE 2 - EARNINGS PER SHARE

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

WEIGHTED

	INCOME (NUMERATOR)	SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Three Months Ended September 30, 2005:			
Basic earnings per common share	$ 57,638	45,959	$ 1.25
Effect of dilutive stock options	--	270	--
Diluted earnings per common share	$ 57,638	46,229	$ 1.25
For the Three Months Ended September 30, 2004:			
Basic earnings per common share	$ 24,647	45,733	$ 0.54
Effect of dilutive stock options	--	239	--
Diluted earnings per common share	$ 24,647	45,972	$ 0.54

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

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Nine Months Ended September 30, 2005:			
Basic earnings per common share	$ 127,982	45,873	$ 2.79
Effect of dilutive stock options	--	235	0.01
Diluted earnings per common share	$ 127,982	46,108	$ 2.78
For the Nine Months Ended September 30, 2004:			
Basic earnings per common share	$ 60,341	45,709	$ 1.32
Effect of dilutive stock options	--	206	0.01

Diluted earnings per common share	$ 60,341	45,915	$ 1.31

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

NOTE 3 – ACQUISITIONS

On August 31, 2005, the company's wholly owned subsidiary, Unit Texas Drilling L.L.C., closed its acquisition of all the Texas drilling operations of Texas Wyoming Drilling, Inc., a Texas-based privately-owned company, with the exception of one rig which the company subsequently acquired on October 13, 2005. The total purchase price of the acquisition, which includes seven drilling rigs, was $32 million, with $20 million paid in cash and $12 million in stock, representing 246,053 shares. Of the total amount, $13.3 million was paid in cash and $12 million was issued in stock on August 31, 2005. A majority of the rigs are active in the Barnett Shale area of North Texas. Six of the seven drilling rigs are mechanical, and one is a diesel electric rig, They range from 400 to 1,700 horsepower. The results of operations for the six rigs acquired are included in the statement of income for the period after August 31, 2005 and the results of operations for the seventh rig will be included in the statement of income for the period after October 12, 2005.

The $25.3 million acquisition price for the six rigs and related equipment acquired on August 31, 2005 was allocated as follows (in thousands):

Rigs	$ 20,375
Spare Drilling Equipment	896
Drill Pipe and Collars	3,379
Trucks	565
Other Vehicles	35
Total consideration	$ 25,250

On January 5, 2005 the company acquired a subsidiary of Strata Drilling, L.L.C. 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. 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 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 September 30, 2005 and December 31, 2004:

	September 30, 2005	December 31, 2004
	(In thousands)	
Revolving Credit Loan, with Interest at September 30, 2005 and December 31, 2004 of 4.8% and 3.1%, respectively	$ 115,600	$ 95,500
Less Current Portion	--	--
Total Long-Term Debt	$ 115,600	$ 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 is being paid annually. The fees are being amortized over the four year life of the loan.

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 a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. Also included in the borrowing base is an amount representing a part of the value of the company's drilling rig fleet, limited to $20 million, and that amount as the banks reasonably attribute to the cash flow from the company's subsidiary, Superior Pipeline Company, L.L.C. The credit 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 that 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 that 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 September 30, 2005, the company was in compliance with the covenants in its credit agreement.

NOTE 5 – ASSET RETIREMENT OBLIGATIONS

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

The following table shows the activity for the nine months ending September 30, 2005 and 2004 relating to the company's retirement obligation for plugging liability:

	Nine Months Ended	
	2005	2004
	(In Thousands)	
Short-Term Plugging Liability:		
Liability at beginning of period	$ 226	$ 303
Accretion of discount	13	6

Liability settled in the period	(145)	(78)
Liability sold	---	(21)
Reclassification of liability from long-term to short-term	247	16
Plugging liability at end of period	$ 341	$ 226
Long-Term Plugging Liability:		
Liability at beginning of period	$ 18,909	$ 11,691
Accretion of discount	699	619
Liability incurred in the period	1,295	6,048
Liability sold	---	(63)
Reclassification of liability from long-term to short-term	(247)	(16)
Revision of estimates	(833)	---
Plugging liability at end of period	$ 19,823	$ 18,279

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 nine month periods ended September 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. Under the new rules, all of these 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, L.L.C. 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, L.L.C.

