UNIT CORP
Form 10-Q
November 04, 2008

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended September 30, 2008

OR

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

For the transition period from _________ to _________

[Commission File Number 1-9260]

UNIT CORPORATION
(Exact name of registrant as specified in its charter)

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

(918) 493-7700
(Registrant's telephone number, including area code)

None
(Former name, former address and former fiscal year,
if changed since last report)

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

Yes [x] No [ ]

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

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

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

Yes [ ]   No [x]

As of October 31, 2008, 47,258,573 shares of the issuer's common stock were outstanding.

FORM 10-Q
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Forward-Looking Statements

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2008	December 31, 2007
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,007	$ 1,076
Restricted cash	19	19
Accounts receivable, net of allowance for doubtful accounts of $3,423 at September 30, 2008 and $3,350 at December 31, 2007	192,119	159,455
Materials and supplies	7,255	13,558
Other	23,940	22,907
Total current assets	224,340	197,015
Property and equipment:		
Drilling equipment	1,123,139	987,184
Oil and natural gas properties, on the full cost method:		
Proved properties	1,997,267	1,624,478
Undeveloped leasehold not being amortized	149,855	64,722
Gas gathering and processing equipment	155,177	119,515
Transportation equipment	24,782	23,240
Other	21,980	19,974
	3,472,200	2,839,113
Less accumulated depreciation, depletion, amortization and impairment	1,098,312	927,759
Net property and equipment	2,373,888	1,911,354
Goodwill	62,808	62,808
Other intangible assets, net	10,371	13,798
Other assets	19,941	14,844
Total assets	$ 2,691,348	$ 2,199,819

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

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

	September 30, 2008	December 31, 2007
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 121,928	$ 100,258
Accrued liabilities	45,919	40,508
Income taxes payable	2,756	—
Contract advances	5,316	6,825
Current portion of derivative liabilities	971	56
Current portion of other liabilities	10,565	8,757
Total current liabilities	187,455	156,404
Long-term debt	148,000	120,600
Other long-term liabilities	90,483	59,115
Deferred income taxes	542,326	428,883
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 47,256,068 and 47,035,089 shares issued, respectively	9,325	9,280
Capital in excess of par value	362,530	344,512
Accumulated other comprehensive income	7,891	1,160
Retained earnings	1,343,338	1,079,865
Total shareholders' equity	1,723,084	1,434,817
Total liabilities and shareholders' equity	$ 2,691,348	$ 2,199,819

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 169,044	$ 157,769	$ 467,519	$ 472,403
Oil and natural gas	152,343	95,231	446,644	277,680
Gas gathering and processing	54,079	32,784	153,102	99,321
Other income (expense), net	97	551	(193)	842
Total revenues	375,563	286,335	1,067,072	850,246
Expenses:				
Contract drilling:				
Operating costs	81,802	77,951	234,541	228,967
Depreciation	18,968	14,793	51,320	41,192
Oil and natural gas:				
Operating costs	32,095	23,101	90,353	69,701
Depreciation, depletion and amortization	40,053	32,297	114,756	92,367
Gas gathering and processing:				
Operating costs	45,381	28,275	125,617	87,171
Depreciation and amortization	3,788	2,858	10,932	7,752
General and administrative	6,928	5,355	20,179	15,784
Interest, net	69	1,797	1,162	5,167
Total operating expenses	229,084	186,427	648,860	548,101
Income before income taxes	146,479	99,908	418,212	302,145
Income tax expense:				
Current	16,026	11,152	41,161	53,498
Deferred	38,172	24,695	113,578	54,538
Total income taxes	54,198	35,847	154,739	108,036
Net income	$ 92,281	$ 64,061	$ 263,473	$ 194,109
Net income per common share:				
Basic	$ 1.98	$ 1.38	$ 5.66	$ 4.19
Diluted	$ 1.96	$ 1.37	$ 5.61	$ 4.16

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

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

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 263,473	$ 194,109
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	177,436	141,968
Deferred tax expense	113,578	54,538
Other	13,325	3,792
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(32,814)	35,023
Accounts payable	(30,603)	(24,497)
Material and supplies inventory	6,303	1,969
Accrued liabilities	16,100	(14,066)
Contract advances	(1,509)	(1,830)
Other – net	(222)	(1,627)
Net cash provided by operating activities	525,067	389,379
INVESTING ACTIVITIES:		
Capital expenditures	(553,660)	(344,524)
Cash paid for acquisitions	(25,727)	(38,500)
Proceeds from disposition of assets	3,783	3,866
Other – net	(2,714)	(388)
Net cash used in investing activities	(578,318)	(379,546)
FINANCING ACTIVITIES:		
Borrowings under line of credit	279,600	144,600
Payments under line of credit	(252,200)	(165,300)
Proceeds from exercise of stock options	2,507	659
Tax benefit from stock options	771	—
Book overdrafts	22,504	10,472
Net cash provided by (used in) financing activities	53,182	(9,569)
Net increase (decrease) in cash and cash equivalents	(69)	264
Cash and cash equivalents, beginning of period	1,076	589
Cash and cash equivalents, end of period	$ 1,007	$ 853

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Net income	$ 92,281	$ 64,061	$ 263,473	$ 194,109
Other comprehensive income, net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $34,277, $(52), $(3,929) and $161	58,361	(122)	(6,721)	(1,026)
Reclassification - derivative Settlements, net of tax of $2,716, $(93), $7,901 and $(158)	4,626	(121)	13,453	(442)
Comprehensive income	$ 155,268	$ 63,818	$ 270,205	$ 192,641

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

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this quarterly report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company," "Unit," "we," "our" and "us" refer to Unit Corporation, a Delaware corporation, and its subsidiaries and affiliates, except as otherwise clearly indicated or as the context otherwise requires.

The accompanying interim condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 28, 2008, for the year ended December 31, 2007. The accompanying condensed consolidated financial statements include all normal recurring adjustments that we consider necessary to state fairly our financial position at September 30, 2008 and results of operations for the three and nine months ended September 30, 2008 and 2007 and cash flows for the nine months ended September 30, 2008 and 2007. All intercompany transactions have been eliminated.

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

Results for the three and nine months ended September 30, 2008 and 2007 are not necessarily indicative of the results to be realized for the full year in the case of 2008, or that we realized for the full year of 2007. With respect to our unaudited financial information for the three and nine month periods ended September 30, 2008 and 2007, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards for a review of that information. Its separate report, dated November 4, 2008, which is included in this quarterly report, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for its report on the unaudited financial information because that report is not a "report" or a "part" of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 - EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended September 30, 2008:			
Basic earnings per common share	$ 92,281	46,634	$ 1.98
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	409	(0.02)
Diluted earnings per common share	$ 92,281	47,043	$ 1.96
For the three months ended September 30, 2007:			
Basic earnings per common share	$ 64,061	46,382	$ 1.38
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	249	(0.01)
Diluted earnings per common share	$ 64,061	46,631	$ 1.37

The number of stock options and stock appreciation rights (SARs) (and their average exercise price) not included in the above computation because their option exercise prices were greater than the average market price of our common stock was:

	2008	2007
Options and SARs	28,000	61,000
Average Exercise Price	$ 73.26	$ 59.67

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2008:			
Basic earnings per common share	$ 263,473	46,568	$ 5.66
Effect of dilutive stock options, restricted stock and SARs	—	366	(0.05)
Diluted earnings per common share	$ 263,473	46,934	$ 5.61
For the nine months ended September 30, 2007:			
Basic earnings per common share	$ 194,109	46,361	$ 4.19
Effect of dilutive stock options, restricted stock and SARs	—	259	(0.03)
Diluted earnings per common share	$ 194,109	46,620	$ 4.16

The number of stock options and SARs (and their average exercise price) not included in the above computation because their option exercise prices were greater than the average market price of our common stock was:

	2008	2007
Options and SARs	28,000	61,000
Average Exercise Price	$ 73.26	$ 59.67

NOTE 3 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

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

	September 30, 2008	December 31, 2007
	(In thousands)	
Revolving credit facility, with interest of 3.8% at September 30, 2008 and 6.0% at December 31, 2007	$ 148,000	$ 120,600
Less current portion	—	—
Total long-term debt	$ 148,000	$ 120,600

On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) which has a maximum credit amount of $400.0 million maturing on May 24, 2012. Borrowings under the Credit Facility are limited to a commitment amount that we can elect. As of September 30, 2008, the commitment amount was $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. When we entered into the Credit Facility, we incurred origination, agency and syndication fees of $737,500 which are being amortized over the life of the agreement. The average interest rate for the third quarter and first nine months of 2008, which includes the effect of our interest rate swaps, was 4.3% and 4.7%, respectively. At September 30, 2008 and October 31, 2008, borrowings were $148.0 million and $180.6 million, respectively.

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

At our election, any part of the outstanding debt under the Credit Facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid on three days prior notice to the administrative agent and on our payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At September 30, 2008, all of our then outstanding borrowings of $148.0 million were subject to LIBOR.

The Credit Facility prohibits:

- 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 properties, except in favor of our lenders.

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

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

On September 30, 2008, we were in compliance with each of these covenants.