NOTE 8 – HEDGING ACTIVITY

The company periodically enters into derivative commodity instruments to hedge its exposure to the fluctuations in the prices it receives for its oil and natural gas production. 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 the following two natural gas collar contracts:

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2004
Prices	Floor of $4.50 and a ceiling of $6.76
Second Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	May through October of 2004
Prices	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.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contracts and the hedge was recognized on the September 30, 2004 balance sheet as a derivative liability of $1.7 million and at a loss of $1.1 million, net of tax, in accumulated other comprehensive income. The natural gas collar contracts increased natural gas revenues by $48,000 during the first nine months of 2004. Oil revenues were reduced by $1.2 million in the third quarter of 2004 due to the settlement of the oil hedge and oil revenues were reduced by $1.9 million for the nine months ended September 30, 2004.

In January 2005, the company entered into the following two natural gas collar contracts.

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19
Second Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	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.

All of these hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the September 30, 2005 balance sheet as a derivative liability of $2.9 million and at a loss of $1.8 million, net of tax, in accumulated other comprehensive income. The natural gas collar contracts decreased natural gas revenues by $1.2 million during the third quarter and first nine months of 2005.

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. As a result of this interest rate swap, the company's interest expense was increased by $0.1 million in the third quarter of 2005 and $0.2 million for the nine months ended September 30, 2005. The fair value of the swap was recognized on the September 30, 2005 balance sheet as current and non-current derivative assets totaling $0.6 million and a gain of $0.3 million, net of tax, in accumulated other comprehensive income.

NOTE 9 - INDUSTRY SEGMENT INFORMATION

The company has three business segments:

- Contract Drilling,
- Oil and Natural Gas Exploration and Production and
- Gas Gathering and Processing

These three segments represent the company's three main business units offering different products and services. The Contract Drilling segment is engaged in the land contract drilling of oil and natural gas wells. The Oil and Natural Gas Exploration and Production segment is engaged in the development, acquisition and production of oil and natural gas properties. The Gas Gathering and Processing segment is engaged in the buying and selling, gathering, processing and treating of natural gas.

The company evaluates the performance of these operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. The company has natural gas production in Canada, which is not significant. Information regarding the company's operations by segment for the three and nine month periods ended September 30, 2005 and 2004 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)			
Revenues:				
Contract drilling	$ 127,119	$ 83,486	$ 336,537	$ 219,647
Elimination of inter-segment revenue	7,246	2,599	14,158	8,436
Contract drilling net of inter-segment revenue	119,873	80,887	322,379	211,211
Oil and natural gas	83,979	46,394	202,819	130,718
Gas gathering and processing	28,720	12,658	71,846	13,495
Elimination of inter-segment revenue	2,159	1,184	5,951	1,933
Gas gathering and processing net of inter-segment revenue	26,561	11,474	65,895	11,562
Other(1)	635	4,595	1,402	5,497
Total revenues	$ 231,048	$ 143,350	$ 592,495	$ 358,988
Operating Income (2):				
Contract drilling	$ 41,693	$ 14,168	$ 96,479	$ 34,354
Oil and natural gas	51,711	24,332	116,271	66,819
Gas gathering and processing	1,264	543	3,012	558
Total operating income	94,668	39,043	215,762	101,731
General and administrative expense	(3,324)	(3,081)	(10,455)	(8,955)
Interest expense	(885)	(820)	(2,157)	(1,751)
Other income - net	635	4,595	1,402	5,497
Income before income Taxes	$ 91,094	$ 39,737	$ 204,552	$ 96,522

(1) Includes in 2004 a $3.8 million gain on the sale of the investment in Eagle Energy Partners I, L.P.

(2) Operating income is total operating revenues less operating expenses, depreciation,

depletion and amortization and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

NOTE 10 – SUBSEQUENT EVENT

On October 7, 2005, the company's wholly owned subsidiary, Unit Petroleum Company, signed a purchase and sale agreement to acquire certain oil and natural gas properties from a group of private entities for approximately $82.4 million in cash. The acquisition consists of approximately 42.5 Bcfe of proved oil and natural gas reserves. The properties are located in Oklahoma, Arkansas and Texas. The acquisition will have an effective date of July 1, 2005. Closing of the acquisition, which is subject to certain conditions contained in the agreement, is anticipated to be mid-November.

On October 13, 2005, the company's wholly owned subsidiary, Unit Texas Drilling L.L.C., paid $6.3 million to close its acquisition of the seventh drilling rig from Texas Wyoming Drilling, Inc. (See Note 3).

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 September 30, 2005, and the related consolidated condensed statements of income and comprehensive income for each of the three and nine month periods ended September 30, 2005 and 2004 and the consolidated condensed statements of cash flows for the nine month periods ended September 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 (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, shareholders' equity and of cash flows for the year then ended (not presented herein), 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
November 3, 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 September 30, 2005, we had cash totaling $0.7 million and we had borrowed $115.6 million of the $150.0 million we had elected to have available under our credit agreement. We are currently in discussions with our banks to increase the credit facility amount by $85 million to $235 million.

On October 13, 2005, the company's wholly owned subsidiary, Unit Texas Drilling L.L.C., paid $6.3 million to close its acquisition of the seventh drilling rig remaining to be acquired from Texas Wyoming Drilling, Inc., a Texas-based privately-owned company and the company's outstanding borrowings under its credit agreement were $121.1 million on that date.

On October 7, 2005, our wholly owned subsidiary, Unit Petroleum Company, signed a purchase and sale agreement to acquire certain oil and natural gas properties from a group of private entities for approximately $82.4 million in cash. Closing of the acquisition is anticipated to be mid-November.

Our three principal business segments are:

- contract drilling carried out by our subsidiaries Unit Drilling Company, Service Drilling Southwest, L.L.C. and Unit Texas Drilling, 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 buying and selling, gathering and processing carried out by our subsidiary Superior Pipeline Company, L.L.C.

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

	September 30, 2005	September 30, 2004	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 56,998	$ 21,574	164%
Long-Term Debt	$ 115,600	$ 107,500	8%
Shareholders' Equity	$ 749,802	$ 576,862	30%
Ratio of Long-Term Debt to Total Capitalization	13%	16%	(19%)
Net Income	$ 127,982	$ 60,341	112%
Net Cash Provided by Operating Activities	$ 189,852	$ 151,771	25%
Net Cash Used in Investing Activities	$ (222,012)	$ (258,576)	14%
Net Cash From Financing Activities	$ 32,223	$ 107,747	(70%)

The following table summarizes certain operating information for the first nine months ended September 30, 2005 and 2004:

	September 30, 2005	September 30, 2004	Percent Change
Oil Production (MBbls)	788	767	3%
Natural Gas Production (MMcf)	24,055	19,855	21%
Average Oil Price Received	$ 48.16	$ 32.17	50%
Average Oil Price Received Excluding Hedge	$ 48.16	$ 34.64	39%
Average Natural Gas Price Received	$ 6.74	$ 5.23	29%
Average Natural Gas Price Received Excluding Hedge	$ 6.79	$ 5.23	30%
Average Number of Our Drilling Rigs in Use During the Period	100.7	85.8	17%
Total Number of Our Drilling Rigs Available at the End of the Period	110	100	10%
Gas Gathered - MMBtu/day	129,754	35,376	267%

Gas Processed - MMBtu/day	32,709	7,141	358%
Number of Natural Gas Gathering Systems	35	30	17%

Our Bank Credit Agreement. At September 30, 2005, we had a $150.0 million bank credit agreement consisting of a revolving credit facility maturing on January 30, 2008. Generally, under the agreement, the banks make a determination (on each redetermination day) of our borrowing base which is how much is available for us to borrow under the agreement based on the banks' valuation of certain of our assets. That amount is determined under the procedures discussed more fully in the next paragraph. Once the banks determine the amount of the borrowing base, we then can elect how much of that amount we want to have available to us under the agreement. The amount we elect is generally referred to as the commitment amount. Under the current agreement, the commitment amount can not exceed $150 million even if the borrowing base is greater than $150 million. We are charged a commitment fee of .375 of 1% on the amount committed but not borrowed by us. We currently have elected to have the full $150.0 million available as the commitment amount. We incurred origination, agency and syndication fees of $515,000 associated with the new agreement, $40,000 of which is being paid annually. The fees are being amortized over the four year life of the loan. The average interest rate for the first nine months of 2005 was 4.5% including the interest incurred from the settlement of our interest rate swap. We are currently in discussions with our banks to increase the credit facility amount by $85 million to $235 million. At September 30, 2005 and November 1, 2005 our borrowings were $115.6 million and $117.6 million, respectively.

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 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 September 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 agreement. The fixed rate is 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was increased by $0.1 million in the third quarter of 2005 and by $0.2 million for the nine months ended September 30, 2005. The fair value of the swap was recognized on the September 30, 2005 balance sheet as current and non-current derivative assets totaling $0.6 million and a gain of $0.3 million, net of tax, in accumulated other comprehensive income.