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Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2008	December 31, 2007
	(In thousands)	
Plugging liability	$ 63,623	$ 33,191
Derivative liabilities – commodity hedges	817	—
Derivative liabilities – interest rate swaps	566	249
Workers' compensation	24,442	22,469
Separation benefit plans	5,901	4,945
Gas balancing liability	3,364	3,364
Deferred compensation plan	3,063	2,987
Retirement agreements	243	723
	102,019	67,928
Less current portion including derivative liabilities	11,536	8,813
Total other long-term liabilities	$ 90,483	$ 59,115

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning October 1, 2008 through 2013 are $11.5 million, $10.7 million, $3.1 million, $150.2 million and $2.3 million, respectively. Based on the borrowing rates currently available to us for debt with similar terms and maturities, our long-term debt at September 30, 2008 approximates its fair value.

NOTE 4 – ASSET RETIREMENT OBLIGATIONS

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

The following table shows certain information regarding our well plugging liability:

	Nine Months Ended September 30, 2008	2007
	(In thousands)	
Plugging liability, January 1:	$ 33,191	$ 33,692
Accretion of discount	1,345	1,326
Liability incurred	2,432	1,274
Liability settled	(529)	(1,382)
Revision of estimates (1)	27,184	(4,148)

Plugging liability, September 30		63,623		30,762
Less current portion		1,035		1,678
Total long-term plugging liability	$	62,588	$	29,084

(1) Plugging liability estimates were revised upward in the third quarter of 2008 due to the increase in the cost of contract services utilized to plug wells over the last year.

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NOTE 5 - NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), “Noncontrolling Interest in Consolidated Financial Statements – an Amendment to ARB No. 51,” which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. Since we currently do not have any noncontrolling interests, this standard does not presently have an impact on us.

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

NOTE 6 – STOCK-BASED COMPENSATION

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

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For the three and nine months ended September 30, 2008, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.9 million and $8.3 million, respectively, and capitalized stock compensation cost to our oil and natural gas properties of $0.8 million and $2.4 million, respectively. The tax benefit related to this stock based compensation was $1.1 million and $3.1 million, respectively. The remaining unrecognized compensation cost related to unvested awards at September 30, 2008 is approximately $18.6 million with $4.4 million of that amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

For the three and nine months ended September 30, 2007, we recognized stock compensation expense for restricted stock awards, stock appreciation rights and stock options of $1.7 million and $3.3 million, respectively, and capitalized stock compensation cost to our oil and natural gas properties of $0.3 million and $0.6 million, respectively. For the same periods, the tax benefit related to this stock based compensation was $0.6 million and $1.1 million, respectively.

No stock options or SARs were granted during the three month periods ending September 30, 2008 and 2007. The following table estimates the fair value of each stock option granted under all our plans during the periods reflected using the Black-Scholes model applying the estimated values presented in the table:

	Nine Months Ended September 30, 2008	2007
Options granted	28,000	28,000
Estimated fair value (in millions)	$ 0.7	$ 0.6
Estimate of stock volatility	0.32	0.33
Estimated dividend yield	—%	—%
Risk free interest rate	3.00%	5.00%
Expected life based on prior experience (in years)	5	5
Forfeiture rate	5 %	5%

Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate stock option exercise and employee termination rates within the model and aggregate groups of employees that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised. The stock options granted in the first nine months of 2008 increased stock compensation expense for the third quarter and first nine months of 2008 by $0.3 million and $0.5 million, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Shares granted	5,100	409,932	28,350	415,432
Estimated fair value (in millions)	$ 0.3	$ 17.6	$ 1.4	$ 17.9
Percentage of shares granted expected to be distributed	89%	89%	89%	89%

The restricted stock awards granted during the first nine months of 2008 increased our stock compensation expense by $0.2 million and $0.3 million for the third quarter and first nine months of 2008, respectively, and our capitalized cost relating to our oil and natural gas properties increased for both periods by less than $0.1 million.

NOTE 7 – DERIVATIVES

Interest Rate Swaps

From time to time we have entered into interest rate swaps to help manage our exposure to possible future interest rate increases. As of September 30, 2008, we had two outstanding interest rate swaps both of which were cash flow hedges. There was no material amount of ineffectiveness. Our September 30, 2008 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
		($ in thousands)		
December 2007 – May 2012	$ 15,000	4.53%	3 month LIBOR	$ (379)
December 2007 – May 2012	$ 15,000	4.16%	3 month LIBOR	(187)
				$ (566)

Because of these interest rate swaps, interest expense increased by $0.1 million and $0.2 million for the three and nine months ended September 30, 2008. A loss of $0.4 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of September 30, 2008. For the three and nine months ended as of September 30, 2007, we had an outstanding interest rate swap covering $50.0 million of our bank debt that swapped a variable interest rate for a fixed rate. Because of that swap, our interest expense decreased by $0.2 million and $0.5 million for the three and nine months ended September 30, 2007, respectively.

Commodity Hedges

We have entered into various types of derivative instruments covering a portion of our projected natural gas, oil and natural gas liquids (NGLs) production or processing, as applicable, to reduce our exposure to market price volatility. As of September 30, 2008, our derivative instruments consisted of the following types of swaps and collars:

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

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

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

Currently there is no material amount of ineffectiveness on our cash flow hedges. At September 30, 2008, we recorded the fair value of our commodity hedges on our balance sheet as current and non-current derivative assets of $13.9 million and current and non-current derivative liabilities of $0.8 million. During the first nine months of 2007, we had one collar covering 10,000 MMBtus/day for the period January through December of 2007 and two collars covering 10,000 MMBtus/day each for the period March through December 2007. These collars contained prices ranging from a floor of $6.00 to a ceiling of $10.00. In June 2007, we entered into swaps covering approximately 65% of our mid-stream segment's total liquid sales for the period July through November 2007. At September 30, 2007, we had current derivative assets of $1.1 million and current derivative liabilities of $1.6 million.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the sales to revenue and the purchases to expense as the underlying transactions are settled. At September 30, 2008, we had a net gain of $8.8 million, net of tax, from our oil and natural gas segment derivatives and a net loss of $0.5 million, net of tax, from our mid-stream segment derivatives in accumulated other comprehensive income (loss). At September 30, 2008, our short-term commodity instruments had a net fair value asset of $11.2 million and will be settled into earnings within the next twelve months. Our revenues and expenses include realized gains and losses from our commodity derivative settlements as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Increases (decreases) in:				
Oil and natural gas revenue	$ (6,725)	$ 1,784	$ (20,255)	$ 1,936
Gas gathering and processing revenue	(377)	(622)	(1,925)	(622)
Gas gathering and processing expense	116	1,101	(1,005)	1,101
Impact on pre-tax earnings	$ (7,218)	$ 61	$ (21,175)	$ 213

At September 30, 2008, the following cash flow hedges were outstanding:

Oil and Natural Gas Segment:

Term	Sell/ Purch	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Market
Oct – Dec’08	Sell	Crude oil – swap	1,000 Bbl/day	$91.32	WTI - NYMEX
Oct – Dec’08	Sell	Crude oil - collar	1,000 Bbl/day	$85.00 put & $98.75 call	WTI - NYMEX
Oct – Dec’08	Sell	Crude oil - collar	500 Bbl/day	$90.00 put & $102.50 call	WTI - NYMEX
Oct – Dec’08	Sell	Natural gas – swap	20,000 MMBtu/day	$7.52	IF – Centerpoint East
Oct – Dec’08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.00 put & $8.40 call	IF – Centerpoint East
Oct – Dec’08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.20 put & $8.80 call	IF – Tenn (Zone 0)
Oct – Dec’08	Sell	Natural gas - collar	10,000 MMBtu/day	$7.50 put & $8.70 call	NGPL-TXOK
Jan – Dec’09	Sell	Crude oil - collar	500 Bbl/day	$100.00 put & $156.25 call	WTI - NYMEX
Jan – Dec’09	Sell	Natural gas – swap	10,000 MMBtu/day	$7.77	IF – Centerpoint East
Jan – Dec’09	Sell	Natural gas – swap	10,000 MMBtu/day	$8.28	IF – Tenn (Zone 0)
Jan – Dec’09	Sell	Natural gas - collar	10,000 MMBtu/day	$8.22 put & $10.80 call	HH-NYMEX

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Weighted Average Fixed Price	Market
Oct – Dec’08	Sell	Liquid – swap (1)	1,636,845 Gal/mo	$ 1.48	OPIS - Conway
Oct – Dec’08	Purchase	Natural gas – swap	143,180 MMBtu/mo	$ 9.45	IF - PEPL

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

Fair Value Measurements

As of January 1, 2008, we applied the provisions of FAS 157 to our financial instruments. FAS 157 establishes a fair value hierarchy prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1 - unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2 - significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3 - generally unobservable inputs which are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following table sets forth our recurring fair value measurements:

	September 30, 2008			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ —	$ —	$ (566)	$ (566)
Crude oil swaps	—	(836)	—	(836)
Natural gas and NGL swaps and crude oil and natural gas collars	—	—	13,928	13,928

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

The following table is a reconciliation of our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended September 30, 2008		For the Nine Months Ended September 30, 2008	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (343)	$ (78,043)	$ (153)	$ 2,625
Total gains or losses (realized and unrealized):				
Included in earnings (1)	(124)	(4,750)	(179)	(15,130)
Included in other comprehensive income (loss)	(223)	91,971	(413)	11,303
Purchases, issuance and settlements	124	4,750	179	15,130
End of period	$ (566)	$ 13,928	$ (566)	$ 13,928
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held as of September 30, 2008	$ —	$ —	$ —	$ —