Contractual Commitments. AtSeptember 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)	$ 126,933	$ 5,111	$ 121,822	$ ---	$ ---
Retirement Agreements (2)	1,938	300	1,381	257	---
Operating Leases (3)	3,498	1,111	1,517	870	---
Drill Pipe, Drilling Rigs and Equipment Purchases (4)	22,682	22,682	---	---	---
Derivative Contracts (5)	2,915	2,915	---	---	---
Total Contractual Obligations	$ 157,966	$ 32,119	$ 124,720	$ 1,127	$ ---

(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 September 30, 2005 interest

rate of 4.8% 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 payments of $31,250 starting in November 2006 and continuing through October 2008. These liabilities as presented above are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston, Midland, and Weatherford, 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 $5.2 million of drill pipe and drill collars. We have committed to purchase $7.7 million of additional rig components for the construction of new rigs with approximately $0.8 million of the amount paid prior to September 30, 2005. We have also committed $15.2

million for the purchase of two drilling rigs with $4.6 million paid prior to September 30, 2005 and the remainder due at delivery in the first quarter of 2006.

(5) We have recorded a $2.9 million liability for the mark-to-market value associated with our oil and natural gas collar. These transactions are discussed further under the hedging section below.

In October 2005, we committed to purchase $22.4 million in drill pipe and drill collars for delivery in 2006 and to purchase $2.3 million of vehicles by the end of April 2006.

At September 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)	$ 2,365	Unknown	Unknown	Unknown	Unknown
Separation Benefit					

Agreement (2)	$ 2,806	$ 496	Unknown	Unknown	Unknown
Plugging Liability (3)	$ 20,164	$ 341	$ 1,538	$ 1,256	$ 17,029
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$ 18,870	$ 6,415	$ 2,128	$ 1,153	$ 9,174

(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 September 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 nine 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 the following two natural gas collar contracts:

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2004
Prices	Floor of $4.50 and a ceiling of $6.76
Second Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	May through October of 2004
Prices	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.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contracts and the hedge was recognized on the September 30, 2004 balance sheet as a derivative liability of $1.7 million and a loss of $1.1 million, net of tax, in accumulated other comprehensive income. The natural gas collar contracts increased natural gas revenues by $48,000 during the first nine months of 2004. Oil revenues were reduced by $1.2 million in the third quarter of 2004 due to the settlement of the oil hedge and oil revenues were reduced by $1.9 million for the nine months ended September 30, 2004.

In January 2005, we entered into the following two natural gas collar contracts.

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19
Second Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	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 period of April through December of 2005 and has a floor of $45.00 and a ceiling of $69.25.

All of these hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the September 30, 2005 balance sheet as a derivative liability of $2.9 million and at a loss of $1.8 million, net of tax, in accumulated other comprehensive income. The natural gas collar contracts decreased natural gas revenues by $1.2 million during the third quarter and first nine months of 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 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. As a result of this interest rate swap, our interest expense was increased by $0.1 million in the third quarter of 2005 and $0.2 million for the nine months ended September 30, 2005. The fair value of the swap was recognized on the September 30, 2005 balance sheet as current and non-current derivative assets totaling $0.6 million and a gain of $0.3 million, net of tax, in accumulated other comprehensive income.

Self-Insurance or Retentions. We are self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.5 million for Oklahoma workers' compensation to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco and the creation of Unit Texas Drilling, L.L.C. we have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for the 19 rigs they operate in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas**.** Natural gas comprises 86% 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 nine month 2005 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $251,000 per month ($3.0 million annualized) change in our pre-tax operating cash flow. Our first nine month 2005 average natural gas price was $6.74 compared to an average natural gas price of $5.23 for the first nine months of 2004. A $1.00 per barrel change in our oil price would have an $82,000 per month ($1.0 million annualized) change in our pre-tax operating cash flow based on our production in the first nine months of 2005. Our first nine month 2005 average oil price was $48.16 compared with an average oil price of $32.17 received in the first nine 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, availability of acquisition opportunities, 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 135 wells (50.25 net wells) in the first nine months of 2005 compared to 110 wells (47.02 net wells) in the first nine months of 2004. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first nine months of 2005 totaled $139.0 million. Based on current prices, we plan to drill an estimated 200 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 and approximately $82.4 million in cash to be paid in the acquisition of certain oil and natural gas properties from a group of private entities in the fourth quarter of 2005. Whether we are able to drill the full number of wells we are planning on drilling is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, the weather and the efforts of outside industry partners.

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. 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.

On October 7, 2005, the company’s wholly owned subsidiary, Unit Petroleum Company, signed a purchase and sale agreement to acquire certain oil and natural gas properties from a group of private entities for approximately $82.4 million in cash. The acquisition consists of approximately 42.5 Bcfe of proved oil and natural gas reserves. The properties are located in Oklahoma, Arkansas and Texas. The acquisition will have an effective date of July 1, 2005, and the results of operations for the properties being acquired from July 1, 2005 to the closing date of this acquisition will be an adjustment to the purchase price of the properties. Closing of the acquisition, which is subject to certain conditions contained in the agreement, is anticipated to be mid-November.