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

NOTE 8 - INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

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

The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells. The oil and natural gas segment is engaged in the development, acquisition and production of oil and natural gas properties and the mid-stream segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

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

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)			
Revenues:				
Contract drilling	$ 186,407	$ 169,780	$ 517,430	$ 503,580
Elimination of inter-segment revenue	17,363	12,011	49,911	31,177
Contract drilling net of inter-segment revenue	169,044	157,769	467,519	472,403
Oil and natural gas	152,343	95,231	446,644	277,680
Gas gathering and processing	69,983	40,042	200,271	112,908
Elimination of inter-segment revenue	15,904	7,258	47,169	13,587
Gas gathering and processing net of inter-segment revenue	54,079	32,784	153,102	99,321
Other	97	551	(193)	842
Total revenues	$ 375,563	$ 286,335	$ 1,067,072	$ 850,246
Operating Income (1):				
Contract drilling	$ 68,274	$ 65,025	$ 181,658	$ 202,244
Oil and natural gas	80,195	39,833	241,535	115,612
Gas gathering and processing	4,910	1,651	16,553	4,398
Total operating income	153,379	106,509	439,746	322,254
General and administrative expense	(6,928)	(5,355)	(20,179)	(15,784)
Interest expense, net	(69)	(1,797)	(1,162)	(5,167)
Other income - net	97	551	(193)	842
Income before income taxes	$ 146,479	$ 99,908	$ 418,212	$ 302,145

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of September 30, 2008, and the related condensed consolidated statements of income and comprehensive income for each of the three and nine month periods ended September 30, 2008 and 2007 and the condensed consolidated statements of cash flows for the nine month periods ended September 30, 2008 and 2007. These interim financial statements are the responsibility of the company's management.

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

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2007, and the related consolidated statements of income, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 28, 2008 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2007, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
November 4, 2008

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

Management’s Discussion and Analysis (MD&A) provides an understanding of operating results and financial condition by focusing on changes in key measures from year to year. MD&A is organized in the following sections:

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

MD&A should be read in conjunction with the condensed consolidated financial statements and related notes included in this report as well as the information contained in our most recent Annual Report on Form 10-K.

Unless otherwise indicated or required by the content, when used in this report, the terms “company,” “Unit,” “us,” “our,” “we” and “its” refer to Unit Corporation and/or, as appropriate, one or more of its subsidiaries.

General

We were founded in 1963 as a contract drilling company. Today, we operate, manage and analyze our results of operations through our three principal business segments:

- Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires and produces oil and natural gas properties for our own account.
- Gas Gathering and Processing (Mid-Stream) – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our business and each of our three main operating segments depend, on a large part, on the prices we receive for our natural gas and oil production and the demand for oil and natural gas as well as for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. While our operations are located within the United States, events outside the United States can also impact us and our industry.

Recent events, both within the United States and the World, have brought about significant and immediate changes in the global financial markets which in turn are affecting the United States economy, our industry and us. In the United States, these events and others have had an impact on the prices for oil and natural gas as reflected in the following table:

Date	Gas Spot Price Henry Hub ($ per MMBtu)	Crude Oil WTI-Cushing, OK

				($ per Bbl)
July 1, 2008	$	13.19	$	140.99
August 1, 2008	$	9.26	$	125.10
September 1, 2008	$	8.24	$	115.48
October 1, 2008	$	7.17	$	98.55
November 1, 2008	$	6.20	$	67.81

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As noted in the table, oil and natural gas prices have declined significantly during recent months in a deteriorating national and global economic environment. The current economic environment and the recent decline in commodity prices is causing us (and other oil and gas companies) to reduce our overall level of drilling activity and spending. When drilling activity and spending decline, for any sustained period of time, our dayrates and utilization rates also tend to decline. In addition, lower commodity prices for any sustained period of time could impact the liquidity condition of some of our industry partners and customers, which, in turn, might limit their ability to meet their financial obligations to us.

The recent slowdown in the United States and World economies will also result (to varying degrees) in a reduction in the demand for oil and natural gas products by those industries and consumers that use those products in their business operations. The degree to which that demand is reduced and for how long it may last are unknown at this time. Significant reductions in demand for our commodities would result in lower prices for our products as well as forcing us to curtail our production of those products which, in turn, would affect our financial results.

The impact on our business and financial results as a consequence of the recent volatility in oil and natural gas prices and the global economic crisis is uncertain in the long term, but in the short term, it has had a number of consequences for us, including the following:

- We had previously announced plans, in our contract drilling segment, to build up to eight additional drilling rigs and to buy one additional new drilling rig. Due to the recent declines in commodity prices and the unsettled outlook for commodity prices during 2009, we have cancelled the construction of one of these drillings rigs (the one we had planned to work for our exploration segment) and we are in discussions with the customers for the other seven drilling rigs regarding the possibility of postponing the construction of some of these drilling rigs and instead substituting under the contracts one of our existing drilling rigs.

- We have recently been notified by several of our drilling rig customers that they plan on releasing up to 16 drilling rigs currently under contract. Of those we have already contracted four to other customers.

- We had estimated the number of gross wells to be drilled by our oil and natural gas segment in 2008 to be around 300, we now anticipate that number to be around 275 wells.

- We had previously estimated capital expenditures for our oil and gas segment to be approximately $470.0 million, excluding acquisitions, for 2008. That estimate is now anticipated to be approximately $438.0 million.

Executive Summary

Contract Drilling

Our third quarter 2008 utilization rate was 85% with an average dayrate of $18,644, an increase of 4% from the second quarter of 2008 and 1% from the third quarter of 2007. Direct profit (contract drilling revenue less contract drilling operating expense) increased 20% from the second quarter of 2008 and 9% from the third quarter of 2007, primarily due to the increase in utilization. Operating cost per day decreased 2% from the second quarter of 2008 and 5% from the third quarter of 2007. In the third quarter of 2008, prices for oil and natural gas started to decrease and have continued to decrease or remain at low levels so far during the fourth quarter of 2008 and may, for an unknown period of time continue to decline, which would reduce our dayrates and utilization.

We finished constructing two new 1,500 horsepower diesel electric drilling rigs which were placed into service in the second quarter of 2008 in our Rocky Mountain Division. We also are currently building two additional 1,500 horsepower diesel electric drilling rigs to work in North Dakota; we anticipate the first will be placed into service during the fourth quarter of 2008, and the second during the first quarter of 2009. Regarding the plans for constructing additional drilling rigs see the above discussion in "Business Outlook". Our anticipated 2008 capital expenditures for this segment are $173.0 million.

Oil and Natural Gas

Third quarter 2008 production from our oil and natural gas segment was 172,000 Mcfe per day, a 2% decrease over the second quarter of 2008 and a 13% increase over the third quarter of 2007. The decrease from the second quarter 2008 resulted from the shut-in of approximately 400 MMcfe of production due to the impact Hurricanes Gustav and Ike had on the infrastructure necessary for ongoing production activity in the affected areas and curtailment due to low natural gas prices. The increase from the third quarter 2007 resulted from production from new wells completed throughout 2007 and during the first nine months of 2008. Excluding the impact of Hurricanes Gustav and Ike, third quarter 2008 production would have been approximately 177,000 Mcfe per day.

Oil and natural gas revenues decreased 7% from the second quarter of 2008 and increased 60% from the third quarter of 2007. Our oil and natural gas prices decreased slightly in the third quarter of 2008, decreasing less than 1% and 10%, respectively, while natural gas liquids prices increased 9% from the second quarter of 2008 and our oil, natural gas and NGL prices increased 64%, 42% and 40%, respectively, from the third quarter of 2007. Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 10% from the second quarter of 2008 and increased 67% from the third quarter of 2007. The decrease from the second quarter 2008 resulted from the shut-in of production due to the impact of Hurricanes Gustav and Ike combined with lower natural gas prices. The increase from the third quarter 2007 resulted primarily from the increase in commodity prices and, to a lesser extent, from our increased production. Operating cost per Mcfe produced increased 5% from the second quarter of 2008 and increased 22% from the third quarter of 2007. Excluding the impact of Hurricanes Gustav and Ike, third quarter 2008 operating costs per Mcfe produced would have increased 3% over the second quarter of 2008 and increased 19% over the third quarter of 2007. We hedged 75% of our third quarter 2008 average daily oil production and approximately 35% of our third quarter 2008 average natural gas production in 2008 to help manage our cash flow and capital expenditure requirements in 2008.

Our estimated production for 2008 is approximately 62.0 to 63.0 Bcfe, a 13% to 15% increase over 2007. We now anticipate that we will participate in the drilling of approximately 275 wells during 2008, an increase of 9% over 2007. Our current anticipated 2008 capital expenditures for this segment are $438.0 million (excluding acquisitions). Commodity prices started to decrease during the third quarter of 2008, and may continue to decrease or remain at their current lower levels for an indeterminable period of time beyond 2008. As a result of these lower commodity prices combined with service costs that remain relatively high, we are slowing down our drilling activity during the fourth quarter of 2008 and into 2009. In the Mid-Continent area, natural gas spot prices have been very weak and in certain situations we have shut-in production rather than selling the production at those prices. Our 2008 production estimate of 62.0 to 63.0 Bcfe, is subject to the effect of any extended periods of shut-in production during the fourth quarter of 2008 due to low spot prices.

Mid-Stream

Third quarter 2008 liquids sold per day decreased 1% from the second quarter of 2008 and increased 46% from the third quarter of 2007. Liquids sold per day decreased from the second quarter of 2008; due to the impact Hurricanes Gustav and Ike had on the NGL market in the Gulf Coast area extending into the Mid-continent area, and increased from the third quarter of 2007 primarily as the result of upgrades and expansions to existing plants. Excluding the impact of Hurricanes Gustav and Ike, third quarter 2008 liquids sold per day would have increased 5% over the second quarter of 2008 and increased 54% over the third quarter of 2007. Gas processed per day increased 6% and 28% over the second quarter of 2008 and the third quarter of 2007, respectively. In 2007, we upgraded several of our existing processing facilities and added three processing plants which was the primary reason for increased volumes. Gas gathered per day decreased 5% from the second quarter of 2008 and 12% from the third quarter of 2007 primarily from our Southeast Oklahoma gathering system experiencing natural production declines associated with connected wells.

NGL prices in the third quarter of 2008 increased 1% from the price received in the second quarter of 2008 and increased 30% over the price received in the third quarter of 2007. The price of liquids as compared to natural gas affects the revenue in our mid-stream operations and determines the fractionation spread which is the difference in the value received for the NGLs recovered from natural gas in comparison to the amount received for the equivalent MMBtu's of natural gas if unprocessed. We have hedged 51% of our third quarter 2008 average fractionation spread volumes to help manage our cash flow from this segment in 2008.

Direct profit (mid-stream revenues less mid-stream operating expense) decreased 10% from the second quarter of 2008 and increased 93% from the third quarter of 2007. The decrease from the second quarter 2008 resulted from reduced liquids recoveries due to the negative impact Hurricanes Gustav and Ike had on the NGL market, and the increase from the third quarter 2007 resulted primarily from the combination of both increased commodity prices and volumes processed and sold. Total operating cost for our mid-stream segment increased less than 1% from the second quarter of 2008 and 60% from the third quarter of 2007. Our anticipated capital expenditures for 2008 for this segment, excluding acquisitions, are $48.0 million. Commodity prices declined in the third quarter of 2008, and may continue to decrease or remain at their current lower levels for an indeterminable period of time beyond 2008, which could result in fewer wells being connected to existing gathering systems resulting in possible future declines in volumes or margins.

Financial Condition and Liquidity

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

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

The following is a summary of certain financial information as of September 30, 2008 and 2007 and for the nine months ended September 30, 2008 and 2007:

	September 30, 2008	September 30, 2007	% Change (1)
	(In thousands except percentages)		
Working capital	$ 36,885	$ 48,159	(23)%
Long-term debt	$ 148,000	$ 153,600	(4)%
Shareholders’ equity	$ 1,723,084	$ 1,358,611	27%
Ratio of long-term debt to total capitalization	8%	10%	(20)%
Net income	$ 263,473	$ 194,109	36%
Net cash provided by operating activities	$ 525,067	$ 389,379	35%
Net cash used in investing activities	$ (578,318)	$ (379,546)	52%
Net cash provided by (used in) financing activities	$ 53,182	$ (9,569)	NM

(1) NM – A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

The following table summarizes certain operating information:

	Nine Months Ended September 30, 2008	2007	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	105.3	98.4	7%
Total number of drilling rigs owned at the end of the period	131	128	2%
Average dayrate	$ 18,190	$ 18,858	(4)%
Oil and Natural Gas:			
Oil production (MBbls)	942	792	19%
Natural gas liquids production (MBbls)	962	468	106%
Natural gas production (MMcf)	35,143	32,507	8%
Average oil price per barrel received	$ 99.33	$ 64.04	55%
Average oil price per barrel received excluding hedges	$ 112.15	$ 64.04	75%
Average NGL price per barrel received	$ 56.87	$ 39.44	44%
Average NGL price per barrel received excluding hedges	$ 56.78	$ 39.44	44%
Average natural gas price per mcf received	$ 8.35	$ 6.30	33%
Average natural gas price per mcf received excluding hedges	$ 8.58	$ 6.24	38%
Mid-Stream:			
Gas gathered—MMBtu/day	200,652	221,943	(10)%
Gas processed—MMBtu/day	66,219	47,432	40%
Gas liquids sold — gallons/day	195,303	115,781	69%
Number of natural gas gathering systems	36	36	—%
Number of processing plants	8	7	14%

At September 30, 2008, we had unrestricted cash totaling $1.0 million and we had borrowed $148.0 million of the $275.0 million we had elected to have available under our Credit Facility. Our Credit Facility is used for working capital and capital expenditures. Most of our capital expenditures are discretionary and directed toward future growth.

Working Capital. Typically, our working capital balance fluctuates primarily because of the timing of our accounts receivable and accounts payable. We had working capital of $36.9 million and $48.2 million as of September 30, 2008 and 2007, respectively. The effect of our hedging activity increased working capital by $7.0 million as of September 30, 2008 and reduced working capital by $0.1 million as of September 30, 2007.

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

If current industry utilization decreases continue, we anticipate the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future requirements of the drilling industry will start to lessen. Likewise, if current industry utilization declines continue, we do not anticipate our labor costs to increase from levels in effect at the beginning of the fourth quarter of 2008.

Most of our drilling rig fleet is used to drill natural gas wells so natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we charge for our contract drilling services. As natural gas prices declined late in 2006 and the first part of 2007, demand for drilling rigs also declined. As a result, dayrates throughout the drilling industry generally declined. For the first nine months of 2008, our average dayrate was \$18,190 per day compared to \$18,858 per day for the first nine months of 2007. The average number of our drilling rigs used in the first nine months of 2008 was 105.3 drilling rigs (81%) compared with 98.4 drilling rigs (81%) in the first nine months of 2007. Based on the average utilization of our drilling rigs during the first nine months of 2008, a \$100 per day change in dayrates has a \$10,530 per day (\$3.8 million annualized) change in our pre-tax operating cash flow. We expect that utilization and dayrates for our drilling rigs will decline to some extent in the fourth quarter of 2008 and into 2009, as a result of the recent economic condition and lower commodity prices.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services contain the same terms and rates as the contracts we use with unrelated third parties for comparable type projects. During the first nine months of 2008 and 2007, we drilled 93 and 52 wells, respectively, for our exploration and production segment. The profit our drilling segment received from drilling these wells, $21.5 million and $15.7 million, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit. The slowing down of our oil and natural gas segment's drilling activity during the fourth quarter of 2008 and into 2009, will reduce the drilling services our contract drilling segment provides for our oil and natural gas segment.

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

Based on our first nine months of 2008 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $366,000 per month ($4.4 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production during the first nine months of 2008 was $8.35 compared to $6.30 for the first nine months of 2007. Based on our first nine months of 2008 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $99,000 per month ($1.2 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $100,000 per month ($1.2 million annualized) change in our pre-tax operating cash flow based on our production in the first nine months of 2008. In the first nine months of 2008, our average oil price per barrel received was $99.33 compared with an average oil price of $64.04 in the first nine months of 2007 and our first nine months of 2008 average NGLs price per barrel received was $56.87 compared with an average NGL price per barrel of $39.44 in the first nine months of 2007.

Because natural gas prices have such a significant effect on the value of our oil, NGLs and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our Credit Facility because that determination is based mainly on the value of our oil, NGLs and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of our oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. Full cost companies are required to use the unescalated prices in effect as of the end of each fiscal quarter to calculate the discounted future revenues. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs, even if prices are depressed for only a short period of time. Under the SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

No impairment was necessary for the third quarter 2008. Since oil and natural gas prices can be volatile, we may be required to write down the carrying value of our oil and natural gas properties at the end of future reporting periods. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from

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operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

We sell most of our natural gas production to third parties under month-to-month contracts.

Mid-Stream Operations. Our mid-stream operations are engaged primarily in the buying and selling, gathering, processing and treating of natural gas. This segment operates three natural gas treatment plants, eight processing plants, 36 gathering systems and 755 miles of pipeline. In addition, this segment enhances our ability to gather and market not only our own natural gas production but also that owned by third parties as well as providing us with additional opportunities to construct or acquire existing natural gas gathering and processing facilities. During the first nine months of 2008 and 2007, our mid-stream operations purchased $44.0 million and $10.0 million, respectively, of our oil and natural gas segment’s production and provided gathering and transportation services to it of $3.2 million and $3.6 million, respectively. The increase in the production purchased from our oil and natural gas segment was primarily due to a purchasing agreement entered into in the second quarter of 2007, relating to production in the Texas panhandle. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas exploration segment has been eliminated in our consolidated condensed financial statements.

Gas gathering volumes in the first nine months of 2008 were 200,652 MMBtu per day compared to 221,943 MMBtu per day in the first nine months of 2007, processed volumes were 66,219 MMBtu per day in the first nine months of 2008 compared to 47,432 MMBtu per day in the first nine months of 2007 and the amount of NGLs sold were 195,303 gallons per day in the first nine months of 2008 compared to 115,781 gallons per day in the first nine months of 2007. Gas gathering volumes per day in 2008 decreased 10% compared to 2007 primarily due to a volumetric decline in our Southeast Oklahoma gathering system due to natural production declines associated with the connected wells and the shutdown for approximately 10 days during February 2008 of a third-party processing plant on a different system. Processed volumes increased 40% over the comparative nine months and NGLs sold also increased 69% over the comparative period primarily due to the addition of three natural gas processing plants in 2007.