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, our drilling work is not currently being curtailed due to competition from other contractors, but we are experiencing some difficulty in hiring and keeping all of the rig crews we need. To date, however, we have been able to maintain adequate crews to keep all our operating rigs running.

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 nine months of 2005.

To assist in managing our drilling crew requirements, 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. At the end of the second quarter of 2005, we increased wages in our other 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.

We currently do not have any shortages of drill pipe and drilling equipment. Because of the potential for shortages in the availability of new drill pipe, at September 30, 2005 we had commitments to purchase approximately $5.2 million of drill pipe and drill collars and in October of 2005 we committed to purchase another $22.4 million of drill pipe in 2006. We have committed to purchase $7.7 million of additional rig components for the construction of new drilling rigs with approximately $0.8 million of the amount paid prior to September 30, 2005. We have also committed $15.2 million for the purchase of two new drilling rigs with $4.6 million paid prior to September 30, 2005 and the remainder due at delivery in the first quarter of 2006.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells. As a result 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, 2004 and the first nine months of 2005 reached their lowest point 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 nine months of 2005, both demand for our drilling rigs and dayrates have improved. In the first nine months of 2005, the average dayrate we received was $11,583 per day compared to $8,722 per day in the first nine months of 2004. The average use of our drilling rigs in the first nine months of 2005 was 100.7 drilling rigs (98%) compared with 85.8 rigs (95%) for the first nine months of 2004. Based on the average utilization of our drilling rigs during the first nine months of 2005, a $100 per day change in dayrates has a $10,070 per day ($3.7 million annualized) change in our pre-tax operating cash flow. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties for comparable type projects. During the first nine months of 2005 and 2004, we drilled 35 and 34 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $5.6 million and $2.8 million during the nine 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 August 31, 2005, the company's wholly owned subsidiary, Unit Texas Drilling, L.L.C., closed its acquisition of all the Texas drilling operations of Texas Wyoming Drilling, Inc., a Texas-based privately-owned company, with the exception of one rig which the company subsequently obtained on October 13, 2005. The total purchase price of the acquisition, which includes seven drilling rigs, was $32 million, $20 million in cash and $12 million issued in stock, representing 246,053 shares. Of the total amount $13.3 million was paid in cash and $12 million was issued in stock on August 31, 2005. The balance of $6.3 million was paid when the company took possession of the seventh rig on October 13, 2005. A majority of the rigs are active in the Barnett Shale area of North Texas. Six of the seven drilling rigs are mechanical, with one being a diesel electric rig, and range from 400 to 1,700 horsepower. After the acquisition of the seventh rig, our fleet totaled 111 drilling rigs. The results of operations for the first six acquired rigs are included in the statement of income for the period after August 31, 2005 and the results of operations for the seventh rig acquired will be included in the statement of income for the period after October 12, 2005.

On January 5, 2005, we acquired a subsidiary of Strata Drilling, L.L.C. 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. 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 included 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 continues 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 nine months of 2005, we incurred $101.5 million in capital expenditures, which includes $1.1 million in goodwill from the Strata Drilling, L.L.C. 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, L.L.C. 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, the $32

million associated with the seven rigs and related equipment acquired from Texas Wyoming Drilling, Inc., and the $15.2 million purchase price of two rigs currently being constructed by a third party that will be delivered in the first quarter of 2006.

***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 buying and selling, gathering, processing and treating of natural gas. It operates two natural gas treatment plants, owns four processing plants, 35 active gathering systems and 480 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas 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 first nine months of 2005, Superior purchased $4.2 million of our natural gas production, provided gathering and transportation services of $1.6 million and paid $0.1 million for our natural gas liquids which were eliminated from our consolidated condensed financial statements.

During the first nine months of 2005 we incurred $17.8 million in capital expenditures for our natural gas gathering and processing segment. For all of 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.