Our Credit Facility. Our Credit Facility, which has a maximum credit amount of $400.0 million, matures on May 24, 2012. Borrowings under the Credit Facility are limited to a commitment amount that we can elect. As of September 30, 2008, the commitment amount was $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of our total borrowing base amount. When we entered into the Credit Facility, we incurred origination, agency and syndication fees of $737,500 which are being amortized over the life of the agreement. The average interest rate for the first nine months of 2008, which includes the effect of our interest rate swaps, was 4.7% compared to 6.1% for the first nine months of 2007. At September 30, 2008 and October 31, 2008, our borrowings were $148.0 million and $180.6 million, respectively.

The lenders under our Credit Facility and their respective participation interests are as follows:

Lender	Participation Interest
Bank of Oklahoma, N.A.	18.75%
Bank of America, N.A.	18.75%
BMO Capital Markets Financing, Inc.	18.75%
Compass Bank	12.50%
Comerica Bank	08.75%
Fortis Capital Corp.	08.75%
Calyon New York Branch	08.75%
Sterling Bank	05.00%

100.00%

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

At our election, any part of the outstanding debt under the Credit Facility may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid on three days prior notice to the administrative agent and on our payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under the LIBOR bear interest at the BOKF National Prime Rate payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without premium or penalty. At September 30, 2008, all of our then outstanding borrowings of $148.0 million were subject to LIBOR.

The Credit Facility prohibits:

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

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

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

On September 30, 2008, we were in compliance with each of these covenants.

Due to the recent tightening of the credit markets, if we were to renegotiate our Credit Facility or undertake additional financing, we would not expect to be able to acquire financing with terms as favorable or economical as our current Credit Facility.

Capital Requirements

Contract Drilling Acquisitions and Capital Expenditures. During 2006, we purchased major components for use in constructing two new 1,500 horsepower drilling rigs. The first was placed into service in our Rocky Mountain division at the end of March 2007 and the second was placed into service in the second quarter of 2007. The combined capitalized cost of these two drilling rigs was $19.4 million.

On June 5, 2007, we completed the acquisition of Leonard Hudson Drilling Co., Inc., a privately-owned drilling company operating primarily in the Texas Panhandle. The acquired company owned nine drilling rigs, a fleet of 11 trucks, and an office, shop and equipment yard. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities ranging from 10,000 to 15,000 feet. Results of operations for the acquired company have been included in our statements of income beginning June 5, 2007. Total consideration paid for this acquisition was $38.5 million.

In 2007, this segment recorded $220.4 million in capital expenditures including the effect of a $19.4 million deferred tax liability and $5.3 million in goodwill associated with the acquisition of Leonard Hudson Drilling. As of September 30, 2008, this segment has spent $144.0 million in capital expenditures. For the full year of 2008, we anticipate capital expenditures for this segment will be approximately $173.0 million, excluding acquisitions. We have constructed two new 1,500 horsepower diesel electric drilling rigs and placed these drilling rigs into service in our Rocky Mountain division during the second quarter of 2008. Also, we are currently building two additional 1,500 horsepower diesel electric drilling rigs to work in North Dakota; we anticipate the first will be placed into service during the fourth quarter of 2008, and the second during the first quarter of 2009. We had previously announced plans, in our contract drilling segment, to build up to eight additional drilling rigs and to buy one additional new drilling rig. Due to the recent declines in commodity prices and the unsettled outlook for commodity prices during 2009, we have cancelled the construction of one of these drillings rigs (the one we had planned to work for our exploration segment) and we are in discussions with the customers for the other seven drilling rigs regarding the possibility of postponing the construction of some of these drilling rigs and instead substituting under the contracts one of our existing drilling rigs.

We currently do not have a shortage of drill pipe and drilling equipment. At September 30, 2008, we had commitments to purchase approximately $83.9 million of new rig components, drill pipe, drill collars and related equipment over the next twelve months.

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

On June 1, 2008, we acquired a 25% non-operated working interest in oil and gas leases covering 152,000 gross acres located in Pennsylvania and Maryland.

In September 2008, we completed an acquisition consisting of a 75% working interest in four producing wells and other proved undeveloped properties for $22.2 million along with an 83% to 100% working interest in undeveloped leasehold valued at approximately $3.5 million all located in the Texas Panhandle region.

Our decision to increase our oil, NGLs and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. Due to limited availability of acquisitions that met our economic criteria in 2007, we focused on our drilling program. During the first nine months of 2008, we participated in the drilling of 211 gross wells (102.62 net wells) compared to 172 gross wells (60.24 net wells) in the first nine months of 2007. Capital expenditures for the first nine months of 2008 for this segment, excluding our acquisitions and plugging liability, totaled $387.6 million. Currently we plan to participate in drilling an estimated 275 gross wells in 2008 and estimate our associated total capital expenditures will be approximately $438.0 million, excluding acquisitions. Whether and if we are able to drill the full number of planned wells is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, prices for oil, NGLs and natural gas, the cost to drill wells, the weather, changes to our anticipated cash flow and the efforts of outside industry partners. Commodity prices have decreased during the third quarter of 2008, and may continue to decrease or remain at their current lower levels for an indeterminable period of time beyond 2008. As a result of these lower commodity prices combined with service costs that remain relatively high, we are slowing down our drilling activity during the fourth quarter of 2008 and into 2009.

As of September 30, 2008, we had commitments to purchase casing for $8.4 million.

Mid-Stream Acquisitions and Capital Expenditures. During the first nine months of 2008, this segment incurred $35.7 million in capital expenditures as compared to $25.2 million in the first nine months of 2007. For 2008, we have budgeted capital expenditures of approximately $48.0 million. We anticipate that growth in this segment will be through the construction of new facilities or acquisitions.

As of September 30, 2008, we had commitments to purchase two new processing plants for a remaining commitment of $6.3 million. Both plants will be held for future growth or expansion of existing facilities.

Contractual Commitments. At September 30, 2008, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Bank debt (1)	$ 169,212	$ 5,785	$ 11,570	$ 151,857	$ —
Retirement agreements (2)	243	243	—	—	—
Operating leases (3)	3,363	2,089	1,197	77	—
Drill pipe, drilling components and equipment purchases (4)	101,045	101,045	—	—	—
Total contractual obligations	$ 273,863	$ 109,162	$ 12,767	$ 151,934	$ —

(1) See previous discussion in MD&A regarding our Credit Facility. This obligation is presented in accordance with the terms of the Credit Facility and includes interest calculated using our September 30, 2008 interest rate of 3.9% which includes the effect of the interest rate swaps.

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

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

(4) For the next twelve months, we have committed to purchase approximately $83.9 million of new drilling rig components, drill pipe, drill collars and related equipment, $8.4 million of casing, 107 vehicles for $2.5 million and a remaining $6.3 million for two new processing plants. Both plants will be held for future growth or expansion of existing facilities.

At September 30, 2008, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Estimated Amount of Commitment Expiration Per Period			
Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Deferred compensation plan (1)	$ 3,063	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 5,901	$ 243	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$ 817	$ 817	$ —	$ —	$ —
Derivative liabilities – interest rate swaps	$ 566	$ 154	$ 309	$ 103	$ —
Plugging liability (3)	$ 63,623	$ 1,035	$ 9,369	$ 2,856	$ 50,363
Gas balancing liability (4)	$ 3,364	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$ 24,442	$ 9,044	$ 4,108	$ 1,549	$ 9,741

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheet, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments, the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. Currently there are no participants in the Senior Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. At September 30, 2008, there were 39 eligible employees to participate in the Special Plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143 (FAS 143), "Accounting for Asset Retirement Obligations," we have recorded the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2008, with a subsidiary of ours serving as general partner. The Partnerships were formed for the

purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner’s interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $241,000 and $7,000 in 2008 and 2006, respectively, and did not have any repurchases in 2007.

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

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

Interest Rate Swaps. From time to time we have entered into interest rate swaps to help manage our exposure to possible future interest rate increases under our Credit Facility. As of September 30, 2008, we had two outstanding interest rate swaps which were cash flow hedges. There was no material amount of ineffectiveness. Our September 30, 2008 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
		($ in thousands)		
December 2007 – May 2012	$ 15,000	4.53%	3 month LIBOR	$ (379)
December 2007 – May 2012	$ 15,000	4.16%	3 month LIBOR	(187)
				$ (566)

Because of these interest rate swaps, interest expense increased by $0.1 million and $0.2 million for the three and nine months ended September 30, 2008. A loss of $0.4 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of September 30, 2008. For the three and nine months ended as of September 30, 2007, we had an outstanding interest rate swap covering $50.0 million of our bank debt that swapped a variable interest rate for a fixed rate. Because of that swap, our interest expense decreased by $0.2 million and $0.5 million for the three and nine months ended September 30, 2007, respectively.