<u>Oil and Natural Gas Limited Partnerships and Other Entity Relationships</u>. 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 and during the first nine months of 2005 the amount paid was $0.7 million. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

<u>NEW ACCOUNTING PRONOUNCEMENTS</u>

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 nine months ended September 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 September 30, 2005 versus Quarter Ended September 30, 2004

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

	Quarter Ended September 30, 2005	Quarter Ended September 30, 2004	Percent Change
Total Revenue	$ 231,048,000	$ 143,350,000	61%
Net Income	$ 57,638,000	$ 24,647,000	134%
Oil and Natural Gas:			
Revenue	$ 83,979,000	$ 46,394,000	81%
Operating costs	$ 15,913,000	$ 9,746,000	63%
Average natural gas price (Mcf)	$ 8.13	$ 5.21	56%
Average oil price (Bbl)	$ 54.60	$ 34.46	58%
Natural gas production (Mcf)	8,542,000	6,947,000	23%
Oil production (Bbl)	251,000	274,000	(8)%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.62	$ 1.43	13%
Depreciation, depletion and amortization	$ 16,355,000	$ 12,316,000	33%
Drilling:			
Revenue	$ 119,873,000	$ 80,887,000	48%
Operating costs	$ 67,161,000	$ 57,816,000	16%
Percentage of revenue from daywork contracts	100%	100%	---
Average number of rigs in use	102.6	92.0	12%
Average dayrate on daywork contracts	$ 13,117	$ 9,103	44%
Depreciation	$ 11,019,000	$ 8,903,000	24%
Gas Gathering and Processing:			

Revenue	$ 26,561,000	$ 11,474,000	131%
Operating costs	$ 24,395,000	$ 10,480,000	133%
Depreciation	$ 902,000	$ 451,000	100%
Gas gathered – MMbtu/day	159,821	58,436	173%
Gas processed – MMbtu/day	36,061	21,143	71%
General and Administrative Expense	$ 3,324,000	$ 3,081,000	8%
Interest Expense	$ 885,000	$ 820,000	8%
Average Interest Rate	4.89%	2.99%	64%
Average Long-Term Debt Outstanding	$ 104,817,000	$ 98,749,000	6%

Oil and natural gas revenues increased $37.6 million or 81% in the third quarter of 2005 as compared to the third quarter of 2004. Increased oil and natural gas prices accounted for 80% of the increase while increased equivalent natural gas production volumes accounted for 20% of the increase. In the third quarter of 2005, natural gas production increased by 23% while oil

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

Oil and natural gas operating costs increased $6.2 million or 63% in the third quarter of 2005 as compared to 2004. An increase in the average cost per equivalent Mcf produced represented 73% of the increase in production costs with the remaining 27% of the increase attributable to the increase in volumes produced primarily from development drilling. Lease operating expenses represented 50% of the increase, gross production taxes 36% and general and administrative cost directly related to oil and natural gas production 14%. Lease operating expenses per Mcfe increased 21% between the comparative quarters Workover expense represented 49% of the increase while the remaining 51% of the increase is primarily due to increases in the cost of goods and services. Gross production taxes increased due to the increase in natural gas volumes produced and the increase in commodity prices between the comparative quarters. General and administrative expenses increased as labor costs increased primarily due to a 25% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization (“DD&A”) increased $4.0 million or 33%. 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 third quarter of 2005 compared to the third quarter of 2004 resulted primarily from a 21% increase in our finding cost in 2004 and a 3% increase in finding cost incurred in the first nine months of 2005 compared to the finding cost incurred 2004.

Industry demand for our drilling rigs increased throughout 2004 and the first nine months of 2005 as natural gas prices continued to remain above $4.50 per Mcf. Drilling revenues increased $39.0 million or 48% in the third quarter of 2005 versus the third quarter of 2004. In July 2004, we added nine drilling rigs with the acquisition of Sauer Drilling Company, and on August 31 2005, we added six drilling rigs from Texas Wyoming Drilling, Inc. In addition to the Sauer drilling rigs and the Texas Wyoming drilling rigs, we also placed six additional drilling rigs in service since the second quarter of 2004. The 21 additional rigs increased our third quarter 2005 drilling revenues by approximately 18%. The increase in revenue from these additional rigs and the increase in utilization of our previously owned drilling rigs represented 24% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 76% of the increase in total drilling revenues. Our average dayrate in the third quarter of 2005 was 44% higher than in the third quarter of 2004.

Drilling operating costs increased $9.3 million or 16% between the comparative quarters. The increase in operating costs from the 21 drilling rigs placed in service since the third quarter of 2004 and increased utilization of our previously owned drilling rigs represented 71% of the total increase in operating cost. Increases in operating cost per day accounted for 29% of the increase in total operating costs. Operating cost per day increased $283 in the third quarter of 2005 when compared with the third quarter of 2004. A majority 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 and repairs. We expect the demand for drilling rigs to remain high throughout 2005 and into 2006, resulting in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in third quarter of 2004 and we had two footage wells in the third quarter of 2005. Contract drilling

depreciation increased $2.1 million or 24%. The addition of the 21 drilling rigs placed in service since the second quarter of 2004 increased depreciation $0.9 million or 10% 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 buying and selling, gathering, processing and treating of natural gas. Superior operates two natural gas treatment plant and owns four processing plants, 35 active gathering systems and 480 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas.