Commodity Hedges. We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our products is based, in part, on our view of current and future market conditions. For 2008, in an attempt to better manage our cash flows, we increased the amount of our hedged production. As of October 31, 2008, the approximated percentages of our third quarter 2008 average daily production which is hedged is as follows:

Oil and Natural Gas Segment:

	Oct – Dec'08	Jan – Dec'09
Daily oil production	75%	15%
Daily natural gas production	35%	35%

Mid-Stream Segment:

	Oct – Dec'08
Ethane frac spread	52%
Propane frac spread	62%

Iso-butane frac spread	38%
Normal butane frac spread	39%
Gasoline frac spread	40%

With respect to the commodities subject to the hedge, the use of hedging limits the risk of adverse downward price movements, however it also limits increases in future revenues that would otherwise result from favorable price movements.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties in our valuation at September 30, 2008 and determined it was immaterial at that time. At October 31, 2008, Bank of Montreal, Bank of Oklahoma, N.A. and Bank of America, N.A. were the counterparties with respect to all of our commodity hedging transactions. At September 30, 2008, the fair values of the net assets we had with each of these counterparties was $7.7 million, $1.9 million and $3.5 million, respectively.

Currently there is no material amount of ineffectiveness on our cash flow hedges. At September 30, 2008, we recorded the fair value of our commodity hedges on our balance sheet as current and non-current derivative assets of $13.9 million and current and non-current derivative liabilities of $0.8 million. During the first nine months of 2007, we had one collar covering 10,000 MMBtus/day for the period January through December of 2007 and two collars covering 10,000 MMBtus/day each for the period March through December 2007. These collars contained prices ranging from a floor of $6.00 to a ceiling of $10.00. In June 2007, we entered into swaps covering approximately 65% of our mid-stream segment's total liquid sales for the period July through November 2007. At September 30, 2007, we had current derivative assets of $1.1 million and current derivative liabilities of $1.6 million.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the sales to revenue and the purchases to expense as the underlying transactions are settled. As of September 30, 2008, we had a net gain of $8.8 million, net of tax, from our oil and natural gas segment derivatives and a net loss of $0.5 million, net of tax, from our mid-stream segment derivatives in accumulated other comprehensive income (loss). At September 30, 2008, our short-term commodity instruments had a net fair value asset of $11.2 million and will be settled into earnings within the next twelve months. Our revenues and expenses include realized gains and losses from our commodity derivative settlements as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Increases (decreases) in:				
Oil and natural gas revenue	$ (6,725)	$ 1,784	$ (20,255)	$ 1,936
Gas gathering and processing revenue	(377)	(622)	(1,925)	(622)
Gas gathering and processing expense	116	1,101	(1,005)	1,101
Impact on pre-tax earnings	$ (7,218)	$ 61	$ (21,175)	$ 213

Stock and Incentive Compensation. During the first nine months of 2008, we granted awards covering 28,350 shares of restricted stock. These awards were granted as retention incentive awards. During the first nine months of 2008, we recognized compensation expense of $8.3 million for all of our restricted stock, stock options and SAR grants and capitalized $2.4 million of compensation cost for oil and natural gas properties. The first nine months of 2008 restricted stock awards had an estimated fair value as of the grant date of $1.4 million. Compensation expense will be recognized over the three year vesting periods and, during the first nine months of 2008, we recognized $0.3 million in additional compensation expense and capitalized less than $0.1 million for these awards.

Self-Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.5 million for Oklahoma workers' compensation, as well as claims under our occupational injury benefits plan to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. If our insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. We have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for part of our drilling operations in the State of Texas in lieu of covering them under Texas workers' compensation.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner of 13 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. For the first nine months of 2008 and 2007, the total we received for all of these fees was $1.4 million and $1.1 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

New Accounting Pronouncements

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

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

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

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), "Noncontrolling Interest in Consolidated Financial Statements – an Amendment to ARB No. 51," which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. Since we currently do not have any noncontrolling interests, this standard does not presently have an impact on us.

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

Results of Operations

Quarter Ended September 30, 2008 versus Quarter Ended September 30, 2007

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

	Quarter Ended September 30, 2008	Quarter Ended September 30, 2007	Percent Change
Total revenue	$ 375,563,000	$ 286,335,000	31%
Net income	$ 92,281,000	$ 64,061,000	44%
Contract Drilling:			
Revenue	$ 169,044,000	$ 157,769,000	7%
Operating costs excluding depreciation	$ 81,802,000	$ 77,951,000	5%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	110.7	100.3	10%
Average dayrate on daywork contracts	$ 18,644	$ 18,470	1%
Depreciation	$ 18,968,000	$ 14,793,000	28%
Oil and Natural Gas:			
Revenue	$ 152,343,000	$ 95,231,000	60%
Operating costs excluding depreciation, depletion and amortization	$ 32,095,000	$ 23,101,000	39%
Average oil price (Bbl)	$ 101.82	$ 62.01	64%
Average NGL price (Bbl)	$ 61.78	$ 44.18	40%
Average natural gas price (Mcf)	$ 8.20	$ 5.77	42%
Oil production (Bbl)	316,000	297,000	6%
NGL production (Bbl)	306,000	173,000	77%
Natural gas production (Mcf)	12,134,000	11,206,000	8%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.51	$ 2.29	10%
Depreciation, depletion and amortization	$ 40,053,000	$ 32,297,000	24%
Mid-Stream Operations:			
Revenue	$ 54,079,000	$ 32,784,000	65%
Operating costs excluding depreciation and amortization	$ 45,381,000	$ 28,275,000	60%
Depreciation and amortization	$ 3,788,000	$ 2,858,000	33%
Gas gathered—MMBtu/day	195,914	221,508	(12)%
Gas processed—MMBtu/day	71,260	55,721	28%
Gas liquids sold—gallons/day	199,805	137,098	46%
General and administrative expense	$ 6,928,000	$ 5,355,000	29%
Interest expense, net	$ 69,000	$ 1,797,000	(96)%
Income tax expense	$ 54,198,000	$ 35,847,000	51%
Average interest rate	4.3%	6.1%	(30)%
Average long-term debt outstanding	$ 142,059,000	$ 182,385,000	(22)%

Contract Drilling:

Drilling revenues increased $11.3 million or 7% in the third quarter of 2008 versus the third quarter of 2007 primarily due to a 10% increase in the average number of rigs in use during the third quarter of 2008 compared to the third quarter of 2007. Average drilling rig utilization increased from 100.3 drilling rigs in the third quarter of 2007 to 110.7 in the third quarter of 2008. The additional drilling rigs in use increased revenue between the comparative periods by $16.3 million, partially offset by a $5.0 million reduction in revenue from a decrease in revenue per day caused by decreases in mobilization revenue. Our average dayrate in the third quarter of 2008 was 1% higher than in the third quarter of 2007. In the third quarter of 2008, prices for oil and natural gas started to decrease and have continued to decrease or remain at their current lower levels so far during the fourth quarter of

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2008 and may continue to do so, for an unknown period of time, which we anticipate would act to reduce our future dayrates and utilization.

Drilling operating costs increased $3.9 million or 5% between the comparative third quarters of 2008 and 2007 primarily due to the increase in the number of drilling rigs used. Our labor costs increased late in the third quarter of 2008, due to adjustments to rig crew personnel compensation. However if current industry utilization decreases continue, we anticipate the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future requirements of the drilling industry will start to lessen. Likewise, if current industry utilization declines continue, we do not anticipate our labor costs to increase from levels in effect at the beginning of the fourth quarter of 2008, and upward pressure on other daily drilling costs should also be reduced. Contract drilling depreciation increased $4.2 million or 28% as the total number of drilling rigs owned increased between the comparative periods.

Oil and Natural Gas:

Oil and natural gas revenues increased $57.1 million or 60% in the third quarter of 2008 as compared to the third quarter of 2007 due to an increase in average oil, NGL and natural gas prices and a 13% increase in equivalent production volumes. Average oil prices between the comparative quarters increased 64% to $101.82 per barrel, NGL prices increased 40% to $61.78 per barrel and natural gas prices increased 42% to $8.20 per Mcf. In the third quarter of 2008, as compared to the third quarter of 2007, oil production increased 6%, NGL production increased 77% and natural gas production increased 8%. Increased production came primarily from our ongoing internal development drilling activity. With the continuation of our internal drilling program, our total production for 2008 compared to 2007 is anticipated to increase approximately 13% to 15%. However, whether this increased production will (and to what extent) increase our revenues will be determined to a large part by the prices we receive for our production. Commodity prices started to decrease during the third quarter of 2008, and may continue to decrease or remain at their current lower levels for an indeterminable period of time beyond 2008. As a result of lower commodity prices combined with service costs that remain relatively high, we are slowing down our drilling activity during the fourth quarter of 2008 and into 2009.

Oil and natural gas operating costs increased $9.0 million or 39% between the comparative third quarters of 2008 and 2007. An increase in the average cost per equivalent Mcf produced represented 64% of the increase in operating costs with the remaining 36% of the increase attributable to the increase in volumes produced from wells added from our developmental drilling. Increases in general and administrative expenses directly related to oil and natural gas production and gross production taxes from higher revenues contributed to the majority of the operating cost increase. General and administrative expenses increased as labor costs increased primarily due to a 19% increase in the average number of employees working in the exploration and production area while lease operating expenses increased primarily due to an increase in the number of wells producing and also from increases in the cost of goods purchased and third-party services. Gross production taxes increased primarily as a result of the increase in oil and natural gas revenues. Total depreciation, depletion and amortization ("DD&A") increased $7.8 million or 24%. Higher production volumes accounted for 55% of the increase while increases in our DD&A rate represented 45% of the increase. The increase in our DD&A rate in the third quarter of 2008 compared to the third quarter of 2007 resulted primarily from increases in the cost of oil and natural gas reserves added in 2007 and the first nine months of 2008 due to higher drilling and completion costs. The increase in commodity prices over the last two years has increased the cost of acquiring producing properties. However, recent decreases in commodity prices, combined with nation-wide concerns regarding credit availability may lead to less competition for producing property acquisitions.

Mid-Stream:

Our mid-stream revenues were $21.3 million or 65% higher for the third quarter of 2008 as compared to the third quarter of 2007 due to the higher NGL volumes processed and sold combined with higher NGL and natural gas prices.

The average price for NGLs sold increased 30% and the average price for natural gas sold increased 45%. Gas processing volumes per day increased 28% between the comparative quarters and NGLs sold per day increased 46% between the comparative quarters. A 12% decrease in gathering volumes per day partially offset the increase in revenue from natural gas liquids and processing sales. The significant increase in volumes processed per day is primarily attributable to the installation of three processing plants in 2007 and, to a lesser extent, volumes added from new wells connected to existing systems throughout 2007 and during the first nine months of 2008. NGLs sold volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes decreased primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma. NGL sales were reduced by $0.4 million in the third quarter of 2008 compared to $0.6 million in the third quarter of 2007 due to the impact of NGL hedges.

Operating costs increased $17.1 million or 60% in the third quarter of 2008 compared to the third quarter of 2007 due to a 22% increase in natural gas volumes purchased per day and a 45% increase in prices paid for natural gas purchased, a 34% increase in field direct operating expense due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and a 169% increase in general and administrative expenses associated with our mid-stream segment. The total number of employees working in our mid-stream segment increased by 71%. Depreciation and amortization increased $0.9 million, or 33%, primarily attributable to the additional depreciation associated with assets acquired between the comparative periods. Operating costs increased by $0.1 million in the third quarter of 2008 compared to $1.1 million in the third quarter of 2007 due to the impact of natural gas purchase hedges. Should the recent decline in commodity prices cause a reduction in the wells drilled by non-affiliated companies, our ability to connect additional wells to our existing gathering systems would be reduced resulting in possible future declines in our volumes or margins.

Other:

General and administrative expense increased $1.6 million or 29% in the third quarter of 2008 compared to the third quarter of 2007. This increase was primarily attributable to increased stock based compensation costs and increased payroll expenses due to a 10% increase in the number of employees.

Total interest expense, net of capitalized interest, decreased $1.7 million or 96% between the comparative quarters. Our average debt outstanding and our average interest rate were 22% and 29% lower, respectively, in the third quarter of 2008 as compared to the third quarter of 2007. We capitalized interest based on the net book value associated with our undeveloped inventory of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Capitalized interest reduced our interest expense by an additional $0.5 million in the third quarter of 2008 versus the third quarter of 2007 and represented 29% of the $1.7 million decrease in interest expense. Interest expense was increased $0.1 million for the third quarter of 2008 and was reduced $0.2 million for the third quarter of 2007 from interest rate swap settlements.

Income tax expense increased $18.4 million or 51% due primarily to the increase in income before income taxes. Our effective tax rate for the third quarter of 2008 was 37% versus 36% for the third quarter of 2007 with the change due primarily to the decrease in manufacturing tax deduction for 2008. The portion of our taxes reflected as current income tax expense for the third quarter of 2008 was $16.0 million or 30% of total income tax expense for the third quarter of 2008 as compared with $11.2 million or 31% of total income tax expense in the third quarter of 2007. The reduction in the percentage of tax expense recognized as current is the result of expected bonus depreciation on equipment and increased intangible drilling costs to be deducted in the current year. Income taxes paid in the third quarter of 2008 were $14.7 million.

Nine Months Ended September 30, 2008 versus Nine Months Ended September 30, 2007

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

	Nine Months Ended September 30, 2008	2007	Percent Change
Total revenue	$ 1,067,072,000	$ 850,246,000	26%
Net income	$ 263,473,000	$ 194,109,000	36%
Contract Drilling:			
Revenue	$ 467,519,000	$ 472,403,000	(1)%
Operating costs excluding depreciation	$ 234,541,000	$ 228,967,000	2%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	105.3	98.4	7%
Average dayrate on daywork contracts	$ 18,190	$ 18,858	(4)%
Depreciation	$ 51,320,000	$ 41,192,000	25%
Oil and Natural Gas:			
Revenue	$ 446,644,000	$ 277,680,000	61%
Operating costs excluding depreciation, depletion and amortization	$ 90,353,000	$ 69,701,000	30%
Average oil price (Bbl)	$ 99.33	$ 64.04	55%
Average NGL price (Bbl)	$ 56.87	$ 39.44	44%
Average natural gas price (Mcf)	$ 8.35	$ 6.30	33%
Oil production (Bbl)	942,000	792,000	19%
NGL production (Bbl)	962,000	468,000	106%
Natural gas production (Mcf)	35,143,000	32,507,000	8%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.45	$ 2.29	7%
Depreciation, depletion and amortization	$ 114,756,000	$ 92,367,000	24%
Mid-Stream Operations:			
Revenue	$ 153,102,000	$ 99,321,000	54%
Operating costs excluding depreciation and amortization	$ 125,617,000	$ 87,171,000	44%
Depreciation and amortization	$ 10,932,000	$ 7,752,000	41%
Gas gathered—MMBtu/day	200,652	221,943	(10)%
Gas processed—MMBtu/day	66,219	47,432	40%
Gas liquids sold—gallons/day	195,303	115,781	69%
General and administrative expense	$ 20,179,000	$ 15,784,000	28%
Interest expense, net	$ 1,162,000	$ 5,167,000	(78)%
Income tax expense	$ 154,739,000	$ 108,036,000	43%
Average interest rate	4.7%	6.1%	(23)%
Average long-term debt outstanding	$ 131,531,000	$ 175,408,000	(25)%

Contract Drilling:

Drilling revenues decreased $4.9 million or 1% in the first nine months of 2008 versus the first nine months of 2007 primarily due to decreases in dayrates between the comparative periods. As natural gas prices declined late in 2006 and the first part of 2007, demand for drilling rigs also declined. As a result, dayrates throughout the industry have declined as rig contractors attempted to maintain rig utilization levels. Our average dayrate in the first nine months of 2008 was 4% lower than in the first nine months of 2007. Decreases in revenue per day between the comparative periods decreased revenue by $40.0 million. This decrease was partially offset by a $35.1 million increase in revenues from additional drilling rigs in use as the average drilling rigs we had available increased 6% over the comparative periods from both construction and the acquisition completed in June 2007. Average drilling rig utilization increased from 98.4 drilling rigs in the first nine months of 2007 to 105.3 in the first nine months of 2008. In the third quarter of 2008, prices for oil and natural gas started to decrease and have continued to decrease or remain at their current lower levels so far during the fourth quarter of 2008 and may continue to do so, for an unknown period of time, which we anticipate would act to reduce our future dayrates and utilization.

Drilling operating costs increased $5.6 million or 2% between the comparative first nine months of 2008 and 2007 primarily due to the increase in drilling rigs used. The increase was partially offset by the intercompany elimination as we drilled 93 wells for our oil and natural gas segment in the first nine months of 2008 compared to 52 wells in the first nine months of 2007. Further increases resulted from the additional yard, trucks and autos associated with our June 2007 rig acquisition. Our labor costs increased late in the third quarter of 2008, due to adjustments to rig crew personnel compensation. However as current industry utilization decreases continue, we anticipate the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future requirements of the drilling industry will start to lessen. Likewise, if current industry utilization declines continue, we do not anticipate our labor costs to increase from levels in effect at the beginning of the fourth quarter of 2008, and upward pressure on daily drilling cost should also be reduced. Contract drilling depreciation increased $10.1 million or 25% as the total number of drilling rigs owned increased between the comparative periods.

Oil and Natural Gas:

Oil and natural gas revenues increased $169.0 million or 61% in the first nine months of 2008 as compared to the first nine months of 2007 due to an increase in average oil, NGL and natural gas prices and a 16% increase in equivalent production volumes. Average oil prices between the comparative periods increased 55% to $99.33 per barrel, NGL prices increased 44% to $56.87 per barrel and natural gas prices increased 33% to $8.35 per Mcf. In the first nine months of 2008, as compared to the first nine months of 2007, oil production increased 19%, NGL production increased 105% and natural gas production increased 8%. Increased production came primarily from our ongoing internal developmental drilling activity. We experienced some curtailment of production in the third quarter of 2008 due to low natural gas prices, in the first quarter of 2008 and the second quarter of 2007 due to the shut-in of a third-party processing plant and during the first quarter of 2007 from a fire at a third-party refinery. With the continuation of our internal drilling program, our total production for 2008 compared to 2007 is anticipated to increase approximately 13% to 15%. However, whether this increased production will (and to what extent) increase our revenues will be determined to a large part by the prices we receive for our production. Commodity prices started to decrease during the third quarter of 2008, and may continue to decrease or remain at their current lower levels for an indeterminable period of time beyond 2008. As a result of lower commodity prices combined with service costs that remain relatively high, we are slowing down our drilling activity during the fourth quarter of 2008 and into 2009.