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 $53,000 net of income tax in the third 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 $15.1 million, $13.9 million and $.05 million higher in the third quarter of 2005 versus 2004, respectively, all due to the Superior acquisition.

Total interest expense increased 8% between the comparative quarters. Average debt outstanding was higher in the third quarter of 2005 as compared to the third quarter of 2004 due to the acquisition of Strata Drilling, L.L.C., the Texas Wyoming drilling rigs and the acquisition of certain oil and natural gas properties in the second quarter of 2005. Average debt outstanding accounted for approximately 5% of the interest expense increase with 11% of the increase resulting from the settlement of the interest rate swap and 84% 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 third quarter of 2005. No interest was capitalized in 2004.

Income tax expense increased $18.3 million or 121% due primarily to the increase in income before income taxes. Our effective tax rate for the third quarter of 2005 was 36.7% versus 38.1% in the third quarter of 2004. The decrease in the effective tax rate resulted primarily from the recognition of a deduction in the third quarter of 2005 relating to domestic production activities as provided by the American Jobs Creation Act. 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 third quarter of 2005 when compared with the third quarter of 2004. Current income tax expense for the third quarter of 2005 and 2004 was $19.6 million and $1.5 million, respectively. Income taxes paid in the third quarter of 2005 were $20.4 million.

On August 2, 2004, the company completed the sale of its investment in Eagle Energy Partners I, L.P. for $6.2 million. In the third quarter of 2004, a pre-tax gain of $3.8 million was recognized in other revenues from this sale.

Nine Months Ended September 30, 2005 versus Nine Months Ended September 30, 2004

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

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Percent Change
Total Revenue	$ 592,495,000	$ 358,988,000	65%
Net Income	$ 127,982,000	$ 60,341,000	112%
Oil and Natural Gas:			
Revenue	$ 202,819,000	$ 130,718,000	55%
Operating costs	$ 40,916,000	$ 29,871,000	37%
Average natural gas price (Mcf)	$ 6.74	$ 5.23	29%
Average oil price (Bbl)	$ 48.16	$ 32.17	50%
Natural gas production (Mcf)	24,055,000	19,855,000	21%
Oil production (Bbl)	788,000	767,000	3%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.58	$ 1.38	14%
Depreciation, depletion and amortization	$ 45,632,000	$ 34,028,000	34%
Drilling:			
Revenue	$ 322,379,000	$ 211,211,000	53%
Operating costs	$ 194,890,000	$ 152,736,000	28%
Percentage of revenue from daywork contracts	100%	100%	---
Average number of rigs in use	100.7	85.8	17%
Average dayrate on daywork contracts	$ 11,583	$ 8,722	33%
Depreciation	$ 31,010,000	$ 24,121,000	29%
Gas Gathering and Processing:			
Revenue	$ 65,895,000	$ 11,562,000	470%
Operating costs	$ 60,616,000	$ 10,515,000	476%
Depreciation	$ 2,267,000	$ 489,000	364%
Gas gathered – MMbtu/day	129,754	35,376	267%
Gas processed – MMbtu/day	32,709	7,141	358%
General and Administrative Expense	$ 10,455,000	$ 8,955,000	17%
Interest Expense	$ 2,157,000	$ 1,751,000	23%
Average Interest Rate	4.46%	2.54%	76%
Average Long-Term Debt Outstanding	$ 95,349,000	$ 76,740,000	24%

Oil and natural gas revenues increased $72.1 million or 55% in the first nine months of 2005 as compared to the first nine months of 2004. Increased oil and natural gas prices accounted for 68% of the increase while increased production volumes accounted for 31% of the increase and increased overhead operating fees accounted for 1% of the increase. Increased production came primarily from our ongoing development drilling activity.

Oil and natural gas operating costs increased $11.0 million or 37% in the first nine months of 2005 as compared to 2004. An increase in the average cost per equivalent Mcf produced represented 51% of the increase in production costs with the remaining 49% attributable to the increase in volumes produced primarily from development drilling. Lease operating expenses represented 48% of the increase, gross production taxes 37% and general and administrative cost directly related to oil and natural gas production 15%. Lease operating expenses per Mcfe increased 8% between the comparative nine month periods Workover expense represented 56% of the increase while the remaining 44% of the increase is primarily due to increases in the cost of goods and services. Gross production taxes increased due to the increase in additional natural gas volumes produced and the increase in commodity prices between the comparative nine month periods. General and administrative expenses increased as labor costs increased primarily attributable to a 32% increase in the average number of employees working in the exploration and production area. Total DD&A increased $11.6 million or 34%. Higher production volumes accounted for 51% of the increase while increases in our DD&A rate represented 49% of the increase. The increase in our DD&A rate in the first nine months of 2005 compared to the first nine 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 nine months of 2005 compared to the finding cost incurred 2004.

Industry demand for our drilling rigs increased throughout 2004 and the first nine months of 2005 as natural gas prices continued to remain above $4.50 per Mcf. Drilling revenues increased $111.2 million or 53% in the first nine months of 2005 versus the first nine months of 2004. In July 2004, we added nine drilling rigs with the acquisition of Sauer Drilling Company, and on August 31 2005, we added six drilling rigs from Texas Wyoming Drilling, Inc. In addition to the Sauer drilling rigs and the Texas Wyoming drilling rigs, we also placed six additional drilling rigs in service since the first nine months of 2004. These 21 additional rigs increased our first nine months of 2005 drilling revenues by approximately 21%. The increase in revenue from the additional rigs and the increase in utilization of our previously owned drilling rigs represented 32% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 68% of the increase in total drilling revenues. Our average dayrate in the first nine months of 2005 was 33% higher than in the first nine months of 2004.

Drilling operating costs increased $42.2 million or 28% between the comparative nine month periods. The increase in operating costs from the 21 drilling rigs placed in service since the first nine months of 2004 and increased utilization of our previously owned drilling rigs represented 61% of the total increase in operating cost. Increases in operating cost per day accounted for 39% of the increase in total operating costs. Operating cost per day increased $591 per day in the first nine months of 2005 when compared with the first nine months of 2004. A majority 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 and repairs. We expect the demand for drilling rigs to remain high throughout 2005 and into 2006, resulting in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in the first nine months of 2004 and we drilled two footage wells in the first nine months of 2005. Contract drilling depreciation increased $6.9 million or 29%. The addition of the 21 drilling rigs placed in service since the first nine months of 2004 increased depreciation $2.9 million or 12% 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 buying and selling, gathering, processing and treating of natural gas. Superior operates two natural gas treatment plant and owns four processing plants, 35 active gathering systems and 480 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas.

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 nine 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 $54.3 million, $50.1 million and $1.8 million higher in the first nine months of 2005 versus 2004, respectively, due to the Superior acquisition.

General and administrative expense increased $1.5 million or 17%. Increases in office cost due to growth within the company and increases 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 $0.4 million or 23%. Average debt outstanding was higher in the first nine months of 2005 as compared to the first nine months of 2004 due to the Superior, Sauer Drilling, Strata Drilling and Texas Wyoming acquisitions and the acquisition of certain oil and natural gas properties in the second quarter of 2005. Average debt outstanding accounted for approximately 21% of the interest expense increase with 13% of the increase resulting from the settlement of the interest rate swap and 66% 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 $1.4 million of interest in the first nine months of 2005. No interest was capitalized in 2004.

Income tax expense increased $39.8 million or 108% due primarily to the increase in income before income taxes. Our effective tax rate for the first nine months of 2005 was 37.4% versus 38.1% in the first nine months of 2004. The decrease in the effective tax rate resulted primarily from the recognition of a deduction in the third quarter of 2005 relating to domestic production activities as provided by the American Jobs Creation Act. 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 nine months of 2005 when compared with the first nine months of 2004. Current income tax expense for the first nine months of 2005 and 2004 was $41.2 million and $3.6 million, respectively. Income taxes paid in the first nine months of 2005 were $36.6 million.

On August 2, 2004, the company completed the sale of its investment in Eagle Energy Partners I, L.P. for $6.2 million. In the third quarter of 2004, a pre-tax gain of $3.8 million was recognized in other revenues from this sale.

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. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, the prices we received for our oil and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first nine months 2005 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $251,000 per month ($3.0 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have an $82,000 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 nine months of 2005, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $0.5 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.

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

Not applicable

Item 5. Other Information

Not applicable

Item 6. Exhibits

Exhibits:

15	Letter re: Unaudited Interim Financial Information.
31.1	Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

UNIT CORPORATION

Date: November 3, 2005 By: /s/ Larry D. Pi

LARRY D. PINKSTON
Chief Executive Officer and
Director

Date:	November 3, 2005	By:	/s/ David T. M

DAVID T. MERRILL
Chief Financial Officer and
Treasurer