Oil and natural gas operating costs increased $20.7 million or 30% between the comparative first nine months of 2008 and 2007. An increase in the average cost per equivalent Mcf produced represented 42% of the increase in operating costs with the remaining 58% of the increase attributable to the increase in volumes produced from wells added from our developmental drilling. Increases in general and administrative expenses directly related to oil and natural gas production and gross production taxes from higher revenues contributed to the majority of the operating cost increase. General and administrative expenses increased as labor costs increased primarily due to a 20% increase in the average number of employees working in the exploration and production area while lease operating expenses increased primarily due to an increase in the number of wells producing and also from increases in the cost of goods purchased and third-party services. Gross production taxes increased primarily as a result of the increase in oil and natural gas revenues. Total DD&A increased $22.4 million or 24%. Higher production volumes accounted for 67% of the increase while increases in our DD&A rate represented 33% of the increase. The increase in our DD&A rate in the first nine months of 2008 compared to the first nine months of 2007 resulted primarily from increases in the cost of oil and natural gas reserves added in 2007 and the first nine months of 2008 due to higher drilling and completion costs. The increase in commodity prices over the last two years has increased the cost of acquiring producing properties. However, recent decreases in commodity prices, combined with nation-wide concerns regarding credit availability may lead to less competition for producing property acquisitions.

Mid-Stream:

Our mid-stream revenues were $53.8 million or 54% higher for the first nine months of 2008 as compared to the first nine months of 2007 due to the higher NGL volumes processed and sold combined with higher NGL and natural gas prices. The average price for NGLs sold increased 34% and the average price for natural gas sold increased 36%. Gas processing volumes per day increased 40% between the comparative periods and NGLs sold per day increased 69% between the comparative periods. A 10% decrease in gathering volumes per day partially offset the increase in revenue from NGLs and processing sales. The significant increase in volumes processed per day is primarily attributable to the installation of three processing plants in 2007 and, to a lesser extent, volumes added from new wells connected to existing systems throughout 2007 and during the first nine months of 2008. NGLs sold volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes decreased primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma and the shutdown of a third-party processing plant in another location in February 2008 for approximately 10 days. NGL sales were reduced by $1.9 million due to the impact of NGL hedges in the first nine months of 2008 compared to $0.6 million in the first nine months of 2007.

Operating costs increased $38.4 million or 44% in the first nine months of 2008 compared to the first nine months of 2007 due to a 28% increase in natural gas volumes purchased per day and a 39% increase in prices paid for natural gas purchased, a 32% increase in field direct operating expense due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and a 103% increase in general and administrative expenses associated with our mid-stream segment. The total number of employees working in our mid-stream segment increased by 47%. Depreciation and amortization increased $3.2 million, or 41%, primarily attributable to the additional depreciation associated with assets acquired between the comparative periods. Operating costs were reduced by $1.0 million in the first nine months of 2008 compared to an increase of $1.1 million in the first nine months of 2007 due to the impact of natural gas purchase hedges. Should the recent decline in commodity prices cause a reduction in the wells drilled by non-affiliated companies, our ability to connect additional wells to our existing gathering systems would result in possible future declines in our volumes or margins.

Other:

General and administrative expense increased $4.4 million or 28% in the first nine months of 2008 compared to the first nine months of 2007. This increase was primarily attributable to increased stock based compensation costs and increased payroll expenses due to a 9% increase in the number of employees.

Total interest expense, net of capitalized interest, decreased $4.0 million or 78% between the comparative nine month periods. Our average debt outstanding and our average interest rate was 25% and 22% lower, respectively, for the first nine months of 2008 as compared to the first nine months of 2007. We capitalized interest based on the net book value associated with our undeveloped inventory of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Capitalized interest reduced our interest expense by an additional $0.6 million for the first nine months of 2008 versus the first nine months of 2007 and represented 15% of the $4.0 million decrease in interest expense. Interest expense was increased $0.2 million for the nine months of 2008 and was reduced $0.5 million for the nine months of 2007 from interest rate swap settlements.

Income tax expense increased $46.7 million or 43% due primarily to the increase in income before income taxes. Our effective tax rate for the first nine months of 2008 was 37% versus 36% for the first nine months of 2007 with the change due primarily to the decrease in manufacturing tax deduction for 2008. The portion of our taxes reflected as current income tax expense for the first nine months of 2008 was $41.2 million or 27% of total income tax expense for the first nine months of 2008 as compared with $53.5 million or 50% of total income tax expense in the first nine months of 2007. The reduction in the percentage of tax expense recognized as current is the result of expected bonus depreciation on equipment and increased intangible drilling costs to be deducted in the current year. Income taxes paid in the first nine months of 2008 were $33.3 million.

Safe Harbor Statement

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

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- our exploration prospects;
- estimates of our proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas reserves;
- growth potential for our mid-stream operations;
- gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates; and
- our belief that the final outcome of our legal proceedings will not materially affect our financial results.

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;
- the time period associated with the current decrease in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Our operations are exposed to market risks primarily because of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil 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 of 2008 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $366,000 per month ($4.4 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $99,000 per month ($1.2 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $100,000 per month ($1.2 million annualized) change in our pre-tax operating cash flow.

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

At October 31, 2008, the following cash flow hedges were outstanding:

Oil and Natural Gas Segment:

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

		Crude oil - collar		\$100.00 put & \$156.25 call	
Jan – Dec'09	Sell	Natural gas – swap	10,000 MMBtu/day	\$5.74	IF – PEPL
Jan – Dec'09	Sell	Natural gas – swap	20,000 MMBtu/day	\$6.95	IF – Centerpoint East
Jan – Dec'09	Sell	Natural gas – swap	10,000 MMBtu/day	\$8.28	IF – Tenn (Zone 0)
Jan – Dec'09	Sell	Natural gas - collar	10,000 MMBtu/day	\$8.22 put & \$10.80 call	HH-NYMEX

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Weighted Average Fixed Price	Market
Oct – Dec'08	Sell	Liquid – swap (1)	1,636,845 Gal/mo	\$ 1.48	OPIS - Conway
Oct – Dec'08	Purchase	Natural gas – swap	143,180 MMBtu/mo	\$ 9.45	IF - PEPL

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

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving Credit Facility may be fixed at the LIBOR Rate for periods of up to 180 days. To help manage our exposure to any future interest rate volatility, we currently have two $15.0 million interest rate swaps, one at a fixed rate of 4.53% and one at a fixed rate of 4.16%, both expiring in May 2012. Based on our average outstanding long-term debt subject to the floating rate in the first nine months of 2008, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $1.0 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of September 30, 2008 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended September 30, 2008 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, as defined in Rule 13a – 15(f) under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed below and in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2007, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Except as set forth below, there have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2007.

Recent events in the financal markets and the economy could adversely affect our operations and financial condition.

As a result of recent volatility in oil and natural gas prices and substantial uncertainty in the capital markets due to the deteriorating global economic environment, we are unable to determine whether customers will reduce spending on exploration and development drilling or whether customers and/or vendors and suppliers will be able to access financing necessary to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations. The deteriorating global economic environment may impact industry fundamentals, and the potential resulting decrease in demand for drilling rigs could cause the drilling industry to cycle into a downturn. These conditions could have a material adverse effect on our business, financial condition and results of operations.

If demand for oil and natural gas is reduced, our ability to market as well as produce our oil and natural gas may be negatively affected.

Historically, oil and gas prices have been extremely volatile, with significant increases and significant price drops being experienced from time to time. In the future, various factors beyond our control will have a significant effect on oil and gas prices. Such factors include, among other things, the domestic and foreign supply of oil and gas, the price of foreign imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity and changes in existing and proposed federal regulation and price controls.

The natural gas market is also unsettled due to a number of factors. In the past, production from natural gas wells in some geographic areas of the United States was curtailed for considerable periods of time due to a lack of market demand. Over the past several years demand for natural gas has increased greatly limiting the number of wells being shut in for lack of demand. It is possible, however, that some of our wells may in the future be shut-in or that natural gas will be sold on terms less favorable than might otherwise be obtained should demand for gas lessen in the future. Competition for available markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Natural gas surpluses could result in our inability to market natural gas profitably, causing us to curtail production and/or receive lower prices for our natural gas, situations which would adversely affect us.

Recent disruptions in the financial markets could affect our ability to obtain financing or refinance existing indebtedness on reasonable terms and may have other adverse effects.

Widely-documented commercial-credit market disruptions have resulted in a tightening of credit markets in the United States. Liquidity in the global-credit markets has been severely contracted by these market disruptions making terms for certain financings less attractive, and in certain cases, have resulted in the unavailability of certain types of financing. As a result of ongoing credit-market turmoil, we may not be able to obtain debt financing, or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

The counterparties to our commodity derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. The recent worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

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

The following table provides information relating to our repurchase of common stock for the three months ended September 30, 2008:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2008 to July 31, 2008	330	$ 77.97	330	—
August 1, 2008 to August 31, 2008	—	—	—	—
September 1, 2008 to September 30, 2008	—	—	—	—
Total	330	$ 77.97	330	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the July 16, 2008 vesting distribution for grants previously made from our “Unit Corporation Stock and Incentive Compensation Plan” adopted May 3, 2006.

(2) The price paid per common share represents the closing sales price of a share of our common stock as reported by the NYSE on the day that the stock was acquired by us.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. 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.

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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 4, 2008	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: November 4, 2008	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer